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MASTER'S THESIS

ECONOMIC ANALYSIS OF A TRIGENERATION SYSTEM – THE CASE OF ERA CITY, SKOPJE

Ljubljana, September 2016 ALEKSANDRA STOJANOVSKA

AUTHORSHIP STATEMENT

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INTRODUCTION

- **Problem background**

Nowadays, investors and owners of commercial buildings and commercial businesses are increasingly seeking ways to use energy more efficiently. This is mostly because of the increasing electricity rates, decreased power reliability (blackouts or other power interruptions), as well as the competitive and economic pressures to cut expenses, increase air quality, and reduce emissions of air pollutants and greenhouse gases (Goodell, 2003). On the other hand, energy demand is expected to increase by around 40% between 2006 and 2030 in the USA alone, according to the Energy Information Administration's International Energy Outlook from 2009 (Al-Sulaiman, 2010), while a dramatic increase in greenhouse gas emissions is also foreseen. For instance, from 1990 to 2007 the U.S. Environmental Protection Agency in the Inventory of U.S. Greenhouse Gas Emissions and Sinks declared that the CO_2 equivalent emissions increased 17% in the USA (Al-Sulaiman, 2010).

That is why in the last few years "ecogeneration" is becoming a preferred method to produce energy. Ecogeneration defines the optimization of economic and ecological benefits in the power generation process. The process produces huge savings for our environment through the reduction, or even elimination, of pollutants associated with power and energy production. Additionally, according to research from Brunel University and collaborators (Milnes, 2011), ecogeneration appeals to the real bottom line, by providing the investors/owners with significant fuel and energy savings.

Energy technologies that fall under ecogeneration include: wind, solar, geothermal, hydrogen fuel, hydrogen fuel cells, soybean diesel fuels, ocean/tidal power, waste to energy/waste to fuel and waste to watts, combined cycle, district energy, cogeneration, trigeneration, and even quadgeneration power plants. My master's thesis will elaborate the trigeneration systems' increasing importance due to the growing demand of energy and increased environmental awareness (Sevilgen, 2011). The trigeneration systems offer a possibility to obtain electricity, heat and cooling with the consumption of one fuel (Morton, 2010). In addition to higher utilization of the fuel, this concept also offers substantially decreased Freons or Chlorofluorocarbon/Hydro-chlorofluorocarbons (hereinafter: CFC/HCFC) refrigerants and reduction of all air pollutants compared to conventional systems in which these three forms of energy are generated individually. Trigeneration systems, also referred to as trigeneration power plants, combined heating, cooling and power (hereinafter: CHCP), building cooling, heating and power (hereinafter: BCHP) and integrated energy systems, permit even greater operational flexibility for businesses with demand for heating and cooling energy (Goodell, 2003).

The investor in the study is Era Group, a modern, international and multi-business group, focused on business development. Their core business is the electricity industry, mining and agriculture, which they have broadened, adapted and expanded over time and across borders into areas of South Eastern Europe. The trade activity is transformed into total care for professional buyers. In addition, they are focused on generating international business connections and developing the business environment in which they operate. Together with Eko-Energetika they intend to enrich the Skopje Fair in Skopje, Macedonia, with a modern business and commercial centre **Era City,** and also to design and construct an ecologic Eko-Energetika project – a trigeneration system.

The commercial and business shopping centre ERA CITY Skopje will provide various services and products (multi-cinema, bowling, restaurants, fitness, wellness etc.), and the building complex will also be used for business purposes. The business centre will have ten-story ground levels and three underground levels. The construction of several smaller ancillary facilities such as garage, petrol station and others is also anticipated in the project.

Emho (2003) points out that trigeneration can be designed and operated to supply all the energy demand of the system. The trigeneration system is planned in the first building of the complex in order to provide energy for the entire complex: heating energy in winter time, cooling energy in summer time and electricity during the whole year. In short, the investor wants to have a comprehensive modern technological solution that is user-and environment-friendly, while ensuring reliable operation of the facility at all times. The produced electricity could also be used as a backup solution in case of power failure of the city electrical grid. In case of higher prices of the produced electricity compared to the prices of the electricity offered by EVN, the Macedonian electrical distribution company, the produced electricity and/or the produced surplus can be sold to the electrical distribution system in the Republic of Macedonia.

Natural gas will be the input energy source in this trigeneration system. The complex will be independent of external suppliers of energy for heating and cooling, with its own electrical power generation unit, which will be able to satisfy at least the minimum demand of electricity needed by the complex at any moment.

In later stages, an expansion of the supply of produced energy is planned to the existing two business buildings and the six pavilions for the Skopje Fair Exhibition facilities and the Intercontinental Hotel located near ERA CITY shopping centre.

The European Union (hereinafter: EU) is also widely recognizing the environmental benefits and the potential security of supply benefits from the cogeneration and trigeneration. According to Smit (2006, p. 1), about 10% of all electricity produced in EU member states comes from cogeneration or trigeneration. He explains that this percentage will be increased over the next few years, due to the European Commission’s support of the use of cogeneration and trigeneration in various directives that are to be implemented by the EU member states. Well-chosen policies can overcome barriers to trigeneration, states Kerr (2009) in his report for the International Energy Agency (hereinafter: IEA). The analysis that IEA took discovered that barriers exist in many places in the world that prevent trigeneration and cogeneration to reach their full potential and only targeted policies can remove these obstacles to achieve the benefits of CHCP.

- **Problem definition**

The thesis gives an answer to the investors' question: is investment into energy efficiency a good decision? The investor in a trigeneration plant needs to calculate with two types of cost: the initial costs for installing the cogeneration plant (purchase of the cogeneration unit, connection to the power grid, the fuel system and the heating system, construction and engineering) and the long-term costs for fuel and maintenance of the system. That is why one of my goals is to calculate the costs that appear and compare possible costs if the investor chooses another input fuel. In this study I also investigate the profitability of the proposed sizing of the trigeneration plant, which is capable to respond to changes in the demand for the three types of energy; electricity, heat and cooling in the ERA City complex.

The investor can sell the electricity produced on the Macedonian electricity market. The master's thesis reviews the policies and regulations that a company must comply with in order to become an electricity vendor. I have also calculated the possible profit from the sale of electricity produced. The economic analysis takes into account the input parameters and construction guidelines provided by the investor, the data collected from sources like the Macedonian Hydro-meteorological Institute, and simulation values of individual consumption of the different types of energy (heating, cooling, and electricity) with respect to the expected temperature deficit or surplus of the buildings complex. The simulation is performed on the basis of input data for a reference period of one year. The results of the analysis stand as basis for the optimal design of the necessary equipment and facilities.

In the end, I show how different market conditions influence the profitability of the investment, by applying the market conditions of Slovenia in the analysis. In this, I have used secondary data collected on web sites and statistical primary data from relevant sources.

- **Research goals**

The purpose of the master's thesis is to investigate the economic effects of constructing a trigeneration system in Era City, Skopje, Macedonia. It investigates the potential benefits and costs, and the circumstances in which this system is profitable, having in mind the market conditions in Macedonia and whether the investor generates profits in the role of electricity producer on the Macedonian market.

Having in mind the wide applicability and great potential of trigeneration worldwide, I compared the analyses results for building a trigeneration system in Macedonia and in Slovenia, an EU member country. Considering the same technology and different market condition (such as the prices of fuels, energy, etc.), I have made a comparative analysis of the ROI for a trigeneration system in Slovenia. The major research questions that the master's thesis answers are:

- How does building a trigeneration power plant differ from conventional energy supply systems?
- What is the pay-back period of the investment?
- What is the dependency of the pay-back period of the investment and the profitability of the power plant on the price of the fuels and on the price of electricity generated?
- Should the investor consider a different fossil fuel or energy source as source fuel for the power plant?
- What does a profitability comparison of the same project done in an EU member country (Slovenia) show?

The master's thesis will be of practical value to the management of ERA CITY and also to any investor who wants to invest in trigeneration systems. It also provides a larger picture of the investment possibilities in Macedonia vs. EU in lieu of different market conditions.

- **Research methodology**

The research methods first comprise review of theoretical literature on the subject of cogeneration and trigeneration systems. I relied on professional literature from domestic and foreign authors, articles with the latest findings related to this subject and scientific contributions published in professional journals and web sites.

In the master thesis I perform a financial investment analysis of the project ERA CITY. This analysis will help answer the main questions raised previously. It will be based on the primary data and projections provided by the investor and statistical data collected from relevant sources like the Macedonian Hydro-meteorological Institute. The data is used for various quantitative analyses.

A comparative analysis has been included in the study in order to investigate the differences in profitability of the same project in different market conditions. Secondary data collected from web sites are used, as well as statistical data from relevant sources as required in the analysis. In this master thesis I have illustrated the principles of capital budgeting by examining a trigeneration project explained in detail below.

1 METHODOLOGICAL APPROACH FOR ECONOMIC ANALYSIS OF INVESTMENT PROJECTS

The first chapter in my master thesis provides a theoretical overview of the capital budgeting methods commonly applied in economic analysis for appraisal of investment projects. Summary of the types of investment projects cash flows and their assessments is given. I also elaborate in detail the static and dynamic methods of capital budgeting for assessing the performance of the investment and risk management.

1.1 Overview of Capital Budgeting and Investments

Investments are the driving force of the entire economy, and the most important development factor for economic growth. According to Pučko they are vital for the development and growth of businesses (Pučko & Rozman, 1992, p. 295). By investing, the companies make strategic directions for future operations and define their strategy. The resources needed to finance the investments are limited and scarce. That is why the decision whether a project is an acceptable investment is one of the most important in business decision-making. Depending on the project, the funding is often associated with high financial resources tied over a long period of time. Long-term investment decisions are associated with uncertainty and risks. The long-term performance of the company will depend on the selection of investments that will provide the highest yields (Lorie & Savage, 1955, p. 1). These methods assist the decision makers in choosing the investment projects by evaluating their technological acceptance, market potential, financial and economic viability, risk, etc. (Lužnik & Crucify, 1991, pp. 9, 125). More specifically, the decision affects how the company will work (define the set of products and services that define their offer), where it will work (structural characteristics that determine the capacity and the geographical dispersion of its operations), and how it will work (the complexity of the operational processes and the labour used). There are several definitions for investments:

Investing is the process of putting to optimum use of present available resources in order to achieve positive effects in the future. According to this definition, investing in capital investments can bring benefits, but only after a certain time and therefore there is a delay between the time of investment and time of the benefits. (Benedeković, D., Benedeković J., Brozović, Jančin & Lasic, 2007, p. 59). According to Rebernik (2004, p. 277) companies invest, because in the long term without investment they may not provide the competitive edge and/or the technological efficiency and, consequently, will be unable to ensure economic efficiency and growth. Due to the time gap between today's investing cash and cash effects in future, the investments are closely linked with risks. Pučko and Rozman (1992, p. 294) define the investment as investing in financial resources. In a narrower sense, the investment is any expenditure of funds for the purchase of goods or assets that the company uses for a long period of time. The broader sense investing in resources includes working capital, securities, human capital and research and development.

The objective of any company is to increase the profitability and elevate its value for the shareholders. That is why companies are looking for business opportunities, ways to identify, evaluate and choose the best way to realize them and finally benefit from the results. Capital budgeting (or investment appraisal) is the decision process that the managers use to determine whether a long term investment in a project such as new machinery, replacement machinery, new plants, new products, and research development projects are worth the funding through the company's capitalization structure (debt, equity or retained earnings). It is the process of allocating resources for major capital or investment expenditures. The results of capital budgeting set the strategic direction of the company, because they last for many years and reduce the flexibility of the company. According to Brigham (2005, p. 344) if the company invests too much, it will have unnecessary high depreciation and other expenses. If there are not enough investments from the company, the equipment and software might not be sufficiently modern to enable it to produce competitively. If it has inadequate capacity, it may lose market share to rival companies and regaining lost customers is a costly process because it involves activities like heavy selling expenses, price reductions or product improvements. According to Shank (1996, pp. 47-65) the investment decision making process comprises of four steps:

- identifying investment opportunities/projects;
- quantitative analysis of individual cash flows;
- assessment of the qualitative elements that cannot be integrated into the analysis of cash flows;
- making the investment decision.

The first step, identifying the investment opportunity, is a very important step, even though it is not supported with literature, due to the difficulty of formalization and the big diversity. In the first step the projects are analysed from different perspectives (Maccarrone, 1996):

- current market condition; whether the investment projects will bring competitive advantage aligned with the strategy and development plans of the company;
- growth of the company: the availability, experience and knowledge of the resources in the organizational structure, linked to the company strategic planning and the informational system;

• the specifics regarding the project itself, like the size and complexity, its possible dependency upon other projects, the availability of financial resources considering the other projects of the company;
• having in mind the duration of the project, the inherent risk of the project itself and in relation to the overall risk of the company.

The ideas for investments can come from the market, from the production needs and plans of the company, the strategic decisions to improve operations, innovate and find new competitive advantage. The second step gets most of the attention in the literature and the methods are elaborated below. Step three includes all the qualitative elements that cannot be quantitated in the cash flow analysis. The forth step is making the decision, adopting it and implementing it in the new revised strategy of the company.

1.2 Estimating Cash Flows and Incremental Cash Flows

The most important and at the same time the most difficult part of evaluating an investment project, is estimating the cash flows of the project. Unfortunately, the cash flows are not just given in real life scenarios and the managers need to estimate them on basis of information collected from resources, both inside and outside the company. For complex projects this might be very difficult and errors may occur. That is why specific techniques for estimating the cash flows exist and they also take into account of the project risks. Usually many variables are involved as many departments and individuals can participate in the process. It is difficult to forecast costs and revenues associated with large, complex projects, so forecast errors can be quite significant. Further, as difficult as plant and equipment costs are to estimate, sales revenues and operating costs over the project's life are even more uncertain. That is the reason why the analysis according to Brigham (2005, p. 381) should include:

- obtaining information from various departments such as engineering and marketing,
- ensuring that everyone involved with the forecast uses consistent set of economic assumptions,
- making sure that no biases are inherent in the forecasts.

Any errors can make bad projects look good on paper. The free cash flow is the cash flow available for distribution to the investors, and the relevant cash flows for a project is the additional free cash flow that the company can expect, if the project is implemented. When identifying the relevant cash flows, defined as the specific cash flows that need to be considered in the decision, the managers abide by these two rules in order to minimize the mistakes:

- capital budgeting decisions must be based on cash flows, not on accounting income;

- only the incremental cash flows are relevant. (Brigham & Ehrhardt, 2005, p. 380).

According to Brigham (2005, p. 381) the free cash flow can be calculated as follows in equation 1:

$$\text{Free Cash Flow} = \text{NOPAT} + \text{Depreciation} - \text{Gross FA Expenditures} - \text{Change in Net Operation Working Capital} = \text{EBIT}\ (1\text{-T}) + \text{Depreciation} - \text{Gross FA Expenditures} - [\Delta\text{Operating Current Assets} - \Delta\text{Operating Current Liabilities}] \quad (1)$$

Where *NOPAT* stands for Net operating profit after taxes, *EBIT* stands for Earnings before interest and taxes and it is also called pre-tax operating profit. Equation 1 shows that the project cash flow differs from the accounting income.

Most project need assets and their purchase represents the negative cash flow. The accountants most of the time do not show the purchase of the fixed asset as a deduction of the accounting income, but the depreciation expense each year throughout the life the fixed asset. The full cost of the fixed asset also includes the costs for shipping and installing or any other related cost. The depreciation basis for the fixed asset is the full cost of the purchased fixed asset and the related cost. If the asset is sold at the end of the project it represents a positive cash flow.

In calculating the net income, the accountants subtract the depreciation from the revenues. They do not subtract the purchase price of the asset when calculation the accounting income, but the yearly charge of depreciation. So the depreciation decreases the income from taxation and this has an impact on the cash flow, but depreciation is not itself a cash flow. Therefore the depreciation must be added to *NOPAT* when estimating the project's cash flow.

In some projects additional inventory is required to support a new operation and the new sales tie up additional funds in account receivables. Payables and accruals increase as a result of the expansion and this reduces the cash needed to finance inventories and receivables. The difference between the required increase in operation current assets and the increase of operating current liabilities is the change in the net operating working capital. If this change is positive, then additional financing above the cost of the fixed assets is needed. When the used but not replaced and the receivables collected without corresponding replacements, the company will receive cash inflows and as a result the investment in net operating working capital is returned by the end of the project's life.

When a project is evaluated, the focus is on the cash flows that occur only if the project is accepted, and these cash flows are called incremental cash flows. The incremental cash flows change of the total cash flows that occur as a result that the project was accepted. In determining the incremental cash flows, the following terms need to be defined:

- the sunk costs are costs that have already occurred and are not affected by the decision of acceptance of the project. These costs should not be included in the analysis as they are not incremental costs. (Rejc & Lahovnik, 1998, p. 106).
- The opportunity costs represent the best possible return on alternative investments or the cash flows that could have been generated from an asset that the company already owns, but gave up, in order to take another course of action. This cost is therefore most relevant for two mutually exclusive events, whereby choosing one event, a person cannot choose the other. They also should not be used in the analysis of the project. (Rejc & Lahovnik, 1998, p. 106).
- The effects of the project on the other parts of the company which the economists call externalities. The additional cash flow that is as a result of a prior work of different departments of the company should be considered in the analysis. These cash flows sometimes are difficult to quantify and can be positive or negative depending on the circumstances of the project in hand. When a new project takes sales from an existing product, this is called cannibalization. Companies sometimes do not like to cannibalize their products, but it often turns out that if they don't do that as part of their strategy, the competition will. That is why when considering the externalities the full implications should be taken into account. The analysts must anticipate the project's impact on the rest of the company and use their creativity and imagination for the future growth of the company, the market segment and the economy. (Brigham & Daves, 2004, pp. 414-415).
- The term Salvage value is used for the value of assets at the end of the project. It is used for fixed asset that at end of their life still have a market value.
- The change in net working capital is defined by the expansion of business. Increased activity results in an increased need for inventory, which also increases the accounts receivable and payables. If the increase of the liabilities cannot be supported by the company, it is necessary to provide the funding difference. In the cash flow these funds are taken into account in the event that the funds are released after the completion of the project (Berk, Ločarski & Zajc, 2001, pp. 118-119).
- Interest costs are not included in the incremental cash flows because the cash flows are already discounted by the cost of capital, which includes the cost of debt.
- The environmental remediation costs are taken into account when investment required environmental remediation. Costs of environmental remediation are required in the last year of life of the investments included in cash flow investments.

The capital budgeting is straightforward when it comes to analysing if the project creates value to the company. These cash flows are also affected by whether the project is an expansion project or a replacement one. A new expansion project is a project when the company invests into new assets that will bring new sales. In this case the incremental cash flows are simply the projects cash in and outflows and the company is comparing its value with or without the project. On the other side, a replacement project is when a company replaces an existing asset with a new one. In this case the incremental cash flows are the company’s additional in and out flows that result from the new project. Also, the company is comparing its value if it takes the new project to its value with the current operations. In any case, the basic principles for evaluation of projects according to Brigham (2005, p. 390) are the same:

- Initial investment outlay which includes the cost for the fixed asset and the initial investment in the net operation working capital (hereinafter: NOWC) such as raw material, cost for shipping, assembly and etc.
- Annual project cash flow or the net operating cash flow after taxes (hereinafter: NOPAT) plus depreciation. The depreciation is added back because it’s a noncash expense and financing cost including interest are not subtracted because they are already accounted when the cash flow is discounted at the cost of capital. Also, if the project has levels of NOWC that change during the project’s life, the cash flow associated with the annual increases or reductions in NOWC must be included in the calculated annual cash flow.
- Terminal year cash flow. At the end of the project’s life, if the assets are sold by salvage value. The inflow adjusted for the taxes and any return of net operating working capital not already accounted for in the annual cash flow should be added to the terminal year cash flow.

Classification of cash flows is not always distinct as described above. The project’s cash flows can vary depending on whether the acquisition of the fixed assets is throughout the project’s life or in the beginning and if they are going to be sold in the terminal year or not. All cash flows need to be accounted for in the analysis, no matter their classification.

1.3 Break-Even Point

Break-even point is one of the possible ways of checking the investment eligibility. When investing in a new business or a new project, it is important to understand how big the profit will be and when it will occur. Break-even point is the volume of production and sales, in which total revenues equal the total costs (Tajnikar, 2004, p. 135). The break-even analysis explores the interdependence between the company‘s revenue, costs and profit at different income levels (Rebernik, 1994, p. 191). It is taken that if the selling price is the same, and respective to the sales volume, the variable unit cost are constant, as well as the structure of the sales portfolio of different products (Pučko, 2005, p. 164). The company's goal is to increase the sales over the break-even point, because at that moment the revenues exceed the costs and the company begins to generate profit. The costs can be divided into variable costs (hereinafter: VC) and fixed costs (hereinafter: FC) (Growthorpe, 2010, p. 111). The VC vary proportionately with the volume of production or the quantity (hereinafter: Q), and the FC remain independent of the volume of production, as long as there is no change in production capacity. Separating the costs to VC and FC is crucial for calculating the break-even point. The calculation of the break-even point is based on the assumption that the total costs equal the total revenues (Tajnikar et al., 2004, p. 138). Total revenues are the product of the quantities sold (Q) by the price of the product (P). Total costs are the sum of the FC and VC. VC are calculated by multiplying the average variable cost per unit of output (hereinafter: AVC) and the quantities sold. The calculation is shown in equation (2).

$$P \ x \ Q = AVC \ x \ Q + F \tag{2}$$

From equation (2) the Contribution Margin (hereinafter: CM) per unit can be calculated, as shown in equation (3).

$$Q = \frac{FC}{P - AVC} = \frac{FC}{CM} \tag{3}$$

Break-even point is simply the ratio between FC and CM per unit (Tajnikar, 2004, p. 138). Break-even point, which is expressed in the number of products the company should sell to achieve zero profit can be calculated only for companies that have a homogeneous production or only have one type of product. For companies that have a heterogeneous production, the break-even point can be calculated by the ratio between the value of the FCs and the total CM, or as expressed in the equation (4):

$$K = \frac{FC}{TR - VC} \tag{4}$$

Thus parameter K, which indicates what percentage of actual revenue (i.e. Capacity) represents the needed revenue to achieve a break-even point. The analysis of the break-even point is most often used in conjunction with an assessment of the demand. If the break-even point is lower than the amount which the market needs, the company will make a profit. If the amount of the break-even is greater than the amount that the market is prepared to accept, it is necessary to adjust the price or reduce VC. The company should take care that the adjustment should not influence too much the quality of the product (Tajnikar, 2004, p. 137).

1.4 Evaluating Capital Budgeting Projects

Every investment must be evaluated from the perspective of economic viability. The methods used to evaluate the investment projects are divided into static and dynamic. The static valuation methods do not take into account the value of money over time and are usually used as additional performance indicators of the investment. The different approaches provide various information to the decision makers, and therefore, in the process of making the decision, it is recommended to make the calculations for all methods, but not to base the decision solely on calculated indicators. In terms of economic viability of investment, the dynamic methods eliminate the shortcomings of static methods and take into account the time valuation of the money. The dynamic methods are therefore the basis for assessment of eligibility of the investment projects (Pučko & Rozman, 1992, pp. 306-307).

1.4.1 Static methods

Static methods are used for the first rough assessment of the project. They are often used in practice due to their simplicity, especially when the profitability of the investment needs to be evaluated. The most commonly used methods are the **Rate of Return** and the **Payback Period** (Kosi, 2004, p. 104). The static methods normally do not give satisfactory results on the qualities of an individual investment. They do not take into account the time value of money, the various dynamics in investing and the different rates of returns. Nevertheless, they serve as additional information on the specific qualities of investment and show data that is not reflected in the dynamic methods. An addition to these two static methods is the discounted payback period, which takes into account the time value of money (Rebernik, 1999, p. 363). All three are discussed below.

1.4.1.1 Rate of Return

The Rate of Return (hereinafter: RR) or Accounting Rate of Return (hereinafter: ARR) is the ratio between the sum of net income and depreciation (yield) and the contribution of the investment (assets) (Rejc & Lahovnik, 1998, p. 107). The ARR is calculated according to equation (5) (Brigham, 2005, p. 128):

$$ARR = \frac{Amount\ received - Amount\ invested}{Amount\ invested} \quad (5)$$

The RR calculation standardizes the return by considering the return per unit of investment. This method is very popular among managers, because it is easy and understandable and evaluates the investment in terms of profitability. The disadvantage of this method is that it is based on accounting profits instead of cash flows and it does not take into account the total return of the investment and the timing (Lumby, 1994, p. 47).

1.4.1.2 Payback Period

Payback period in capital budgeting is the period of time required for the return on an investment to "repay" the sum of the original investment. The time value of money is not taken into account. Payback period intuitively measures how long something takes to "pay for itself." Shorter payback periods are preferable to longer payback periods. Payback period is widely used because of its ease of use despite the recognized limitations described below.

The term is also widely used in other types of investment areas, often with respect to energy efficiency technologies, maintenance, upgrades, or other changes. Although primarily a financial term, the concept of a *payback period* is occasionally extended to other uses, such as energy payback period (the period of time over which the energy savings of a project equal the amount of energy expended since project inception). It can also be calculated using equation (6):

$$Payback\ period = \frac{Year\ before\ full\ recovery + Unrecovered\ cost\ at\ start\ of\ year}{Cash\ flows\ during\ year} \quad (6)$$

Equation 6 is used to calculate the earliest *payback period* or the first period after which the investment has paid for itself. If the cumulative cash flow drops to a negative value sometime after it has reached a positive value, thereby changing the payback period, this equation cannot be applied. This equation ignores values that arise after the Payback Period has been reached.

Additional complexity arises when the cash flow changes signs several times; i.e., it contains outflows in the midst or at the end of the project lifetime. The modified payback period algorithm is applied in this situation. The sum of all of the cash outflows is calculated. Then the cumulative positive cash flows are determined for each period. The modified payback is calculated as the moment in which the cumulative positive cash flow exceeds the total cash outflow.

Payback period, as a tool of analysis, can be quite useful when used carefully or to compare similar investments. As a stand-alone tool to compare an investment with "doing nothing," payback period has no explicit criteria for decision-making (except, perhaps, that the payback period should be less than infinity). It also does not consider the cost of capital, the cost for the debt or equity used to undertake the project. That is why the discounted payback period is used.

1.4.1.3 Discounted Payback Period

The payback period is considered to be a method of analysis with serious limitations because it does not account for the time value of money, risk, financing or other important considerations, such as the opportunity cost. The discounted payback period considers the time value of money by applying a weighted average cost of capital (hereinafter: WACC) discount. It is defined as the number of years required to recover the investment from discounted net cash flows. Each cash flow is divided by (1+r) t where t is the year in which the cash flow occurs and r is the project’s cost of capital.

Same as the payback period, this method for investment decisions should not be used in isolation. An implicit assumption in the use of payback period is that returns on the investment continue after the payback period. Payback period does not specify any required comparison to other investments or even to not making an investment.

The payback period and the discounted payback period do provide information on how long the funds will be tied to the project. If other things are constant, the shorter the payback period, the greater the project liquidity. Both methods are used as indicators of a project's riskiness, since the cash flows expected in the distant future are more riskier that the near term cash flows.

1.4.2 Dynamic methods

Managers in companies use these four dynamic methods for deciding on a capital project:

- Net Present Value (hereinafter: NPV),
- Internal Rate of Return (hereinafter: IRR),
- Modified Internal Rate of Return (hereinafter: MIRR),
- Profitability Index (hereinafter: PI).

These methods use the incremental relevant cash flows from each potential investment or project. Techniques based on accounting earnings and accounting rules, such as the accounting rate of return and "return on investment," are used, though economists consider this to be improper because their approach has major flaws and should not be used.

1.4.2.1 Net Present Value

After recognizing the faults of the payback period, the economists tried to find ways to improve the effectiveness of the project evaluation. The NPV represents time series of cash flows, both incoming and outgoing, and is defined as the sum of the discounted values or present values (hereinafter: PVs) of the individual cash flows of the same entity. NPV is a standard method for appraisal of long-term projects and it is widely used throughout economics, finance, and accounting. It measures the excess or shortfall of cash flows, in present value terms, above the cost of funds.

NPV is calculated as the difference amount between the sums of discounted cash inflows and cash outflows. It compares the present value of money today to the present value of money in the future, taking inflation and returns into account. The equation according to Brigham (2005, p. 349) is:

$$\mathrm{NPV} = \mathrm{CF}_0 + \frac{CF_1}{(1+r)^1} + \frac{CF_2}{(1+r)^2} + \cdots + \frac{CF_n}{(1+r)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+r)^t} \qquad (7)$$

In equation 7, the CF are the expected net cash flows at period t, r is the project's cost of capital and n is its life. If the project has a positive NPV then it generates more cash that needed to service the debt and to provide the required return to the shareholders. Therefore the managers should only approve these projects which increase the wealth of the stockholders.

1.4.2.2 Internal Rate of Return

The IRR is defined as the discount rate that gives a NPV of zero. It is a commonly used measure of investment efficiency. According to Brigham (2005, p. 351) the IRR is defined as the discount rate that equates the present value of a project's expected cash flows to the present value of the project's costs.

$$PV\ (Inflows) = V\ (Investment\ costs) \qquad (8)$$

or

$$NPV = CF_0 + \frac{CF_1}{(1+IRR)^1} + \frac{CF_2}{(1+IRR)^2} + \cdots + \frac{CF_n}{(1+IRR)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+IRR)^t} = 0 \quad (9)$$

The IRR method results in the same decision as the NPV method for (non-mutually exclusive) projects in an unconstrained environment. In most cases the 'normal' cash flow is represented when a negative cash flow occurs at the start of the project, followed by all positive cash flows. In other more realistic cases, all independent projects that have an IRR higher than the rate of return should be accepted. Nevertheless, for mutually exclusive projects, the NPV and IRR methods both lead to the same accept/reject decision. When evaluating mutually exclusive projects, especially in time and scale the NPV method should be used.

In some cases, several zero NPV rates may exist and there is no unique IRR. The IRR exists and is unique if one or more years of net investment (negative cash flow) are followed by years of net revenues. But if the project has 'non normal' cash flows where the signs of the cash flows change more than once, there may be several IRRs. The IRR equation generally cannot be solved analytically but only via iterations. In this case the NPV method should be used to complement the decision making.

One shortcoming of the IRR method is that it is commonly misunderstood to convey the actual annual profitability of an investment. This is not the case, because intermediate cash flows are almost never reinvested at the project's IRR. The actual rate of return is almost certainly lower. Accordingly, a measure called MIRR is often used.

1.4.2.3 Modified Internal Rate of Return

The MIRR is a financial measure of an investment's attractiveness and it is usually preferred to the NPV method by managers. They find the evaluation in terms of percentage rates of return intuitively more appealing than dollars/euros in NPV. The MIRR method is used in capital budgeting to rank alternative investments of equal size. As the name implies, MIRR is a modification of the IRR and as such aims to resolve two of the problems with the IRR.

The first problem is that IRR assumes that interim positive cash flows are reinvested at the same rate of return as that of the project that generated them. This is usually an unrealistic scenario and a more likely situation is that the funds will be reinvested at a rate closer to the company's cost of capital. The IRR therefore often gives an overly optimistic picture of the analysed projects. That is why for comparing projects fairly, the WACC should be used for reinvesting the interim cash flows.

The second problem, more than one IRR can be found for projects with alternating positive and negative cash flows, which leads to confusion and ambiguity. MIRR finds only one value. According to Brigham (2005, p. 357) the MIRR can be defined as:

$$\sum_{t=0}^{n} \frac{COF_t}{(1+r)^t} = \frac{\sum_{t=0}^{n} CIF_t (1+r)^{n-t}}{(1+MIRR)^n} \qquad (10)$$

$$PVofcosts = \frac{Terminal\ value}{(1+MIRR)^n} = PV\ of\ terminal\ value \qquad (11)$$

In the equations 10 and 11, the COF refers to the cash outflows or the negative cash flows or the cost of the project, CIF refers to the cash inflows or the positive cash flows and the r is the cost of capital. The left side of equation 10 represents the present value of the investment outflows discounted at the cost of capital and the right side of equation 10 represents the compounded future value of the inflows, assuming that the inflows are reinvested at the cost of capital. The compounded future value of the cash inflows is also called the terminal value or TV, shown in equation 11. The discount rate that forces the present value of the TV to equal the present value of the costs is defined as MIRR.

Taking all this in consideration, in Wikipedia (Modified internal rate of return, 2013), the MIRR is calculated as follows in equation 12:

$$MIRR = \sqrt[n]{\frac{FV\ (positivecashflows, reinvestmentrate)}{-PV\ (negativecashflows, financerate)}} - 1 = \sqrt[n]{\frac{Terminalvalue}{-PVofcosts}} - 1 \qquad (12)$$

Where n is the number of equal periods at the end of which the cash flows occur (not the number of cash flows), PV is present value (at the beginning of the first period), FV is future value (at the end of the last period).

The equation adds up the negative cash flows after discounting them to time zero using the external cost of capital. Then it adds up the positive cash flows including the proceeds of reinvestment at the external reinvestment rate to the final period, and finally calculates what rate of return would cause the magnitude of the discounted negative cash flows at time zero to be equivalent to the future value of the positive cash flows at the final time period.

NPV and MIRR will lead to the same decision when analysing two mutually exclusive projects of equal size and same life. If the projects are of equal size and differ in lives, the MIRR will always lead to the same decision. If the projects differ in size, then conflicts can still occur. The MIRR is superior to the IRR as an indicator of the projects true rate of return or expected tong term rate of return, but the NPV method is still the best way to choose among competing projects because it provides the indication how much each project adds to the value of the company.

1.4.2.4 Profitability Index

Another method used to evaluate projects is the PI. According to Brigham (2005, p. 359) it is calculated as:

$$PI = \frac{PV\ of\ future\ cash\ flows}{Initial\ cost} = \frac{\sum_{t=0}^{n} \frac{CF_t}{(1+r)^t}}{CF_0} \tag{13}$$

Where the $\mathrm{CF_t}$ represents the expected future cash flows and the $\mathrm{CF_0}$ represents the Initial cost. The PI shows the relative profitability of the analysed project or the present value per dollar/euro of initial cost. A project is acceptable if the PI is greater than 1.0 and the higher the PI, the better the project ranking.

Mathematically NPV, IRR, MIRR and PI lead to the same accept/reject decision when analysing independent projects. If the NPV is positive, the IRR and MIRR will always exceed the rate of return r, and its PI will always have a PI greater than 1.0. However, the method gives conflicting rankings for mutually exclusive projects.

1.5 Estimating Risks

The cash flows are discounted by the cost of capital, and the cost of the capital is the weighted average of the costs of debt, preferred stock and common equity, adjusted for the project’s risk. (Brigham, 2005, pp. 308-309). The WACC is the rate of return that satisfies the company stockholders, investors and debtors. The interest payments should not be subtracted when estimating the project's cash flows. The cost of debt is already included in the WACC, so subtracting it again leads to double counting of the interest costs. WACC is calculated using the following equation:

$$WACC = w_d r_d(1 - T) + w_{ps} r_{ps} + w_{ce} r_s \qquad (14)$$

In equation 14, the w_d, w_{ps} and w_{ce} are the weights used for debt, preferred and common equity, respectively. Also, r_d is the cost of debt before tax, r_{ps} is the cost of preferred stock, the r_s is the cost of shares or common equity and T is the tax.

WACC is the return that a company must earn from the existing resources to justify the interests of lenders and owners. The retained earnings belong to the owners as compensation for the use of the capital. Sometimes the calculation of the WACC is very complicated and some of the parameters are estimated. Therefore, some scholars believe that in the evaluation of the cost of financing, it is better to define the WACC as a range, rather than an accurate assessment.

The cost of equity and debt funding are measured differently. The cost of equity is generally determined by the Capital Asset Pricing Model (hereinafter: CAPM) and the principle of opportunity cost needs to be taken into account. The after tax component of the debt $r_d(1 - T)$ is the interest rate on the debt or the average interest rate charged by banks on loans, less the tax savings that result because interest is deductible. We measure the expected cost of new capital, so it is necessary to apply the necessary market share value without carrying about the relationship between equity and debt (Brealey & Myers, 2000, p. 544). The market value of the individual parameters can be stated in several ways:

- Market capitalization for publicly traded companies, the market price per share multiplied by the number of shares issued.
- If the company borrowed by issuing bonds, the market value of the debt is determined by the market value of bonds.

In case of bank loan, the market value of the loan is equal to its book value. When defining the expected capital cost it is reasonable to consider targets, because they are the best estimate of how the company should continue to be financed on common stocks (Brigham, 2005, p. 322). Many factors influence the cost of financing. Factors which the company can control, like the structure of the financing or their dividend and investment policies. The structure of financing affects the cost of equity capital, since the beta coefficient depends on leverage and because the cost of debt after tax is lower than the cost of equity. The company can reduce the $WACC$ if it decides that it has less equity and more debt. The increase in debt leads to a higher risk of both debt and equity, and results in an increase WACC. Also, the dividend yields are affected by a higher required return. The company, which pays a large proportion of the net profit for funding its operations, has a big likelihood to issue new shares or borrow again. This creates additional costs of issuing shares or borrowing.

The company cannot affect factors such as the level of interest rates, the market risk premium and the tax rates (Brigham, 2005, p. 323). The calculated cost of funding reflects the risks of the existing resources in the society. In most cases, new investments similar to the existing one have the same level of risk. The companies, which start with a completely new activity, have different risk level and respectably different WACC.

1.5.1 Risk management

Risk is part of business decisions and therefore is related to the future of the company or the project. Risk can be defined as the likelihood that the real business results deviate from the expected business results.

In theory, when making the investment decision, it is presumed that the company already has all the necessary information or is fully informed, and operates in conditions of complete certainty (Tajnikar, 2004, p. 15). In practice, the company rarely has all the information available, so it operates under conditions of incomplete information. This leads to uncertainty in the moment of making the business decisions. We can say that the decision in such situation is a risky decision. Risk can also be defined as the potential risk of unforeseen events that may occur in the future, where the consequences could have a negative impact on the success of the project (Peterlin, 2003, p. 209). There are the three types of risks (Brigham & Dave, 2004, p. 317):

- stand-alone risk or the independent risk of new investments,
- corporate risk or the risk of new investments within the enterprise,
- market risk.

The company's management should analyse and respond to the uncertainties associated with the investment project. Risk assessment of investment projects are made in terms of general economic indicators like the general economic trends on the market or possible recession, like the risk due to cyclical economic activity, risk due to interest rates and inflation and other more specific risks like the currency risk, credit risk, etc. It is necessary for the company to first identify the exact sources of risk and leverage them. That is why one of the most important concepts to reduce risk is diversification. With this concept, the investment risks are categorized in a number of areas that do not have the same success factors. By diversifying the risk in the portfolio, the company provides a basis for a creation of an appropriate investment structure in terms of risk, return and liquidity (Filipič & Mlinarič, 1999, pp. 177-184).

1.5.2 Sensitivity analysis

Sensitivity analysis is probably one of the most commonly used risk analysis (Brigham & Ehrhardt, 2005, p. 398). It is based on determining the acceptability of the project if its most important variables change.

The essence of this method is that for each investment project it evaluates several possible outcomes which are expressed in different levels of net cash flow. The different levels of net cash flows are affected by changes of one of the strategic variables, for example: sales volume, sales price, variable and fixed costs, cost of materials, labour costs, project construction time and capital costs, etc. The analysis should cover the most likely optimistic and pessimistic projections of the net cash flows (Filipič & Mlinarič, 1999, p. 175). By making this analysis the company learns about the risk factors that are most affected by the change in one parameter. By identifying these critical factors the company can focus more on them and take actions to manage them.

2 COGENERATION AND TRIGENERATION

The third chapter is an overview of the concept of cogeneration and trigeneration. I make a comparison between conventional heat/cool/electricity production and the ecological benefits of using cogeneration or trigeneration. I make a summary of the latest EU legislation regarding the initiatives to increase the percentage of renewables in the share of produced energy. The chapter will cover the market conditions in the energy sector and the gas prices in the world and the conditions in the energy sector in Macedonia.

Cogeneration and trigeneration are concepts that are more frequently mentioned in recent years in energy circles because of their energy efficiency. In fact, the cogeneration or combined heating and power (hereinafter: CHP) process is a very old and proven method for energy efficiency, which was unfortunately all too often neglected in an era of intense energy. The essence of the process is achieving high efficiency of the primary energy source combined with power generation. This high efficiency is achieved in the process of converting the primary energy source to electricity and also by putting into use the heat that is a by-product of the conversion. All traditional sources of electricity generation use as primary source fossil fuels or biomass to produce electricity and in the same time they also produce and release large quantities of heat. The conventional power plant, whose primary energy source is some fossil fuel, usually does not use the heat as a by-product, but it is discharged into the atmosphere. In cogeneration power plants, this thermal energy has a useful application in the production process for heating. CHP technology reduces the consumption of non-renewable primary resources, the environmental impact and the total cost of energy services.

Trigeneration or CHCP is the process by which some of the heat produced by a cogeneration plant is used to generate cooled water for air conditioning or refrigeration. An absorption chiller is linked to the CHP to provide this functionality. The main advantages of building a trigeneration system according to Goodell (2003) are:

- The trigeneration system reaches system efficiencies of up to 92% - around 300% more efficient than conventional power plants that average around 28% - 35%, and combined-cycle cogeneration power plants are about 60% efficient.
- Significantly reduces environmental impact compared to typical fossil fuel based power plants, including the elimination of net greenhouse gas additions to the environment.
- May save enough money through increased energy efficiencies for the new system to be paid in as little as a few years (depending on existing electric rates, load profile and thermal demand).
- Reduces demand of power from the electric grid.
- Eliminates black-outs and other power interruptions.
- Decreases the dependence on foreign oil.

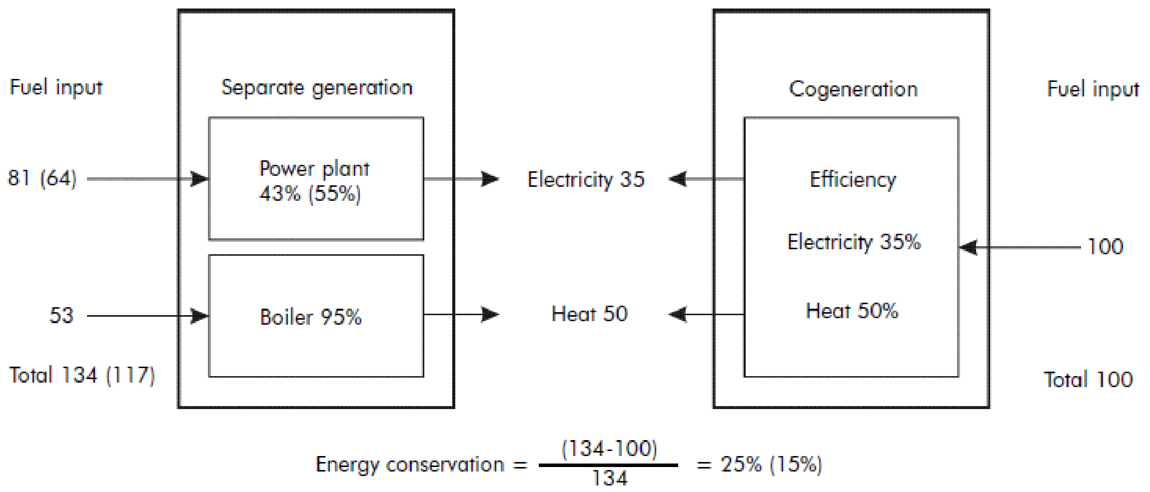
If the input fuel is competitively priced, the trigeneration process is competitive with all other forms of renewable and non-renewable energy production. In practice, the most common cogeneration plants are the urban heating plants or the district heating systems. In these facilities dominates the installed capacity of cogeneration, which during the heating season is the guaranteed off-take of heat, while part of the electricity is consumed in these buildings for own use, and the surplus is fed into the electricity grid.

- **Comparison with conventional heat/cool/electricity production**

When analysing the investment in a trigeneration system, it is interesting to see how the construction of a trigeneration power plant differs from the conventional energy supply system. Cogeneration and trigeneration are presently the most important available means of improving energy efficiency. According to Smith (2006) an average cogeneration unit has an efficiency of up to 85% so only 15% of the energy initially used (fuel) is lost. In Smith's study a comparison has been made of a modern electricity plant with a combined cycle of steam and gas turbine that has an efficiency of 55%, meaning that 45% of the energy is lost.

In Figure 1, the cogeneration plant is compared with conventional production plants of electricity and heat. It shows that the separate production of heat and electricity requires more fuel, or total input of 134 compared to the cogeneration total input fuel of 100 of amounts to produce the same amounts of heat and electricity. The figure shows a realistic electrical efficiency of 35% and a thermal efficiency of 50% for the cogeneration plant. The amount of energy saved on efficiency, depends on the separate efficiencies of the electricity and heat generation plants against which the comparison is made. The figure assumes the average energy efficiency for a typical electricity production infrastructure to be 43%, and for the boiler efficiency of 95%. Comparison against a modern combined-cycle electricity plant with an energy efficiency of 55% yields the energy conservation figures given in brackets.

Figure 1: Cogeneration Compared to Separate Generation of Electricity and Heat



Source: R. Smith, *Distributed generation and renewables*, *2006*, p. 2, Figure 1

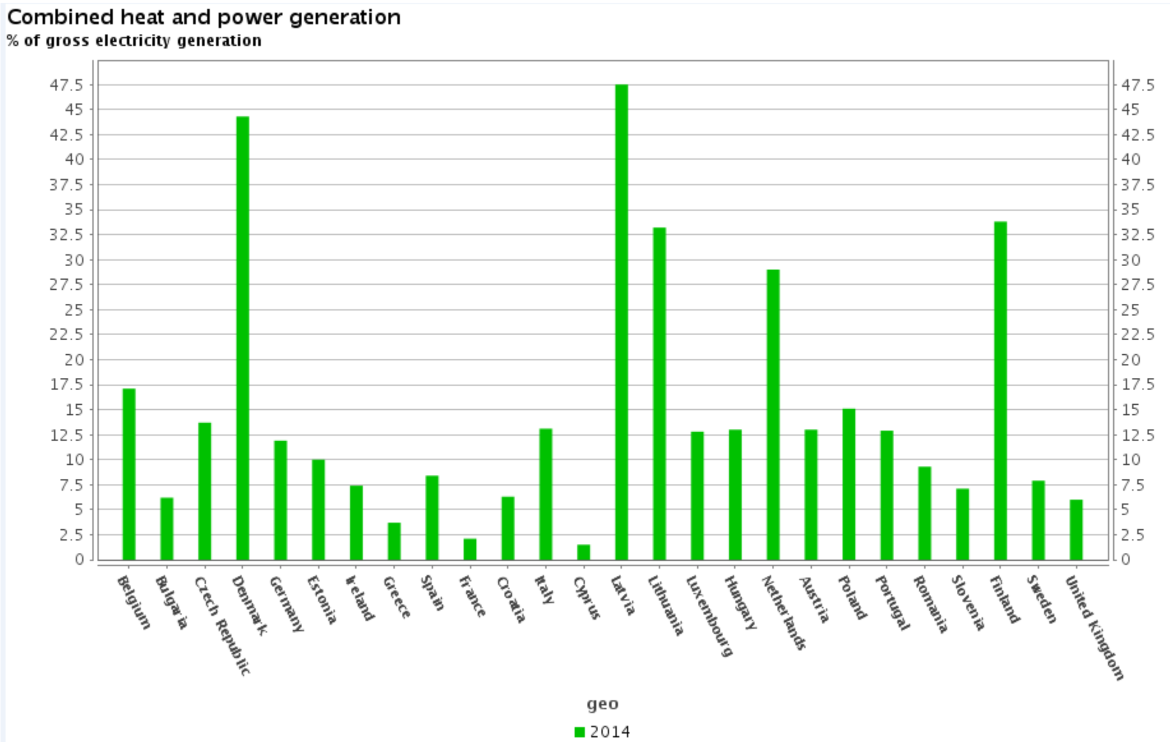
As indicated in Figure 1, the use of cogeneration plants leads to an energy efficiency improvement of 15 to 25%. If a trigeneration plant was used the efficiency percentage will only increase even more. That is why the main driver behind the success of cogeneration and trigeneration is the need for improving the efficiency of the used input fuel.

2.1 Policy and Regulations in EU

Cogeneration and trigeneration are widely recognized in the EU's energy supply, and at present contribute with more than 10% of the electricity generated. Across the EU there is considerable diversity in both the scale and nature of cogeneration development. Figure 2 shows the percentage of electricity produced by cogeneration in the gross electricity production of the EU countries according to Eurostat for the year 2014. This diversity reflects the differences in history, policy priorities, natural resources, culture and climate, and is closely related to the structure and working of the electricity markets.

Figure 2 shows that the use of cogeneration in different countries varies from a few percent of overall production in Cyprus to 47.5% in Latvia. In the countries with a high share (Denmark, Finland and Latvia) clear policy incentives have boosted the application of cogeneration. For instance, in the Netherlands, a special low gas price and a fair tariff guarantee for cogenerated electricity supplied to the grid led to considerable growth in cogeneration between 1990 and 2000. However, special tariffs for the cogeneration market are no longer possible and only cogeneration plants that have consumers for the produced heat can survive in the liberalized market.

Figure 2: Generated Electricity from Cogeneration in the EU 2014



Source: Eurostat, *Combined heat and power generation for 2014*, 2016

In 1997 the European Commission published 'Strategy to Promote Combined Heat and Power, which set targets for cogeneration in member states. According to the Commission, the scope for cogeneration is not being fully utilized and it therefore wants to promote high-efficiency cogeneration based on the useful heat demand. The Directive promoted cogeneration in Directive 2004/8/EC amending Directive 92/62/EEC, popularly better known as the 'Combined Heat and Power (CHP) Directive'. The directive entered into force in February 2004 and member states have been obliged to begin its implementation since 2006 but due to delays resulting out of the comitology process, member states had to adopt the first obligations of the directive by 6 August 2007.

The aim of this Directive is as follows: *"The purpose of this Directive is to increase energy efficiency and improve security of supply by creating a framework for promotion and development of high efficiency cogeneration of heat and power based on useful heat demand and primary energy savings in the internal energy market, taking into account the specific national circumstances especially concerning climatic and economic conditions."*

The key features of this Directive, which has to be implemented by the EU member states, are the following:

- A system of guarantee of origin (certificates) for cogenerated electricity has to be established.
- Member states have to analyse the national potential for cogeneration.
- Member states have to report every four years on the progress made towards increasing the percentage of energy production accounted for by cogeneration.
- Support schemes for cogeneration have to be based on useful heat demand and primary energy savings.

It is intended that the directive will have a significant impact on the legislation and the dispersal of CHP and district heating within the member states of the EU. The Commission believes that this anticipated growth has to be reached and if possible exceeded. A significant effort is required to achieve these results. According to analyses made, doubling of the current share of CHP from 9% to 18% of the total gross electricity generation in the EU member's states, produced with CHP plants by the year 2010, is realistically achievable. The Commission saw the cogeneration of heat and power (CHP) as an important contributor to the realization of the EU's Kyoto targets. This would imply doubling the existing installed CHP electrical capacities and increasing the annual load factor by 30%. It would also require Member states to remove various obstacles to enable greater penetration of CHP in their energy systems.

The use of CHP presents a substantial potential for increased energy efficiency and reduced environmental impacts. After the directive was signed, it became a priority area for many EU member states. The efficient use of fuel in simultaneous production of heat and power can offer energy savings and avoid CO_2 emissions compared with separate production of heat and power. Further, the development in the use of fuels used in CHP applications shows a trend towards cleaner fuels. Other EU policy developments that are important for the further development of CHP in Europe are:

- The system of emission trading in carbon dioxide (CO_2). Since CHP contributes to a reduction of CO_2 emissions, trade in CO_2 credits can promote the use of CHP.
- The EU's energy policy will place considerable emphasis on energy efficiency in the coming years as stated in the energy performance of buildings Directive (2002/91/EC). This Directive had to be implemented in EU member states' national legislations by 2006. It calls for harmonized principles for the determination of the energy performance of buildings, minimum requirements for this energy performance and the certification of energy performance. CHP (especially small-scale) can play a role in meeting these requirements.

• The Directive on energy end-use efficiency and energy services (2006/32/EC, 5 April 2006).

In 2006, a new EU Directive was developed for promoting the use of renewable heat (e.g. heat from a biomass CHP unit). In the White Paper "An Energy Policy for the European Union" the European Commission committed itself to present a strategy offering a coherent approach for the promotion of Combined Heat and Power (or CHP) in the EU. This initiative is to ensure the necessary co-operation between the Community, its Member States, utilities and consumers of electricity and heat to assist in dismantling barriers to the development of this environmentally friendly and energy saving concept.

On 25 October 2012, the EU adopted the Directive 2012/27/EU on energy efficiency. This Directive established a common framework of measures for the promotion of energy efficiency within the Union in order to ensure the achievement of the Union's 2020 20% headline target on energy efficiency and to pave the way for further energy efficiency improvements beyond that date. It lays down the rules designed to remove barriers in the energy market and overcome market failures that impede efficiency in the supply and use of energy, and provides for the establishment of indicative national energy efficiency targets for 2020. The targets adopted the Directive 2012/27/EU for 2020-2050 are (Energy, 2015):

- Reducing greenhouse gases by at least 20% compared to 1990 levels,
- 20% of the energy produced in EU to be from renewable sources,
- 20% increase of the energy efficiency.

The targets for 2030 until 2050 are:

- Reducing greenhouse gases by at least 40% compared to 1990 levels,
- 27% of the energy produced in EU to be from renewable sources,
- 27-30% increase of the energy efficiency,
- 15% electricity interconnection (i.e. 15% of electricity generated in the EU can be transported/sold to other EU countries).
- The target for 2050 is to reduce the greenhouse gases by 80-95% compared with 1990 levels.

2.1.1 Policies and regulations in Macedonia

Macedonia has also adopted Directive 2009/28/EC (Energy community, 2016). Macedonia agreed to submit the revised National Renewable Energy Action Plans (hereinafter: NREAP) to the Secretariat by June 30, 2013. The adoption plan was prepared in accordance with the template published by the European Commission. In general, the adoption plan maps down the expected legally binding targets that Macedonia needs to reach in the renewable energy sector by 2020. The efforts for energy sector reforms in Macedonia were jeopardized by the amendments to the Energy Law in October 2014. With the new amendments customers were denied the right to choose their supplier.

In 2015, Macedonia failed to transpose Directive 2009/28/EC on time. In the NREAP document submitted to the EU Secretariat in January 2016, the Macedonian government stated that Macedonia will not meet the mandatory 28% renewable energy target in 2020 but in 2030. This statement was not in line with the commitments taken by the country at the Ministerial Council in 2012. A key precondition in this respect is to review the energy statistics data on biomass consumption based on the latest survey and to include adequate measures to achieve the national target in 2020. In the last years, the Macedonian government took steps to remove some of the barriers related to administrative procedures like authorization, urban planning and property issues. Deadlines are shortened and unnecessary procedural steps have been abolished. However, there are still no clear mechanisms for coordination between the different authorities. Authorisation, certification and licensing rules are not always objective and non-discriminatory in practice. The creation of a one-stop shop for all permit applications is envisaged in the future without specific timeline for implementation. As next steps, the availability of information for interested parties has to be further increased. (Energy community, 2016)

2.2 Ecological Effects

In addition to improving efficiency trigeneration offers various other potential benefits. The most important are:

- If all the heat produced can be used on the production site, cogeneration or trigeneration is the cheapest way to produce electricity.
- The use of trigeneration leads to lower emissions to the environment, especially of CO2.
- Local production of electricity can improve the local security of the electricity supply.

The investor should always make an analysis considering the different fossil fuels as energy source of the power plant. The input fuel for the trigeneration plant can be lot of energy sources – solar systems, wind for wind-powered production units, heavy fuel, fuel, wood biomass, waste biomass, etc. The system can vary in complexity and even consolidate more than one input energy sources, depending on the geolocation of the facility. For instance, if there are not enough sunny days or enough wind speed all these possible scenarios are not the best solutions for the investor. Also, in addition to the geolocation, the available location area of the facility, the possibility of transporting the equipment and connection to the electricity network, the dimensioning of power facility, the prices of the fossil fuels or the amount of the investment can be show stoppers. The investor has to have all the information about these possibilities before making the decision about the input fuel.

In our case, the location of the power plan is in the centre of the city of Skopje, and should be an integral part of the shopping mall. That is why some of the possible scenarios like the solar systems, wind, wood, crude oil and waste biomass for input fuel immediately have to be excluded.

Let‘s analyse the ecological impact that the input fuel causes. The smog is one of air pollutants. According to the website Wikipedia (Smog, 2016), smog can be present in the lowest ozone layer above the earth and is formed from chemical reactions of carbon monoxide, nitrogen oxides, organic components and heat from the sun. The increased use of natural gas in the production sector of electricity, its replacement as fuel for vehicles, or increased use of natural gas for industrial purposes, can significantly contribute to the fight against industrial smog, especially in urban centres where it is most needed.

Acid rain is a problem in the environment that occurs in industrialized areas worldwide, damaging the forests and wilderness and also causing respiratory and other diseases in humans. Acid rain is formed when sulphur dioxide and nitrogen oxides react with water vapour and other chemicals in the presence of sunlight. They form various acidic compounds in the air. The main cause for the creation of acid rain pollutants sulphur dioxide and nitrogen sulphide is the burning of coal used in energy and industrial centres.

Utilization of natural gas to meet the energy needs of industrial boilers and other technological processes and for producing electricity significantly reduces emissions. Natural gas is becoming a very important, effective and competitive fuel whose increased use enables reducing emissions of harmful air pollutants. Plants that use coal are one of the biggest air polluters, with highest emissions of SO_2, CO_2, and NO_X. In fact, only 3% of the emissions of SO_2, 5% of the emission of CO_2 and 2% of NO_X are coming from non-coal plants that generate electricity.

With combustion of natural gas used to produce electricity, boilers and other industrial consumers emit low levels of NOx and CO_2 emissions and almost no SO_2 emissions. Natural gas can be used instead of other fossil fuels such as coal, oil, petroleum or coke, which emit significantly higher levels of pollutants and reduced ashes. Coal power plants that use filters on the industrial boilers to reduce SO_2 emissions, also produce thousands of tons of hazardous sludge. Because the burning of natural gas emits very low emissions of SO2 it eliminates the need for brushes and reduces quantities of sediment or sludge. In case of re-burning, a process that involves the injection of natural gas in coal or oil boilers, the fuel mix can result in reductions of NOx emissions from 50 to 70% and for SO2 emissions reduction of 20-25%.

In the last decade new technologies have emerged for the exploitation of natural gas and other gases as a fuel for production of electricity. Newest fuel cells are sophisticated devices that use hydrogen to produce electricity, similar to a battery. Although they are still in development, widespread consumption of fuel cells can significantly reduce emissions associated with electricity production.

Essentially, electricity generation and industrial applications that require electricity, all exploit the flammability property of the fossil fuels. Because of its clean burning nature, the use of natural gas, alone or in combination with other fossil fuels, helps reduce the emission of harmful pollutants. In our case, the investor made a correct decision to use natural gas as an input fuel, due to environmental reasons and the geolocation of the plant.

2.3 Market Conditions in the Energy Sector Worldwide

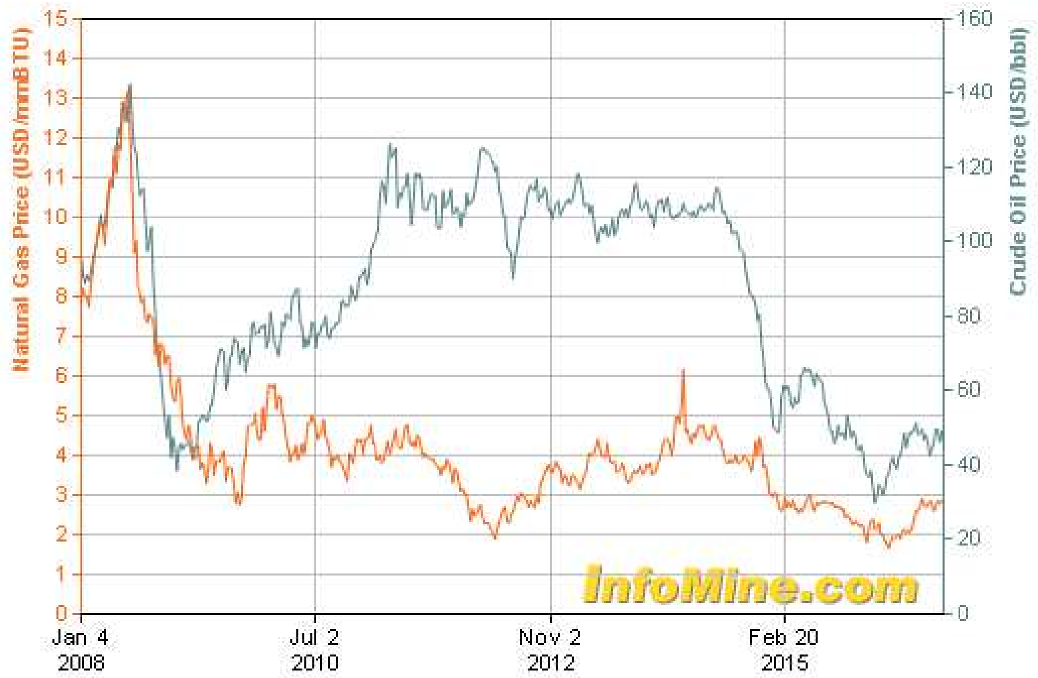
Because the investor will choose natural gas as an input fuel, we need to analyse whether natural gas is the right fuel for the future. The first point that needs to be understood when analysing the market conditions in the energy sector is the volatility of gas prices, and how it influences the total investment costs. According to energy experts, the price of gas contains a number of paradoxes (Wall Street Journal, 2016). The volatility of prices is a potential obstacle for rapid development. Weak economic conditions in the U.S. and around the world in 2008 and into 2009 led to less demand, which helped push prices of gas down. Until 2012 the gasoline demand has dropped to a 12-year low, but the consumers were paying the highest-ever prices. The reason behind was the rising global oil prices.

The prices for gasoline, diesel and heating oil are determined by global demand and worldwide crude prices. With the worldwide economic recovery underway, demand is on the rise again, but conflicts in the Middle East and North Africa have put supplies at risk. This combination of rising demand and reduced supply helped push prices higher over the last few years. Until 2014, the prices of crude oil were above the 100 USD/barrel. However, the recent downturn in prices was the result of growth in oil supplies, largely from the U.S., outpacing the growth in global demand.

Crude oil prices are set globally through the daily interactions of thousands of buyers and sellers in both physical and futures markets, and reflect participants' knowledge and expectations of demand and supply. In addition to the economic growth and geopolitical risks, other factors, including weather events, inventories, exchange rates, investments, spare capacity, OPEC production decisions, and non-OPEC supply growth all factor into the price of crude oil. The world's demand for oil increased sharply for several years. The Energy Information Administration expects growth to continue over the next couple of years reaching 93.8 million barrels per day in 2015 and 95.2 million in 2016.

The National Petroleum Council (2008) examined a broad range of the global energy supply, demand and technology projections through 2030 and concluded that "the world is not running out of energy resources, but there are accumulating risks to continuing expansion of oil and natural gas production from the conventional sources relied upon historically." These risks include political instability in the Middle East and North Africa, the resurgence of resource nationalism in Latin America, civil unrest in Nigeria, piracy off the African coast, transit vulnerability in the Caspian/Ukraine, energy subsidies in Asia, extreme weather around the world, and restricted access to resources in the U.S. These risks create significant challenges to meeting projected energy demand.

Figure 3: Price Comparison between the Natural Gas and the Crude Oil, 2008-2016



Source: Infomine, *Chart Builder*, 2016

A historical price comparison is generated between the prices of crude oil (in USD/barrel (hereinafter: USD/bbl)) and natural gas (in USD/ million British thermal units (hereinafter: USD/mmBTU)) (Infomine, Chart Builder, 2016). The high volatility of prices in the period from January 2008 till September 2016 is visible on Figure 3.

The increase of prices is not good for the gas economy because it leads to distrust among consumers, which reduces investments in new facilities to produce electricity. It also reduces the competitiveness of natural gas compared to other fuels, and therefore this uncertainty leads to selection of different input fuels. In the United States, and in Europe, gas prices depend on the price of oil, but for production of electricity, oil is not always the best choice. A comparison between the prices of crude oil (in USD/barrel) and natural gas (in USD/mmBTU) for the last 12 months is shown on Figure 4.

Figure 4: Price Comparison between the Natural Gas and the Crude Oil, 2015

Source: Infomine, *Chart Builder*, 2016

As seen on Figure 4, the price of natural gas in the last 12 months is far less volatile compared to the price of crude oil. Since 2014, the price of natural gas has declined, but due to the increasing demand it is rising again and following the price trend of crude oil. In the last year, the price of gas did not decrease as much as the price of crude oil so, at the moment, gas is a relatively more expensive fuel than crude oil.

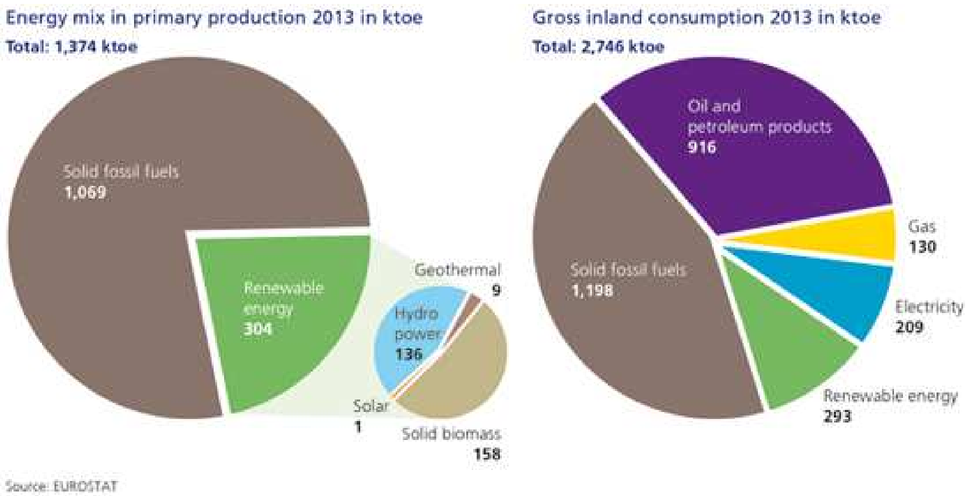
On June 26 2016, the UK public voted to leave the EU, marking the beginning of the end of the 43 year relationship. The news increased the British gas contract for next-day delivery and next-month delivery by about 1p/th, while prices in mainland Europe gas markets moved in the opposite direction. According to the website ICIS (British-nbp, 2016), the British NBP gains came as the British pound (GBP) slumped to a 31-year low against the US dollar and was more than 6% down on the Euro. This event gave euro-backed traders an incentive to buy GBP-denominated contracts, which helped to bolster National Balancing Point (NBP) products. The NBP Virtual Trading Point is operated by the UK National Grid, the transmissions system operator for natural gas in the UK. The vote, which came as a surprise to many participants, imitated a period of uncertainty for the British energy market and the world economy as a whole. Another impact of the vote has been the weakening of the oil benchmark and oil prices have dropped almost 3%. At the moment it is too early to discuss the long term effects of this vote, but uncertainty continues to grow.

In Germany, the indicator of profit margins for gas-fired plants that do not include the cost of carbon has improved recently, but still the economic prospect of continuous gas-fired generation of electricity remains well out of sight. The few companies that plan new gas powered plants in Germany see profit opportunities mostly on short-term markets or working as reserve capacity. Most upcoming larger gas-fired plants that are due to participate on the market will also produce heat because co-generation receives subsidies in Germany.

2.4 Market Conditions in Macedonia

Having in mind that out project is in Macedonia, the market conditions in the energy sector in Macedonia need to be analysed. This means getting an overview on how the market and the operations for the natural gas, electricity and heating are organized. These energy segments in Macedonia have their specifics explained below and at the moment are not meeting fully the promises of the implementation of the Energy commission's Directive 2009/73/EC.

Figure 5: Energy Mix in Primary Production and Gross Consumption from 2013 in ktoe



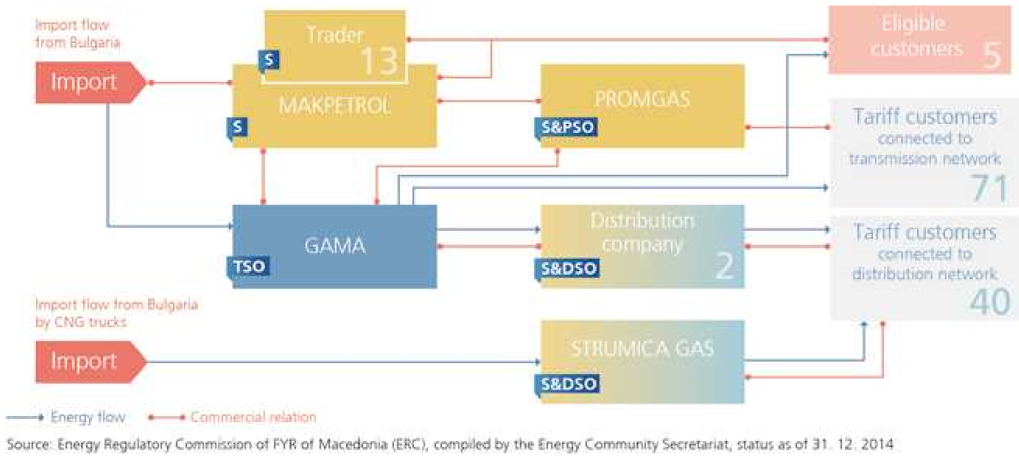
Source: Energy community, FYR Macedonia, 2016

Figure 5 shows the energy mix in 2013 from primary production in the energy facilities in Macedonia in kilotonne of oil equivalent (hereinafter: ktoe). Also the figure shows the gross consumption in 2013 of the different energy carriers in Macedonia throughout 2013. Figure 5 shows that the energy from renewable sources takes 22% from the national production, mostly from solid biomass (50%), followed by hydro power, solar and geothermal plants. When it comes to consumption, the solid fossil fuels that fuel thermal power plants in Macedonia take the biggest percentage, followed by oil and petroleum products used in the industry. Renewable energy, electricity and gas have a share of approximately 22%. This means that introduction of CHP plants would have a significant environmental impact by increasing the renewable segment in the overall energy structure.

2.4.1 Natural gas market in Macedonia

In Macedonia, the company GAMA AD performs the activity of transmission and management of the system for transmission of natural gas, provides planning, construction and maintenance of the pipeline, the measuring-regulatory stations and other equipment. GAMA is under joint control of the State and Makpetrol, the biggest gas importer and supplier. The operation of this vertically integrated company does not comply with the unbundling requirements of Energy commission’s Directive 2009/73/EC. The distribution scheme of the Natural gas in Macedonia is shown on Figure 6.

Figure 6: Distribution Scheme of Natural Gas in Macedonia



Source: Energy Community Secretariat, Energy Regulatory Commission of Macedonia, *Distribution scheme of natural gas in Macedonia*, 2014.

There are three smaller systems for the distribution of natural gas, the Directorate for Technological Industrial Development Zones, PE Kumanovo Gas and PE Strumica Gas. These companies are holders of licenses for energy activities of natural gas distribution and supply of natural gas to customers connected to the distribution system of natural gas and ensure the development, maintenance and safe and secure operation of the distribution system, and reliable delivery of natural gas to customers. Starting from January 1st, 2015, the natural gas market in the country is fully liberalized and all customers can choose from which distributer they will purchase natural gas.

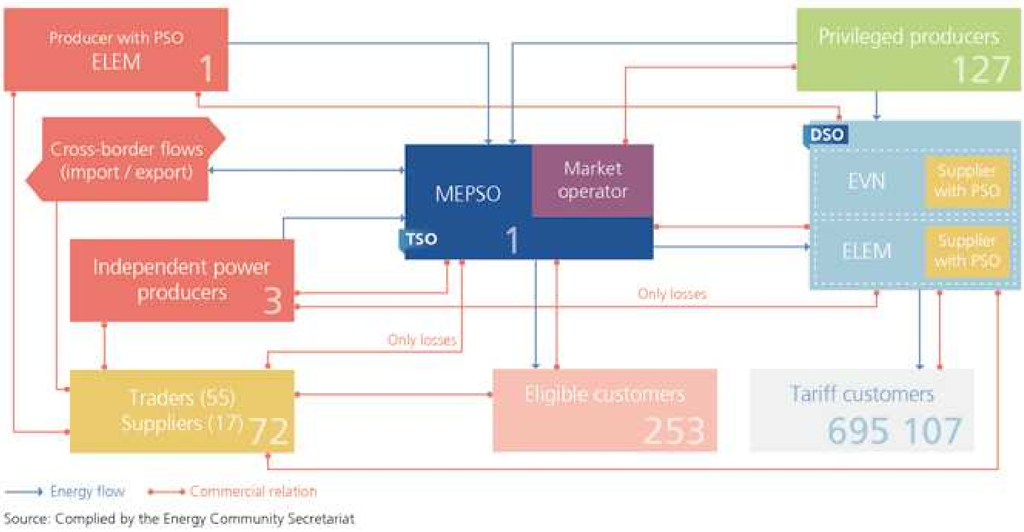
There is no domestic gas production in Macedonia. Almost the entire consumption, approx. 140 mcm per year, is imported from Russia through the only entry point at the Bulgarian border. Natural gas is mainly consumed for electricity and heat production and by industrial customers. Households have only a very small share of consumption. The distribution network in the city of Strumica, in the South of the country, is not connected with the transmission network at all and supply is ensured by truck transport of compressed natural gas (CNG) from Bulgaria.

2.4.2 Electricity market in Macedonia

The electricity market in Macedonia is regulated and the sale of electricity and capacity is carried out at prices and conditions approved by the Energy Regulatory Commission. Agreements between participants of the regulated part of electricity market are subject to approval by the Energy Regulatory Commission. The participants in the regulated electricity market, shown in Figure 7, are:

- the electricity power plants (AD ELEM - Skopje),
- other preferential power plants,
- supplier of electricity for tariff customers, as of December 31, 2014 (EVN Macedonia AD - Skopje),
- electricity transmission system operator (AD MEPSO - Skopje), and
- operator of the electricity market for buying and selling electricity generated by preferential electricity (AD MEPSO - Skopje).

Figure 7: Macedonia's Electricity Market Scheme



Source: Energy Community Secretariat, *Macedonia's electricity market scheme*, 2016.

In the unregulated electricity market, the sale of electricity and capacity is carried out at prices and conditions freely negotiated between buyer and seller, of their choice, risk and expense. All household customers and more than 99.9% of all non-household customers are connected to the distribution system of EVN Makedonija. The company also supplies 98% of electricity to the customers under regulated prices. EVN's and ELEM's licenses for supplying customers at regulated prices expired in December 2014. Macedonia has missed the deadline for implementation of the Third Package by January 1st, 2015 (Energy community, 2016). Amendments to the Energy Law in October 2014 entailed several instances of non-compliance with the Treaty, including impediments to market opening, suspension of already existing eligibility right and prevention of regional market integration. According to the Treaty, excessive price regulation, such as wholesale price regulation, must be eliminated without delay. Public service obligations should only be applied as a tool for overcoming market failure and not as an instrument to obstruct the developments of markets.

Particular rules regarding taking renewable energy into consideration in the transmission and distribution network development planning are not in place. Principles for access to the networks and operation of the grids for renewable energy producers still have to be transposed in primary legislation. The Distribution Grid Code has been amended to introduce a chapter for the connection of renewable energy installations to the distribution network. To comply fully with Article 16 of Directive 2009/28/ EC, MEPSO and EVN as network operators also have to become more transparent towards the producers of renewable energy with regard to information on the estimated costs and timeframe for connections. ERC has to ensure that rules for connection and access to the networks are implemented in a non-discriminatory and objective way for private and state companies, as there are cases of doubt in this project. With the decisions of the ERC, small customers and households are prohibited to switch supplier which is a breach of the Treaty. This right instead of January 1st, 2015 has been postponed until 1 July 2020. In January 2015 the Energy Community Secretariat opened an infringement procedure against Macedonia for its failure to comply with the Energy Community's eligibility rules.

In June 2016, MEPSO signed the agreement to become cofounder and co-owner of the South East European Coordinated Auction Office (SEE CAO). SEE CAO is a regional auction house that is founded by 8 transmission system operators in order to facilitate cross-border electricity trade. They organize auctions for leasing power line capacity for cross-border electricity transmission. The first Macedonian border where the SEE CAO will begin to organize auctions is the FYR Macedonian-Greek border. Annual, monthly, and daily auctions on this border are expected to begin early in 2017. With this agreement MEPSO realized one of the commitments undertaken with the ratification of the Treaty establishing with the European energy community. For some, primarily state-owned companies, procuring in the competitive market has proven cumbersome as the Public Procurement Law obliges them to purchase electricity through tender procedures. Thus, mandatory and lengthy public procurement procedures implicitly impede market opening. At the moment there are only a few cogeneration power plants in Macedonia, but they are used as a reserve for a very low number of hours, which is why they are not efficient or profitable. This is the reason the prices for production of electrical, heat or cooling energy are not clearly defined or regulated by the Regulatory commission. The prices considered in the calculations are best estimates or the market prices at the moment.

2.4.3 Heating market in Macedonia

According to the Energy Law in Macedonia, the production, distribution and supply of heating energy are regulated energy activities and the regulation of these activities is the responsibility of the Energy Regulatory Commission. Providers of regulated energy activities, located on the territory of Skopje since 2013 are:

- Balkan Energy Ltd (production, distribution and supply of heating energy),
- Skopje Sever AD Skopje (production, distribution and supply of heating energy) and
- ELEM Branch Energy (production, distribution and supply of heating energy).

The heating service is paid based on the measured delivered energy to the building. Regulation and measurement of delivered energy in a building is done from a central dispatching system. The cooling market and the price for cooling are not defined in Macedonia. For empirical studies, the price for cooling is formed on the basis of the price of electricity and heat.

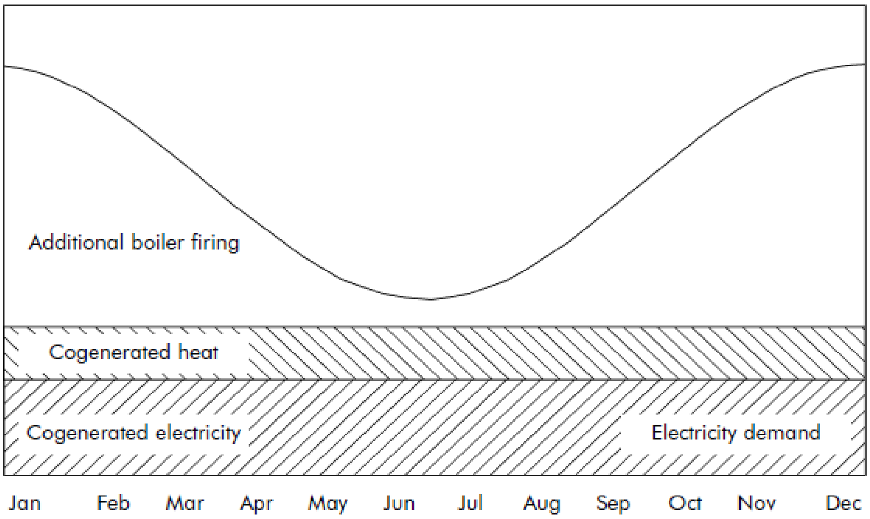
3 THE TRIGENERATION SYSTEM IN THE CASE OF ERA CITY

In this chapter an overview is given on the importance of proper sizing of the power plant. To properly calculate the demand for heating, cooling and electricity, the climate conditions in Macedonia and the demanded temperature regimes for thermal comfort in the ERA complex need to be analysed. In this chapter, I give a summary of the heat and cold consumption and the technical sizing of the chosen equipment is given.

3.1 Understanding the Need for Proper Sizing

A well-designed and operated cogeneration unit will always provide higher energy efficiency than separate heating and electricity generation. A single input fuel is used to generate heat and electricity, and the cost saving is dependent on the price differential between the cost of that fuel and the value of bought-in electricity that the cogeneration unit replaces. However, although the profitability of cogeneration generally derives from the electricity produced, its success depends on being able to put the heat into practical use. Therefore the prime criterion is the existence of a heat application that can viably be served by cogeneration. As a rule of thumb, cogeneration is likely to be viable where heat is in demand for at least 4500 hours per year. The best possible situation is one in which both heat and electricity can be fully used on the production site. In most instances, however, electricity production exceeds local demand when the cogeneration unit is deployed in line with the demand for heat. This is illustrated in Figures 8 and 9. Figure 8 shows the situation in which the cogeneration unit is sized according to the demand for electricity. The electricity demand is in this example constant over the year, leading to a constant level of heat supply. Since heat demand is much higher in the winter months, additional heat production is required.

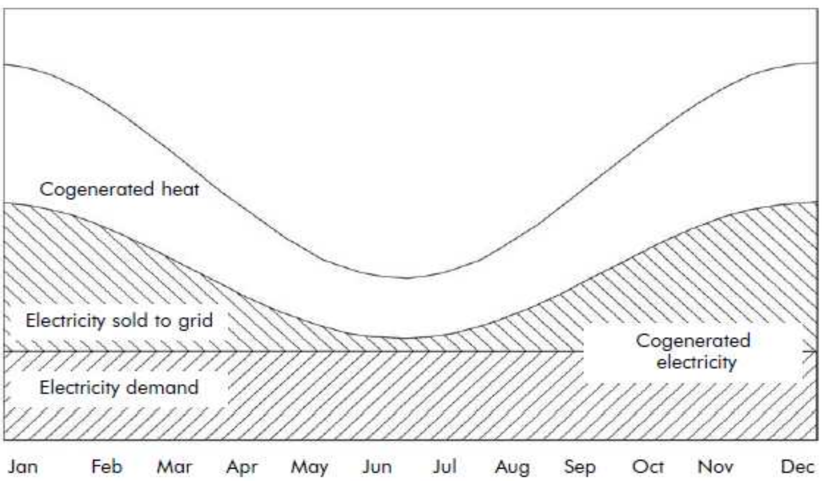
Figure 8: Cogeneration Unit Set Up to Follow Electricity Demand



Source: R. Smit, *Distributed generation and renewables*, 2006, p. 4, Figure 3.

Figure 9 shows the situation in which the cogeneration unit is sized according to the heat demand. Electricity availability follows heat production while electricity demand remains constant. If electricity supply exceeds demand the shortfall can be purchased from the grid while excess electricity can be sold to the grid.

Figure 9: Cogeneration Unit Set up to Follow Heat Demand



Source: R. Smit, *Distributed generation and renewables*, 2006, p. 5, Figure 4

In most applications of cogeneration, the demand for heat is higher than that for electricity (seen over the year). In other words, the heat to power ratio is higher than 1. However, this ratio can vary considerably during the year and even during the day. From an environmental perspective it is always best for a cogeneration unit to follow the heat demand, but from an economical perspective it is sometimes attractive to follow the electricity demand. When following the electricity demand there will be times (especially in the summer) when the heat produced cannot be used and has to be dissipated, with a negative effect on the overall efficiency of the cogeneration unit.

When a cogeneration unit is set up to follow heat demand there will be times (especially in the winter) when a lot of the electricity produced will have to be sold to the grid. If the market price of electricity is low at these times, this will have a negative effect on the overall economic performance of the unit.

3.2 Analysis of the Demand of the Project

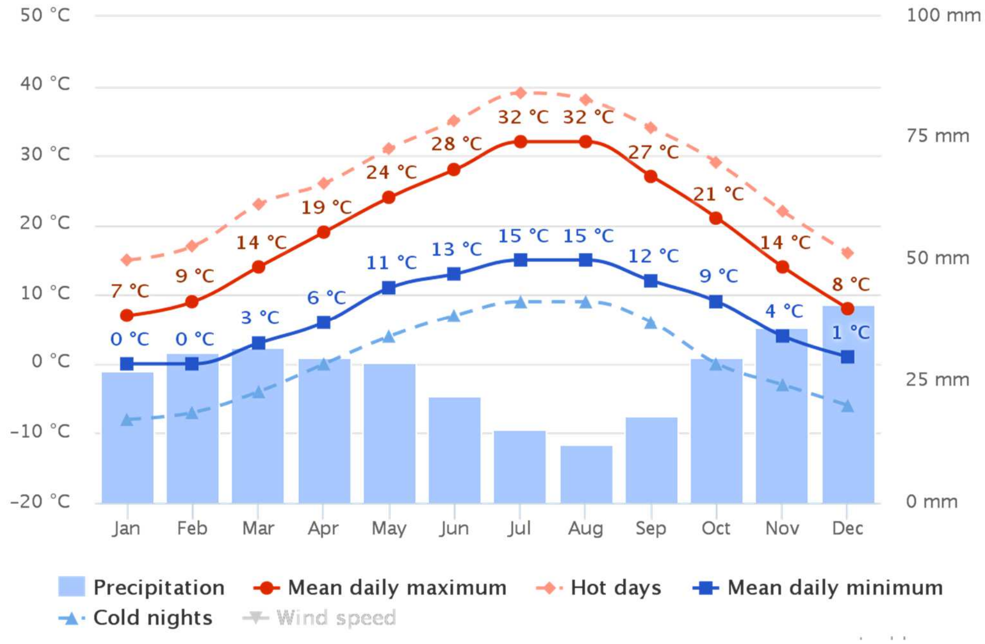
For a good understanding of the needs for thermal comfort in the ERA complex, the investor needs to analyse the climate in Macedonia. Having in mind the thermal comfort in the premises of the ERA complex, the demand for electricity, heating or cooling the complex can be calculated and used in the further analyses. The demand for electricity, heating and cooling will help determine the correct sizing of the trigeneration power plant that will satisfy the needs of the complex.

3.2.1 Climate in Macedonia

The climate conditions in Macedonia are illustrated in Figure 10. Skopje has a humid continental climate with warm summers and no dry season. Figure 10 describes the typical weather in Skopje over the course of an average year. It is based on historical records from 1977 to 2012 provided by the World Meteorological Organization (WMO). In Figure 10 the "mean daily maximum" (solid red line) shows the maximum temperature of an average day for every month, the "mean daily minimum" (solid blue line) shows the average minimum temperature on average for every month. The hot days and cold nights (dashed red and blue lines) show the average of the maximum average daily temperatures and minimum average daily temperatures of each month in the last 30 years. Over the course of a year, the temperature typically varies from -4°C to 32°C and is rarely below -11°C or above 36°C.

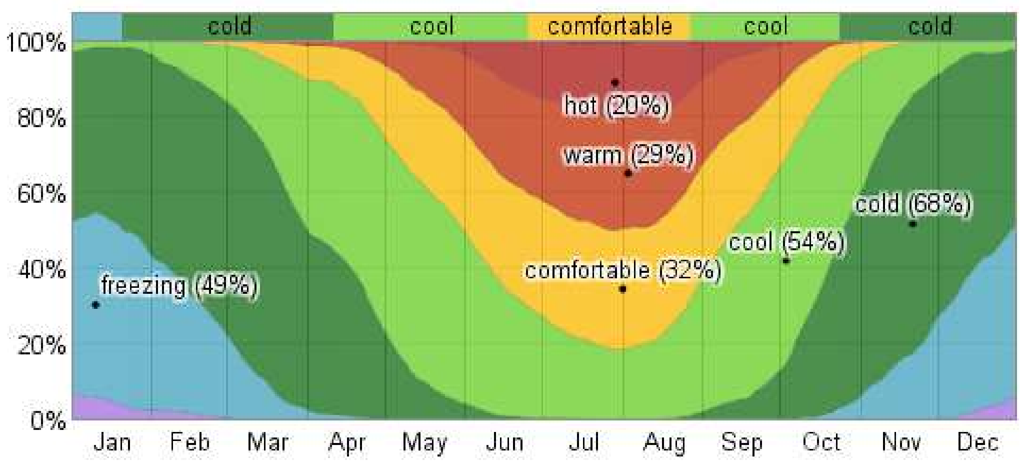
According to information on the website Weather Spark (Skopje-Ilinden-Macedonia, 2016), the warm season lasts from May 31 to September 18 with an average daily high temperature above 26°C. The hottest day of the year is July 30, with an average high of 31°C and low of 17°C. The cold season lasts from November 23 to February 23 with an average daily high temperature below 9°C. The coldest day of the year is January 10, with an average low of -4°C and high of 4°C.

Figure 10: Average Temperature per Month in Macedonia



Source: Meteo blue, Skopje, Macedonia, 2016

Figure 11: Fraction of Time Spent in Various Temperature Bands



Source: Weather spark, Skopje-Ilinden-Macedonia, 2016

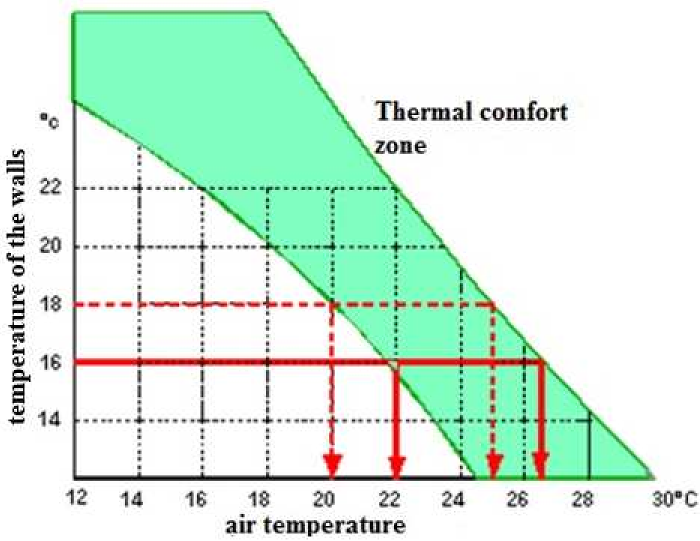
On Figure 11 the average fractions of time spent in various temperature bands are presented: frigid (below -9°C), freezing (-9°C to 0°C), cold (0°C to 10°C), cool (10°C to 18°C), comfortable (18°C to 24°C), warm (24°C to 29°C), hot (29°C to 38°C) and sweltering (above 38°C). Figure 11 also shows that approximately 1000 hours, the temperature of the ambient temperature is within the comfort band from 18° C to 24 ° C, and all other hours in potential fall in the requirement for heating or cooling. For ease of comparing the results of empirical studies the data is then compared with temperatures of places in Slovenia. Winter temperatures in Skopje are very similar to those in Ljubljana and the summer temperatures with those from Nova Gorica.

The start of the heating season in Macedonia is declared as the following day after three consecutive days in which the outside temperature at 21:00 hours was below 15° C. The end of the heating season is similarly defined, when the outside temperature at 21:00 hours is above 15° C for three consecutive days, and after that date there are no more than three consecutive days during the year in which the temperature drops to 15° C or less. The third day of the last such series represents the end of the heating season. The Cooling season is considered to start when the outside temperature exceeds 24° C.

3.2.2 ERA City's demand for heating, cooling and electricity

In winter the control of indoor air temperature is usually treated as a constant. In the study for ERA City, the indoor space heating programs operate on an hourly basis, and the day and night temperature are adjusted with a controller separately for every enclosed space heating unit. Changes of the set temperature are provided on basis of manual correction and there are no functional links with other relevant heating parameters. One of the important parameters is the temperature of the shell surfaces. Together with air temperature of the space, it is crucial in creating thermal comfort in the space heating unit. The relationship is shown in Figure 12.

Figure 12: Temperature for Thermal Comfort



Source: Bas, D. at all, *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 9, Figure 3

The investor's decision is to permanently maintain the ambient temperature, which will be maintained on the premises outside working hours, at a temperature of 15°C. This is also the lowest temperature of the peripheral areas of Figure 12 where the air temperature in the room falls in the comfort range temperature of 23°C. During working hours, in the winter regime, the investor wants to maintain the internal temperature of the premises at 23°C. This does not mean that the temperature in the individual rooms within the complex cannot be higher or lower, but that the calculated amount of energy can provide thermal comfort within the complex of buildings. The designed minimum for the outside temperature is set to -15°C.

Table 1: Desired Temperature Regimes Divided by Business Area

Days	Hours	Business area	Business mall – 80% trade	Business mall – 20% restaurants	Hotel
Mon-Fri	00-09	15	15	15	23
Mon-Fri	09-17	23	23	23	23
Mon-Fri	17-21	15	23	23	23
Mon-Fri	21-24	12	15	23	23
Sat, Sun	00-09	15	15	15	23
Sat, Sun	09-22	15	23	23	23
Sat, Sun	22-24	12	15	15	23

Source: Bas, D. at all, *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 10, Tables 3-5

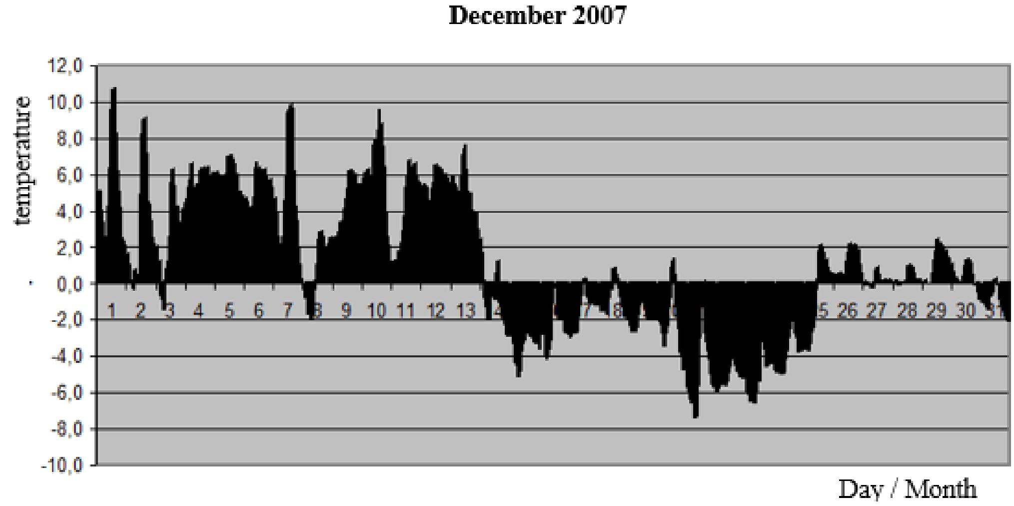
Achieving comfortable temperature in the premises during summer is much more complicated because temperature regulation depends not only on external temperature, but also to a large extent on the temperature gains, which are located in the premises (lighting, number of visitors and all electrical appliances, direct solar radiation, etc.). Given that this data for a particular object is not known, the temperature of the regulated premises for cooling is a function of the outdoor temperature or temperature excess. The temperature designed to offset the abovementioned unknown gains is set to 24°C regardless of the operating time. The regimes of operation of individual facilities are shown in the Table 1.

3.3 ERA City's Planned Demand for Heating, Cooling and Electricity

3.3.1 Planned heat demand for the project

Based on the information received for the climate in Macedonia and the hourly temperatures measured in 2007 and the requirement parameters from the investor regarding optimizing the temperature of the ERA city complex, the demand for heating and cooling can be calculated.

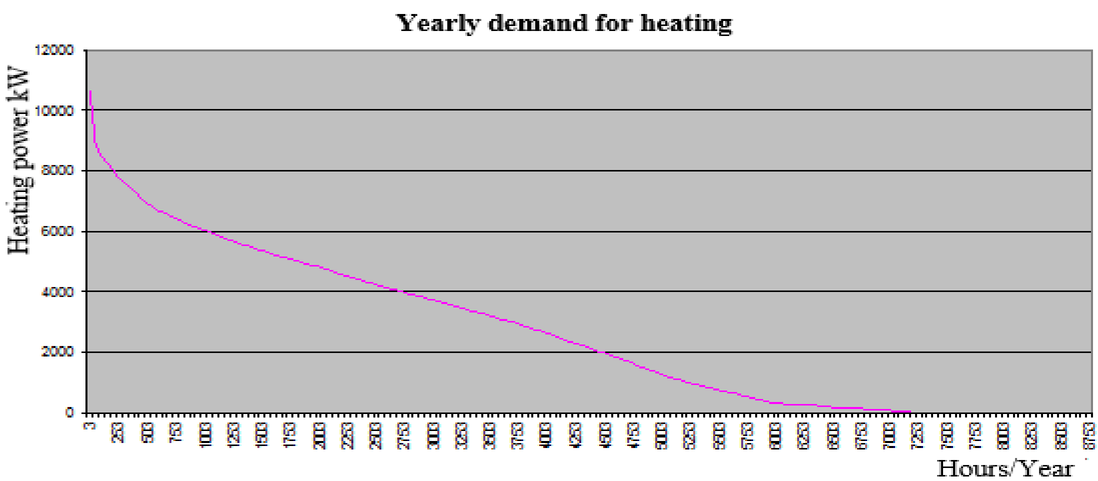
Figure 13: Daytime Temperatures in December 2007 - the Coldest Month of the Year



Source: Bas, D. at all, *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 19, Figure 3

In Figure 13, the heat consumption is the most important element for planning the size of the facilities for simultaneous production of heat and electricity. Proper sizing is the key to economy of operation and the related revenues and expenses of the power plant as a whole. Figure 13 shows that temperature variations during the coldest months are constantly moving outside thermal comfort temperature. Accordingly, the heat consumption for space heating is significant. As already mentioned, the annual heat consumption is calculated on the basis of temperature deficit simulation for each object in the complex. The simulation has been carried out on an hourly basis. The simulation result is a scaled diagram of the consumption of energy for heating, which follows in the Figure 14.

Figure 14: Yearly Consumption Demand of Heating Energy



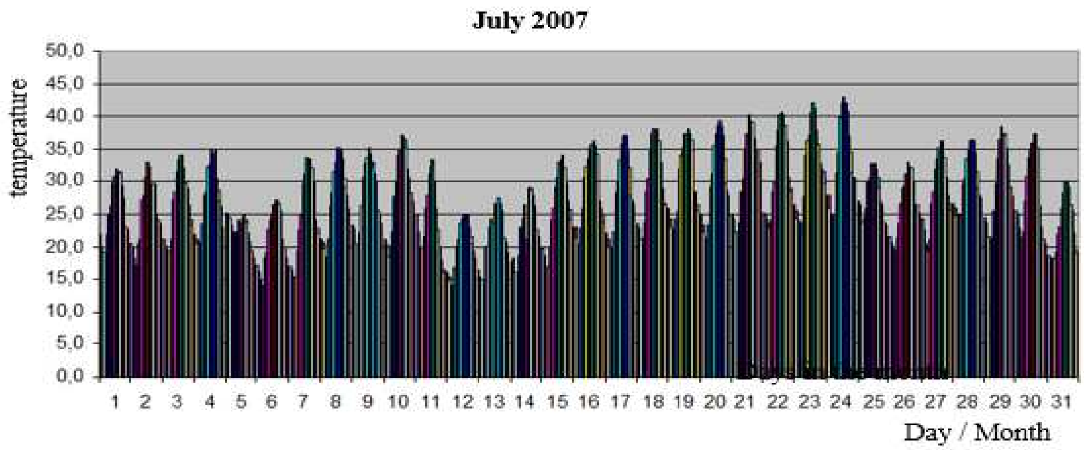
Source: Bas, D. at all, *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 20, Figure 4

In Figure 14, the consumption in the first part has a steep decline, but then it settles down and falls almost linearly with the increasing number of operating hours of the plant. In the received documentation there is no demand for heating domestic hot water, limiting the consumption of heat in the summer months, to the duration of the heating needs to approximately 5000 hours per year. For heating of the planned building complex, an annual consumption of 22,300 MWh of energy is planned.

3.3.2 Planned cooling demand for the project

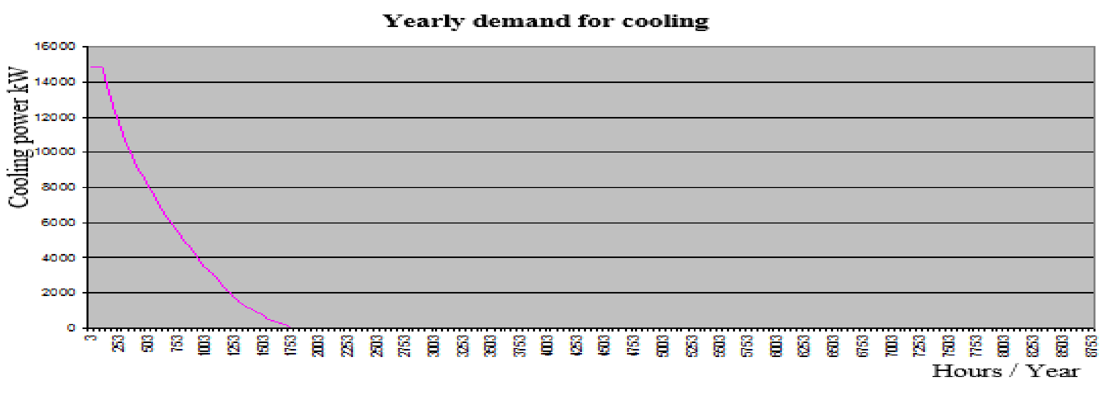
Just like heat consumption, cooling consumption is defined as an hourly variable on the basis of the hourly temperature excess for each facility in the complex. Figure 15 shows the temperature for the warmest month of the year 2007. From the diagram it can be seen that the temperature is moving out of the range of thermal comfort, so it is necessary to cool the facilities and the energy consumption is considerable.

Figure 15: Daytime Temperatures in July 2007 - the Warmest Month of the Year



Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 21, Figure 5

Figure 16: Yearly Consumption Demand of Cooling



Source: Bas, D. at all, *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 21, Figure 6

In Figure 16, the consumption of cooling has a steep decline with the number of operating hours of the plant. From Figure 16 it can be seen that the annual cooling energy consumption diagram shows that the required cooling capacity is equal to or even greater than the energy required for heating. This is because the energy consumption is lower due to fewer operating hours of the cooling systems. For cooling of the planned building complex, an annual consumption of 9,726 MWh of cooling is planned.

3.4 Technical Characteristics of the Project

The investor has decided that the entire complex ERA CITY SKOPJE is to be provided with all energy carriers from one place, an energy facility within the hotel complex which is to produce and service the entire complex with heat, cool and needed electricity. Energy facilities are to be built simultaneously with the first facility in the complex and by phases are to cover all the needs for heating and cooling facilities. The produced electricity could be spent in the complex or it can be drained into the distribution electrical network. Input fuel for the operation of both gas boilers and cogeneration engines will be natural gas.

The trigeneration system is selected as technology for simultaneous production of energy carriers, which will cover the need for production of heating and hot water, electricity to drive the technical equipment of the buildings and surroundings, lighting, air conditioning and ventilation, and through absorption chillers production of cool needed for cooling of the facilities. The trigeneration system consists of three CHP units for combined heat and power (hereinafter: CHP) and absorption cooling units for the production of cooled water for cooling. For the purpose of satisfying the peak of thermal energy demand as an operating reserve in heat energy production, a hot water boiler with a conventional gas burner will be installed.

The management of operation of individual devices is regulated so that the priority dispatch of heat – thermal, is from the cogeneration plants with combined heat and power. In the case of a deficit of heat (in winter peak), the additional gas boiler will produce the missing peak amount of heat. In the summer or during cooling, the heat generated in the operation of cogeneration facilities is used for the operation of the absorption chillers to produce cool. The size of the absorption chillers is sized to the produced thermal energy from cogeneration plants. The missing cooling energy is provided by the compression chillers which, similar to the gas boiler for thermal, provide the operating reserve production capacity for cooling energy. The distribution pipes for hot and cold water to individual buildings are made with pre-insulated pipes according to the implementing projects to build infrastructure ZUAS Skopje. In 2007 a study has been developed by the company ZUAS from Skopje for the hot-water supply system of all the buildings, and a building permit was also obtained. Distribution pipes for cooling are included in the scope of the aforementioned study for hot-water distribution pipes. They are planed together with the construction of infrastructure for the entire complex. The primary energy source is natural gas. Its energy value is 33,000 kJ / Nm ^{3} or 9.250 kW h / Nm ^{3}. In order to satisfy the needs for consumption of power, heat and cooling energy through every facility, the proper equipment is to be selected carefully. The planned trigeneration plant should include the parameters shown in Table 2.

Table 2: Planned Trigeneration Plant Power

Electricity:	**Power**
3 cogeneration plants, each of 2 MW electrical power	6.0 MW
Heating:	
3 cogeneration plants, each of 1.8 MW thermal power	5.4 MW
2 gas boilers each 5 MW thermal power	10.0 MW
1 gas boiler power 3 MW thermal power	3.0 MW
Total installed:	**18.4 MW**
Cooling:	
3 absorption chillers each of 1.25 MW cooling power	3.75 MW
2 compressor cooling systems of power 4 MW each	8.00 MW
3 compressor cooling power plants of 2 MW each	6.00 MW
Total installed:	**17.75 MW**

Table 3: CHP Module Description

Description CHP MODULE **Manufacturer GE Jenbacher Austria, type GE J612**	**Unit**	**J612**
Nominal electric power	kW	2002
Electrical efficiency		44,7
Rated Voltage	kV	10,5
Rated output	kW	1774
Thermal efficiency	%	39,6
Total power	kW	3777
Total recovery	%	84,4
Gas consumption	sm3 / h	471
Oil consumption	L/ OPH	1,53
Energy intake	kW	4477
Recommended min load		0,5
Electric power peripherals	kW	30
Average cost of service	€ / OPH	9,9

Each cogeneration unit produces 2.0 MW of electricity, so the total installed 6.0 MW power is to generate electricity. All the equipment needs to be installed in stages in the trigeneration plant with all necessary associated equipment. Distribution pipes for hot water and cold water will be led from the trigeneration plant to the business complex. To carry out the simulation calculations, the CHP module shown in Table 3 is chosen.

The summary of the estimated yearly supply and demand of the electricity, heating and cooling energy is calculated on the basis of the analysis. Table 4 below also gives a summary of the consumption of natural gas and electricity used for the generation of power and for the internal use and the working hours of the units. The parameters in Table 4 are to be used as a basis for all calculations later. All details per month are shown in Appendix A.

Table 4: Summary of the Estimated Yearly Supply and Demand Quantities

Quantities Supply / Demand	**Unit of measure**	**Year**
Sale of electricity	kWh	30,635,603
Sale of heat	kWh	22,297,532
Sale of cool	kWh	9,726,222
Consumption of Nat. gas	Nm3	7,240,984
Consumption of electricity	kWh	1,637,535
Working hours CHP 1	Hour	6,815
Working hours CHP 2	Hour	5,066
Working hours CHP 3	Hour	4,916

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 26, Table 4

4 FINANCIAL ANALYSIS OF ERA CITY

Since 2007 when the project went live and was promoted by the investor, certain things occurred. The initial investor ERA city filed for bankruptcy and the project was closed. This however does not reflect on the relevance of this topic. Only this month, September 2016, there is an open call for three feasibility studies for building three cogeneration plants in Macedonia. As stated before, Macedonia needs to comply with the Energy commission's Directive 2009/73/EC to stay on the road for EU integration, and the effects of using the CHP plants instead of the existing solid fossil fuelled plants from an ecological perspective are huge. That is why my fifth chapter is based on the price analysis and the projections of the costs and revenues of a trigeneration power plant for a new investor. The analysis will be based on the income statement and the cash flow statement. The projections of the free cash flows assist in calculating the key indicators of capital budgeting, such as NPV, IRR, the PI and the payback period. The sensitivity analysis helps with understanding the break-even point and the risks if the price of the natural gas and the price of the electricity sold on the market change.

4.1 Analysis of Input and Output Prices in Macedonia

The economic analysis price provided by Energy Regulatory commission (hereinafter: ERC) on June 29 2016 is used for the calculation. The output price of electricity and the input price of natural gas are taken as average prices for the last year on the free unregulated market. All prices include VAT and all additional costs. Prices are calculated in EUR with exchange rate on the same day taken from the website of the National bank of Republic of Macedonia (Kursna lista, 2016) which was 61.695 MKD for 1 EUR. The exchange rate on June 29, 2016 for the USD is 55.7166 MKD.

4.1.1 Purchase prices of natural gas in Macedonia

Until December 2014, the ERC was responsible for regulating the selling price of natural gas in Macedonia. Since then, the gas market is not regulated and the price of gas is according to the market. For 2016, the average import price of natural gas is 180 USD/1000 normal cubic meter (hereinafter: Nm^3 - Temperature: 0°C, Pressure: 1.01325 bar). The final price of natural gas is calculated from the import price of natural gas, the exchange rate differences and all the dependent costs, meaning the price of the supply chain, the cost of the transmission and management systems for the transmission of the natural gas and the VAT. The final price of natural gas that is to be used in the calculations with VAT is 15.57 MKD/ Nm3 or 0.2525EUR/Nm^3. The price was provided by Prom gas in September 2016.

4.1.2 Purchase prices of electricity in Macedonia

ERC is responsible for regulating the selling price of electricity in Macedonia. They approved the latest electricity prices on 01/07/2015. The final retail price for business consumers is 10.4 MKD/kWh or 0.1686 EUR/kWh (price includes VAT and all other costs).

4.1.3 Sales price of electricity in Macedonia

The selling price of the electricity generated from cogeneration in Macedonia is not regulated. All producers can sell their energy freely on the market. That is the reason why the average prices between the base and peak price on the electricity market for the last 12 months are used as bases for calculation of the final price. The relevant market for Macedonia is the Hungarian power exchange. The calculated selling price is 42.042EUR/MWh. The data for the average price was taken from the Hungarian power exchange market (August 2016) and is shown in Table 5.

In 2007, when the old project was still active, the Government of Macedonia, agreed to buy the electricity generated by cogeneration at a subsidized price. The investor also had a valid permit to operate on the market and sell the electricity. The subsidized price was 65 EUR/MWh and was comparable to the current market price, putting the investor in a more favourable position.

Table 5: Selling Price of Electricity in Macedonia, EUR

	Jul	Aug	Sep	Oct	Nov	Dec	Jan
Peak price	47.3	54.5	51.5	48.6	50.2	51.18	31.9
Base Price	42.4	47.6	44.1	41.5	42.3	43.1	26.4

	Feb	Mar	Apr	May	Jun	Jul	Aug
Peak price	29.1	30.8	29.2	37.5	39.3	37.26	44.85
Base Price	25.8	29.2	27.2	32.8	35.2	33.23	39.23

Source: Hungarian power exchange, Market data, 2016

4.1.4 Sales prices for heating in Macedonia

The heating prices in Macedonia are regulated. The latest price which includes the adjusted average cost of production, distribution and supply of heating energy was adjusted in 2015. As ERA city represents a huge complex business area, the prices relevant for the calculations in this thesis are taken as prices for Office space. The prices are taken from the ERC web site, from the decision for the distributor for heating energy JSC Macedonian Power Plants Skopje - Skopje Branch Energy as selling price to all their consumers connected to the distribution network. In the calculations the same price of 3,876.75 MKD/kWh or 0.0628 EUR/kWh is to be used (ERC of R. Macedonia, TE-C-2015 07 31 – Decision for prices for district heating, 2016). For the thermal power the fixed amount is a fix amount of cost that the consumers pay for the used power. In the calculations thermal power of 1,001,573.12 MKD/MW or 16,234.27EUR/MW is to be used.

4.1.5 Sales prices for cooling in Macedonia

The price for cooling in Macedonian is not regulated. It is usually calculated based on the coefficient for transforming electricity from heating energy into cooling energy. In the calculations the price of 4,303.19 MKD/kWh or 0.0697 EUR/kWh is to be used. For cooling power the fix amount of 1,111,746.16 MKD/MW or 18,020.04 EUR/MW is to be used. Actual pricing mechanisms of different energy are not taken into account for the collection of data on prices of energy, so in practice there may be deviations from energy prices.

4.2 Assessment of Investment Expenditures

Economic calculation is made on the basis of quantity of electricity, heat and cooling energy required for heating and cooling of the planned buildings in the complex. The aforementioned prices of different energy sources and energy, which vary with time according to the state's energy policy, have also been taken into account.

According to Commission Delegated Regulation (EU) Article 17 (Discounting of cash flows) No 480/2014, the European Commission recommends for the programming period 2014-2020 a 4 % discount rate in real terms, which is considered as the reference parameter for the real opportunity cost of capital in the long term. Values differing from the 4 % benchmark may be justified on the grounds of international macroeconomic trends and conjunctures, the Member State's specific macroeconomic conditions and the nature of the investor and/or the sector concerned. As Macedonia is still not part of the EU, and having in mind the political instability in the country in the last few years, the new investor in the project in Macedonia needs a required return on equity bigger than 4%. The adjustment is made on the base that the interest rates in Macedonia are calculated on the basis Euribor + 3%. Using the same logic, the required return on debt r_d on the project in Macedonia is equal to the required rate of return in EU of 4% + 3%, or in total 7%. The income tax in Macedonia is 10%. The *WACC* of the project in Macedonia (hereinafter: WACC_{M}) can be calculated by using Equation 14. In Equation 14, the values where w_d is 100%, w_{ps} and w_{ce} are 0%, r_d is 7%, r_{ps} is 3% and T is 10% can be substituted. Equation 15 shows the calculation of $WACC_M$.

$$WACC_M = 100\% * 7\ \% + 0 * 3\ \% = 7\% \tag{15}$$

The required return on debt r_d on the project in Slovenia is equal to the required rate of return in EU of 4%. The WACC of the project in Slovenia (hereinafter: WACC_{S}) can be calculated using the same principle by substituting the values in Equation 14.

$$WACC_S = 100\% * 4\ \% = 4\% \tag{16}$$

The WACC_{S} calculated in Equation 16 is equal to the required rate of return in EU of 4%. The basic assumptions taken into consideration in the financial appraisal of the trigeneration power plant are:

- The lifespan of the project is 20 years.
- The input prices do not change in the period of analysis. All projections are made in constant prices from June 2016.
- The demand for electricity, heating and cooling energy will remain the same thought the years,

- At the end of the life span of the project plus the residual value of the project in the amount of depreciated value of fixed assets, is EUR 1,286,448. This is than taken as a salvage value in the calculations.
- When calculating the economic analysis of the project, the sunk costs were considered and are not part of the incremental cash flows.

The estimated value of the investment is based on the previous analysis and conclusions and represents the sum of the investment in the land, the CHP equipment, the construction and assembly work, the operational expenditures like the costs for landscaping and the financial expenditures like the costs for easement and compensation for damages, and costs for other unforeseen costs and works. Table 6 shows the estimated values for the investment in this project.

The price of the land property in Table 6 is zero, because it is owned by the investor for many years and at this stage does not constitute an investment cost. The model for the plant is built on the basis of the requirements from the analysis of the collected data and a detailed simulation of the operation of the energy facility for the reference year on an hourly basis. It takes into account all influences during the operation of the energy facility. The model also recognizes the hourly needs of the system for heating or cooling, and the applicable load on the production. Due to the extensive analysis, the tables below only provide synthetic results of the analyses.

Table 6: Estimated Total Value of the Investment, in EUR

INVESTMENT VALUE	**Standard prices (in EUR)**	**%**
Land	0	0.00%
Construction work (Building)	520,000	4.91%
Cogeneration boiler	3,640,000	34.34%
Mechanical and electrical equipment including assembly parts	5,408,000	51.02%
TOTAL INSTALLATIONS	**9,568,000**	**90.34%**
Landscaping	0	0.00%
Cost of easements and compensation	0	0.00%
Other costs of the investor	449,200	4.37%
Unforeseen work	574,080	5.42%
Total investments	**10,591,280**	**100.00%**
Financing costs	0	0.00%
Total investments costs	**10,591,280**	**100.00%**

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 25, Table 4

In Table 8 the first part represents the collected data of the summarized monthly quantities of different energy carriers that will be used in the operation of the facility or are a product of the operation of the facility. Thus, they are relevant to the financial analysis. In the first part, Quantities for Supply/Demand, the yearly quantities of electricity produced by the cogeneration and sold by the distributor are presented, deducted for the own consumption of electricity production, which is bound to only produce electricity and the amount representing the net amount of the threshold electricity. Natural gas is provided as an only energy source. The quantities take into consideration all consumption of natural gas, to cover the heat generation in the cogeneration, as well as for the production in peak energy with gas boilers. The quantities of gas have also incorporated natural gas consumed to cover regular network losses as well as losses of the boiler room. The model accounts for the positive difference in price between buying and selling electricity. This allows the investor to have all produced electricity sold to the grid at a higher price than the purchasing electricity used to satisfy the energy needs of the facility. The last part is the summary of the time of operation or the working hours of the CHP plant. This information is very important in two aspects. The first aspect is the control of the maintenance and service costs and the second is the utilization of the CHP module.

In the second part Sales revenues are shown the amounts of the revenues generated by the plant, where the amounts of the estimated revenues are calculated as a multiplication of the quantities of produced electrical, heating and cooling energy by the sales and purchase prices, shown in Table 7. The relevant prices are defined previously in the text:

- the sales price for electricity is explained in chapter 4.1.3 on page 47;
- the sales price for heating energy is explained in chapter 4.1.4 on page 48;
- the sales price of cooling is explained in chapter 4.1.5 on page 48.
- the purchase price of the input natural gas is explained in chapter 4.1.1 on page 46;
- the purchase price of electricity is explained in chapter 4.1.2 on page 47.

Table 7: Summary of Sales and Purchase Prices for ERA City in Macedonia, in EUR

	Unit of measure	**Price EUR**
Sales price for electricity	kWh	0.0420
Sales price for heating	kWh	0.0628
Sales price for cooling	kWh	0.0697
Purchase price for gas	Nm^3	0.2525
Purchase price for electricity	kWh	0.1686

In the third part of the Table 8, called Production costs, the operating cost are calculated. The production costs include the cost for maintenance of the CHP. These costs are calculated based on the number of working hours of the CHP. The monthly quantity and value of production are presented in Appendix A.

Table 8: Yearly Projections of Revenues and Production Costs in Macedonia

Quantities Supply / Demand	Unit of measure	Yearly Amount
Sale of electricity	kWh	30,635,603
Sale of heating	kWh	22,297,532
Sale of cooling	kWh	9,726,222
Consumption of Nat. gas	Sm3	7,240,984
Consumption of electricity	kWh	1,637,535
Working hours CHP 1	Hour	6,815
Working hours CHP 2	Hour	5,066
Working hours CHP 3	Hour	4,916
Sales revenue		
Sale of electricity	€	1,109,977
Sale of heating	€	1,401,118
Heating fix part	€	194,811
Sale of cooling	€	331,294
Cooling fix part	€	216,240
Production costs		
Natural gas	€	1,796,397
Electricity	€	46,184
Service costs CHP1	*14€/h*	94,629.00
Service costs CHP2	*14€/h*	70,344.00
Service costs CHP3	*14€/h*	68,261.00
Difference		**1,177,625**

4.3Assessment of Operating Expenditures

The economic calculation takes into account the following expenditures: the cost of materials, cost of services, depreciation, labour costs and administrative costs. All of them are explained in detail below. The assumptions are made by relevant professionals and are taken from the project documentation for the project ERA City.

4.3.1 Costs of materials

The other material expenditures include the costs of maintenance, materials, office supplies and similar material costs, estimated at 0.2% of the value of the construction work, and 0.5% of the value of the equipment. The cost of materials is presented in Table 9 and are calculated based on the estimated cost shown in Table 6.

Table 9: Costs of Materials, in EUR

Type of cost	Base for calculation	Percentage of the annual cost	The annual cost of materials
From the works	520,000	0.20%	1,040
From the value of the equipment	9,048,000	0.50%	45,240
TOTAL			46,280

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 25, Figure 4

4.3.2 Costs of services

The expenditures for services, which include the maintenance costs and the costs of insurance, are shown in Table 10. They are calculated based on the cost shown in Table 6.

Table 10: Costs of Services, in EUR

Type of cost	Basis for calculation	The percentage of the annual cost of basics	The annual cost of services
Cost of services including:			90,063.52
Maintenance costs			47,698.40
The value of other costs of the investor	449,200	0.20%	898.40
From the works	520,000	0.30%	1,560.00
The value of the equipment	9,048,000	0.50%	45,240.00
Cost of insurance			42,365.12
The total value of investments in fixed assets	10,591,280	0.40%	42,365.12

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 25, Table 4

Maintenance expenditures include the cost of maintenance of the CHP facility and are estimated as 0.5% of the value of the equipment, cost of the work, estimated at 0.3% of the value of construction work, and other costs estimated at 0.5% from the value of the other investment's costs. The cost of insurance or the insurance premium costs are estimated at 0.4% of the total investment in fixed assets and presented in Table 10.

4.3.3 Depreciation

Depreciation is determined by the specific types of equipment investment. According to IAS 16.7, extracted on the website Iasplus, (IAS 16 — Property, Plant and Equipment, 2016) all items of property, plant, and equipment should be recognised as assets when it is probable that the future economic benefits associated with the asset will flow to the entity, and the cost of the asset can be measured reliably. This recognition principle is applied to all property, plant, and equipment costs at the time they are incurred. These costs include costs incurred initially to acquire or construct an item, plant and equipment and the costs incurred subsequently to add to, replace part of, or service it. If in continued operation the plant or any equipment require regular major inspections for faults regardless of whether parts of the item are replaced, the cost is recognized in the carrying amount of the item of property, plant, and equipment as a replacement if the recognition criteria are satisfied.

Table 11: Depreciation Rates

Type of assets	Depreciation %
Land	0,0
Construction work	3,0
Cogeneration	6,7
Mechanical and electrical equipment including assembly parts	4,0
Landscaping	3,0
Other costs of the investor	10,0
Unforeseen work	10,0

Table 12: Amortization and Depreciation Plan, in EUR

Year	Construction work	CHP	Elect. Equip/ services	Other costs	Unforeseen work	Annual depreciation costs	Residual value
2016	15,758	242,667	216,320	44,920	57,408	577,072	10,014,208
2017	15,758	242,667	216,320	44,920	57,408	577,072	9,437,136
2018	15,758	242,667	216,320	44,920	57,408	577,072	8,860,063
2019	15,758	242,667	216,320	44,920	57,408	577,072	8,282,991
2020	15,758	242,667	216,320	44,920	57,408	577,072	7,705,919
2021	15,758	242,667	216,320	44,920	57,408	577,072	7,128,847
2022	15,758	242,667	216,320	44,920	57,408	577,072	6,551,774
2023	15,758	242,667	216,320	44,920	57,408	577,072	5,974,702
2024	15,758	242,667	216,320	44,920	57,408	577,072	5,397,630
2025	15,758	242,667	216,320	44,920	57,408	577,072	4,820,558
2026	15,758	242,667	216,320	0	0	474,744	4,345,813
2027	15,758	242,667	216,320	0	0	474,744	3,871,069
2028	15,758	242,667	216,320	0	0	474,744	3,396,325
2029	15,758	242,667	216,320	0	0	474,744	2,921,581
2030	15,758	242,667	216,320	0	0	474,744	2,446,836
2031	15,758	0	216,320	0	0	232,078	2,214,759
2032	15,758	0	216,320	0	0	232,078	1,982,681
2033	15,758	0	216,320	0	0	232,078	1,750,604
2034	15,758	0	216,320	0	0	232,078	1,518,526
2035	15,758	0	216,320	0	0	232,078	1,286,448

In the calculations of the depreciation, the straight-line method of depreciation is used, meaning the assets will be depreciated proportionally to the depreciation rates every year. The depreciation rates per the different specific groups are shown in the Table 11. The estimated amortization and depreciation costs over the years are shown in Table 12 and are calculated based on the costs shown in Tables 6. I calculated the depreciation cost from 2016 to 2035.

4.3.4 Labour costs

The labour expenditures include the cost of wages, cost of supplementary pension, insurance contributions and taxes on the wages and other labour costs. The wages are planned for three people working full-time. According to the Statistical office of Macedonia and Slovenia, the average gross salaries in the respective countries in August 2016 (Average salary in Slovenia, 2016) are 532 EUR (Average salary in Macedonia, 2016) vs. 1571 EUR (Average salary in Slovenia, 2016). The value of labour costs in Macedonia is almost 1/3 of the labour costs compared to the average wage in Slovenia. The model adjusts for this in the calculations. The labour costs are presented in Table 13.

Table 13: Labour Costs in Macedonia, in EUR

Type of annual cost	ERA energetika (EUR)
Number of employees	3
Wages and salaries	16,613
Cost of insurance	823
Health and social contributions	3,696
Other labour costs	2,967
TOTAL	24,099

4.3.5 Administrative costs

The administrative expenditures are estimated at 0.5% of the investment and are represented by other operating expenses or overhead costs, which will cover the costs of management and administration costs, etc. The administrative costs are presented in Table 14 and are calculated based on the estimated costs shown on Table 6.

Table 14: Other Operating Costs in Macedonia, in EUR

Type of cost	Basis for calculation	The percentage of the annual cost of basics	The annual cost of services (EUR)
Other operating costs	10,591,280	0.50%	52.956

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 25, Table 4

4.4 Sources of Financing for the Project in Macedonia

The optimal capital structure of the company is a combination of equity and debt, which maximizes the value of the company (Brigham & Ehrhardt, 2005, p, 575). The project can be financed from internal and external sources. Internal sources of funding are undistributed profit from previous years and depreciation. External sources of funding can be divided into capital injections, credits or loans, subsides and specific forms of financing (leasing and factoring).

The new initial investor has to create a new company and that is why only the external sources of funding are relevant for him. I will analyse the situation when the source of capital is the injection of capital owners or capital investment, bank loans and subsidies. In economic theory there is no general consensus on the optimal capital structure of the company. In determining the optimal financial structure of the company attention should be paid to the relationship between capital structure and debt.

The newly established company is to be set up by the owner with a capital injection of 10,591,280 EUR. The initial capital of the company will be € 10,591,280. This ensures the capital adequacy of the newly established company for any further financing needs, which could be provided by other external sources. The distribution of capital is the purchase of tangible fixed assets in 2016 amounting to 10,591,280 EUR as shown in Table 6 on page 50.

The owner provides enough sustainable resources, and bank loans are not necessary. When the investment project will be realized, the possibilities for current subsidies provided by the Central Financing and Contracting Department (hereinafter: CFCD) and the National Fund (hereinafter: NF) of the Ministry of Economy in Macedonia should be investigated. They manage the Pre-Accession Assistance funds of the EU. In this phase of the project we cannot yet be sure which co-financing could be obtained, so they are not included in the calculation of the project. The open calls are limited in time and the possibility of financing must be checked before the realization of the project.

4.5 Appraisal of Financial Statements in Macedonia

4.5.1 Revenues and cost projections in Macedonia

Based on all information regarding the expenditures of the project, planned supply and the input prices, the Summarized Revenue and cost projections model of the project in Macedonia from 2016 till 2035 is shown on Table 15. The detailed revenue and cost model for Macedonia is shown in Appendix B.

Table 15: Summarized Revenues and Costs of the Project in Macedonia (000 EUR)

	2016	2017	2018-2025	2026	2017-2030	2031	2032-2034	2035
REVENUES	3253	3253	...	3253	...	3253	...	3253
Revenues from energy	3253	3253	...	3253	...	3253	...	3253
COGS	2866	2866	...	2764	...	2521	...	2521
Cost of materials	2122	2122	...	2122	...	2122	...	2122
Cost of gas and elect.	2076	2076	...	2076	...	2076	...	2076
Other material costs	46	46	...	46	...	46	...	46
Cost of services	744	744	...	642	...	399	...	399
Maintenance costs	48	48	...	48	...	48	...	48
Cost of insurance	42	42	...	42	...	42	...	42
Depreciation	577	577	...	475	...	232	...	232
Labour costs	24	24	...	24	...	24	...	24
Administrative costs	53	53	...	53	...	53	...	53
GROSS PROFIT	387	387	...	489	...	732	...	732
Financial income	0	0		0		0		0
Financial expenses	0	0		0		0		0
TOTAL PROFIT	387	387	...	489	...	732	...	732

The revenue and costs projections show that the yearly operations are positive, which means that revenues from operations generate a profit of 387 thousands EUR yearly in the first 10 years and 489 thousand EUR yearly for the next 5 and 732 thousands EUR in the last 5 years. The additional operating costs that occur for maintenance, servicing, insurance, labour and depreciation add up to 744 thousands EUR which are decreased after the 10th year to 642 thousands EUR and in the 15th year to 399 thousands EUR. In the further analysis we will check if this is sufficient for acceptance of the project and if the PV of the generated profit is sufficient to cover the initial investment costs.

4.5.2 Cash flow statement in Macedonia

As stated before in the Capital budgeting section, the Cash flow statement gives an overview of all the positive and negative cash flows of the project throughout the years. In the project, the purchase price of the asset or the initial investment is shown in year zero. The net cash flow in the last year of operation is very high, because it takes into account the cash flow from the residual value of the investment. The summarized cash flow statement for the project in Macedonia is presented in Table 16. The detailed cash flow statement is presented in Appendix C.

If we summarize all cash flows from 2015-2035, then the cash generated from the project is positive at 9980 thousands EUR. But if we include the time value of money, the yearly net cash flows are used to calculate the PV of the Cash flows. The sum of all PV positive cash flows from 2016 to 2035 is equal to 10547 thousands EUR. The PV of the positive cash flows is less than the initial 10591 negative cash flow, which makes the total cash flow negative.

Table 16: Summarized Cash Flow Statement, (000 EUR)

YEAR	**2015**	**2016**	**2017-2025**	**2026**	**2027**	**2028-2034**	**2035**
Cash at beginning of year	-10591	-10591		-949	15		7729
Investments	-10591	0		0	0		
Cash flow linked to operating costs	0	964	...	964	964	...	2251
Inflows	0	3253	...	3253	3253	...	4540
Revenues	0	3253	...	3253	3253	...	3253
Residual value	0	0	...	0	0	...	1286
Outflows	0	2289	...	2289	2289	...	2289
Cost of gas and electricity	0	2076	...	2076	2076	...	2076
Other material costs	0	46	...	46	46	...	46
Cost of maintenance	0	48	...	48	48	...	48
Cost of insurance	0	42	...	42	42	...	42
Labour costs	0	24	...	24	24	...	24
Administrative costs	0	53	...	53	53	...	53
Tax on profit	0	0		0	0		0
Financing activities	0	0		0	0		0
Net Cash flow	-10591	964		964	964		2251

4.6 Calculation of the Financial Analysis of the Investment in Macedonia

The calculated required return on equity of the project is equal to 7%. The relevant indicators for Capital budgeting assessment shown in Table 17 are also calculated.

The Static and the Dynamic capital budgeting indicators are calculated in Table 17. The static methods can be easily understood and in practice are easy to use (Cuts, 2004, p. 103). Two static methods, namely the ARR and the PP are calculated.

The Accounting rate of return or ARR is calculated based on the net cash flows shown in Table 16 on page 57 for the period of 20 years. The ARR is calculated in Excel by substituting the value for the amount received and amounts invested in the equation (5). Accounting rate of return is 9.71%. The ARR shows that it meets the criteria and is bigger than the discount rate.

Table 17: Static and Dynamic Capital Budgeting Indicators

Dynamic ratios	Value	Decision criteria	Decision
WACC	7 %		
Reinvestment rate	7 %		
NPV (EUR)	-43,815.17	Positive	No
IRR (in %)	6.95%	Bigger than *WACC*	No
MIRR (in %)	6.98%	Bigger than *WACC*	No
Payback period	11.98	Less than 15 years	Yes
Profitability index	0.996	Bigger than 1	No
Profitability index -1	-0.004	Bigger than 0	No
AAR	9.71%	Bigger than *WACC*	Yes

Where WACC is the Weighted Average Cost of Capital, NPV is the Net Present Value, IRR is the Internal Rate of return, MIRR is the Modified rate of return and ARR is the Accounting rate of return.

The payback period gives us a simple answer, by what time the invested funds will be recovered, but it also ignores the time value of money. The payback period is calculated on the basis of the cash flows data in Table 16, using equation (6) on page 13. The Payback period is 11.98 years, which fulfils the criterion to be less than 15 years.

These results show that the Static indicators are giving us positive results. However, before deciding on the project, the dynamic indicators have to be calculated and the time value of money has to be taken into consideration. The following dynamic indicators are calculated: the NPV, IRR, MIRR and the PI. The NPV method is based on discounted cash flows. In the case of newly established companies, the discount factor is determined on the basis of the previously calculated WACC of the company in Equation 15, which is 7%. The cash flows for a period of twenty years are used, shown in Table 16 on page 57 to calculate the Net present using equation (7) from page 14. The calculated NPV is -43,815.17 EUR. To accept the project, the NPV should be always positive. In our case the NPV tells us that the project will not generate cash, but will lose cash for the investors.

The IRR is calculated based on the cash flows shown in Table 16 on page 57, using equation (9) from page 15. The calculated IRR is 6.95%. For a positive decision, the expected value was supposed to be bigger than the WACC. The higher the IRR, the investment is more successful. In our case, the value of the IRR tells us that we would be losing money if we invest in this project.

The MIRR assumes that the reinvestment rate is equal to the IRR, which is usually not true. With the MIRR, the reinvestment rate can be specified separately. For our new company the reinvestment rate is taken to be equal to the WACC. With the cash flows from Table 16, and equation (12) the MIRR can be calculated. The calculation shows that the MIRR 6.98%. The MIRR is less than the cost of capital WACC, which means that the project is not acceptable.

The PI is calculated based on the cash flows from Table 16, and equation (13) on page 17. The project is acceptable if the PI is greater than one. The higher the index yield, the higher the rank of the project. In our case the PI is 0.996 which is less than one. By calculating the PI-1, in our case, for every 1 euro invested in the project, we would lose 0.004 cents.

The indicators are calculated in Excel, using the definitions explained previously in the Capital Budgeting chapter. As can be seen from the results, the income statement of the operating power plants show negative business results (NPV is negative), with respect to the relatively unfavourable current state of the input fuel prices and the selling prices of individual energy produced from the energy facility. This means that this project with the current input prices and a negative NPV does not generate more cash than needed to service the debt and to provide the required return to the shareholders.

The positive thing about the equipment (gas boilers and chillers) is that they have considerably longer service lifetime than covered by the economic calculation, usually up to thirty years. The economic calculation is limited to twenty years because after this period the cogeneration plant needs to be serviced. In this period there is a good probability that the input prices will change making the project more or less profitable. Then, the price of heat energy is provided by the state agencies and represents the minimum selling price of heat, which is not normally profitable for the manufacturer, but it is acceptable to the consumers which use this source of energy. That is the reason the sensitivity analysis on the changes of the input prices of the gas and the electricity is done.

The trigeneration plant with additional elements for production of heat and cooling on top of the generation of electricity considerably increases the value of the investment, but the biggest source of revenue is from the sale of electricity in terms of exploitation of the primary energy source –natural gas with high efficiency. The current market prices for electricity show that the yearly prices have a declining tendency. This is a result of the decrease of the prices of gas worldwide and the larger share of electricity coming from renewables.

4.7 Sensitivity Analysis

The sensitivity analysis is a technique used to determine how different values of an independent variable will impact a particular dependent variable under a given set of assumptions. This technique is used within specific boundaries that will depend on one or more input variables, such as the effect that changes in electricity prices or the gas prices will have on a NVP of the project. The trigeneration power plant is very dependent in three major categories, so the sensitivity analysis will check how much the input price of the electricity and the natural gas and the value of the WACC have impact on the profitability in general and the success of the project is created. I took the range of ± 30 % as an offset value for the values of the WACC, the purchase price of the natural gas and the sales price of the electricity as three different scenarios that influence the profitability or loss generated by the project.

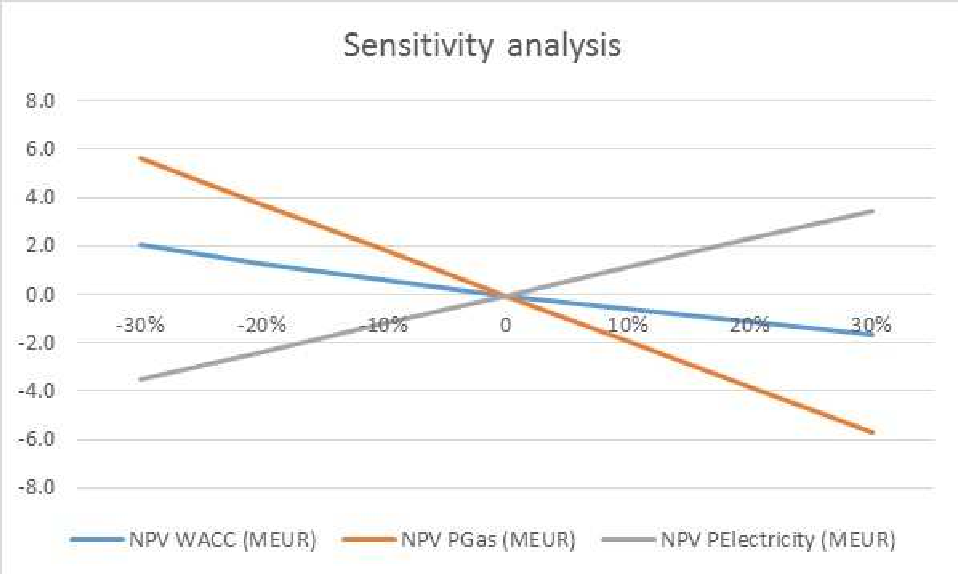
In the first case, I calculated the values of the ± 10 %, ± 20 % and ± 30 % cost of capital. The present capital investment planning ensures the continuing functionality of equipment and facilities. Deviations from the planned values can occur due to unforeseen equipment or machinery breakdown greater than anticipated wear of the assets. The risk of occurrence of these events is relatively small, since continuous monitoring and control of equipment and facilities is planned. In the second scenario the changes of the biggest cost of the project are taken, or the cost of input fuels and natural gas as a variable. The costs of natural gas are very volatile and the prices have a tendency of declining lately. The range from 0.178 EUR/Nm^3 to 0.328 EUR/Nm^3 or the current price is taken. In the third scenario, changes in electricity sale prices are taken as a variable that influences the revenues of the project, while the other variables are kept constant. The price of electricity is also very volatile on the market and depends on the market conditions. In the first quarter of 2016, the prices of electricity were very low, but in the second quarter they are rising. To check the impact, the range from 0.08EUR to 0.042EUR or the current price is taken. Figure 17 shows the chart of the sensitivity analysis.

Table 18: Sensitivity Analyses of WACC, Prices of Natural Gas and Electricity

Range	**WACC**	**NPV WACC (MEUR)**	**Purch. price of gas**	**NPV PGas (MEUR)**	**Sales Price of electicity**	**NPV PElectricity (MEUR)**
-30%	4.90%	2.019	0.178	5.607	0.029	-3.535
-20%	5.60%	1.266	0.203	3.723	0.034	-2.369
-10%	6.30%	0.580	0.228	1.838	0.038	-1.204
0%	7.00%	-0.046	0.253	-0.046	0.042	-0.046
10%	7.70%	-0.620	0.278	-1.931	0.046	1.127
20%	8.40%	-1.146	0.303	-3.815	0.050	2.292
30%	9.10%	-1.628	0.328	-5.700	0.055	3.458

It can be concluded from Table 18 and Chart 17 that if the WACC of the project is decreased by 10 %, the project generates positive cash flows that are sufficient to cover the operating expenses and have a positive NPV and return of the investment up to 15 years. If the WACC is increased, the project and all indicators become negative.

Figure 17: Sensitivity Analysis on the Changes of the WACC, Gas and Electricity Prices



It can be concluded from Table 18 and Chart 17 that if the price of the input fuel –natural gas, decreases below 0.228EUR/Nm^3 the project generates positive cash flows that are sufficient to cover the operating expenses and have a positive NPV and return of the investment up to 15 years. If the price of natural gas increases above 0.228EUR/Nm^3 the NPV of the project will be negative and all other indicators become negative. This analysis shows that any decrease of the price of 0.05 EUR/Nm^3, leads to an increase of the profitability on the project of 355,768 EUR.

For the third scenario, it can be concluded from Table 18 and Chart 17 that if the price of the electricity is increased the profitability of the project will also increase. Also Figure 17 shows that if the price increases above 47 cents/kWh the NPV, the IRR, MIRR of the project become positive, and the whole project payback period is below 15 years. For every 0.01 EUR further in increase of the price, the profitability is increased by 264,016 EUR.

It must be noted that the analysis of sensitivity is made by changing only one variable where all other variables remain constant. The analysis above for the three parameters shows that the profitability of the project is highly sensitive to changes and that the project is becoming unacceptable or unprofitable with even small changes.

5 FINANCIAL ANALYSIS ON THE DATA BASED IN SLOVENIA

This chapter covers the comparative analysis of the trigeneration power plant in Slovenia. I explain the market condition and the subsidized system for purchase of the electricity produced from cogeneration. The input price analysis provides the input parameters that are used in the economic analysis of the trigeneration model, calculated in Equation 16 where the WACCs is 4%. The capital budgeting indicators are calculated and a summary of the results is given.

5.1 Market Conditions in Slovenia

In Slovenia the electricity market consists of the wholesale and retail market. In the retail market, suppliers and traders conclude open contracts, in which the quantities of supplied electricity and the time profile of supply are not set in advance. Consumers pay for the supplied electricity according to actual consumption. The company Borzen d.o.o. is the electricity market operator and is, according to the Energy Act, mandated to record all contracts concluded on the organized market: purchased or sold in Slovenia, or transferred across the regulated area. In addition, Borzen in the form of operational schedules of production and consumption keeps the records of the contracts between the suppliers, customers and electricity producers.

In Slovenia, the Centre for RES/CHP administers the electricity feed-in support scheme for RES (renewable energy source) and CHP (high-efficiency cogeneration) power plants. The feed-in scheme is a support system which subsidizes and advances the usage of renewable technologies for the production of electricity. According to Borzen, till June 30 2016, the feed-in system includes 3700 power plants with a combined installed capacity of 500 MW. The feed-in scheme is financed through dedicated add-on charges on the network fee bills of all users of electricity in Slovenia. The owners of the power plant can choose between two types of support:

- "Guaranteed purchase", where CP takes over the electricity from the power plant and sells it to the market (the producer is thus included in the special balance group, operated by CP)
- "Operating premium", where the producer sells its energy on the market while CP only pays a premium as a difference between the full ("guaranteed purchase") price and the market price, which is determined ex ante or based on forecasts rather than actual results, on a yearly level, based also on plant type.

CHP producers with installed capacity over 1MW can only receive the "operating premium" type of support. The feed-in system must guarantees the origin of the CHP production, so all producers included in the scheme must provide guarantees of origin as proof. Regarding the support type, there is a marked increase toward “operational support”, since the trend is that the producers chose this type instead of the classic feed-in (guaranteed purchase). The total electricity production within the support system increased by 8% compared to the same period in 2014. The difference in support payments was +12% as well. The support payments in the period from 2012 to 2015 are shown in Table 19. In 2015, the fossil fuel CHP power plants in the feed in system have the biggest percentage of the support share of 34.5%, which is a small increase from 2014. The support paid per unit type is shown in Table 20.

Table 19: Support Payments in Slovenia for Periods from 2012 to 2015

Period	2015	2014	2013	2012
Electricity production (kWh)	980,813,221	907,157,333	802,889,085	653,969,311
Support payment (EUR)	147,094,948	130,882,180	118,515,291	89,777,431
Average support (EUR/kWh)	0.14997	0.14428	0.14761	0.13728

Source: 2016, Slovenian feed-in support system for electricity from RES
and high-efficiency CHP, p.2, Table 1

Table 20: Support Payments in Slovenia in 2015, by Unit Type

Power plant type	Electricity produced	Electricity share	Support Share
Biogas	17,932,957	12.20%	13.00%
Other	1,082,613	0.70%	0.40%
Wood biomass	17,362,521	11.80%	12.20%
Hydropower	7,256,019	4.90%	12.20%
Solar PV	68,101,165	46.30%	27.10%
Fossil fuel CHP	35,010,647	23.80%	34.50%
Wind	349,026	0.20%	0.60%
Total	147,094,948	100.00%	100.00%

Source: 2016, Slovenian Feed-in Support System for Electricity from RES
and High-efficiency CHP, p. 3, Table 2

5.2 Analysis of Input and Output Prices in Slovenia

5.2.1 Purchase prices of natural gas in Slovenia

According to the Agency of Energy in Slovenia, the Slovenian gas transmission network has 1121 kilometres of pipelines, compressor stations in Kidričevo and Ajdovščina, 246 metering-regulation stations and other stations and around 300 measurements points. The central part of the network includes pipeline M1 from Ceršak to Rogatec, M2 from Rogatec through Podlog to Vodice and M4 from Roden to Novo Mesto with a nominal pressure 50 bars, and the pipeline M3 from Šempeter near Nova Gorica to Vodice with a nominal pressure 67 bars. These pipelines provide reliable supply of natural gas. The gas transmission network is connected with the Austrian, Italian and Croatian networks and is an integral part of the pan-European gas transmission system. The natural gas prices for industry by standard consumer (annual consumption), half-year, unit and price are shown in the Table 23. In the thesis, the gas prices are taken for the customer group from 100,000 to 1,000,000 MWh or the average for 2015 is 0.4005EUR/Nm^3 for Slovenia are used in the calculations.

Table 21: Natural Gas Prices for Industry in Slovenia

	2015H1		2015H2		2015 Average	
	EUR / GJ	EUR / Nm^3	EUR / GJ	EUR / Nm^3	EUR / GJ	EUR / Nm^3
I1 (<1000 GJ)	17.6623	0.6681	17.0559	0.6452	17.3591	0.65665
I2 (1000 to <10000 GJ)	16.8824	0.6386	17.4159	0.6588	17.1492	0.6487
I3 (10000 to <100000 GJ)	12.4417	0.4707	12.8986	0.4879	12.6702	0.4793
I4 (100000 to <1000000GJ)	11.0122	0.4166	10.1612	0.3844	10.5867	0.4005
Slovenia	11.8187	0.4471	11.3845	0.4307	11.6016	0.4389

Source: Statistical Office of the Republic of Slovenia, 2016.

5.2.2 Purchase price of electricity in Slovenia

According to the Ministry of Infrastructure and Spatial Planning, Energy Directorate in Slovenia, the electricity prices (including VAT) for the industry are shown in the Table 22:

Table 22: Electricity Prices for Industry in Slovenia in EUR/kWh

	2015 H1	2015 H2	2015 average
ID (2000 to <20000 MWh)	0.0882	0.0919	0.0901
IE (20000 to <70000 MWh)	0.078	0.0808	0.0794
IF (70000 to <=150000 MWh)	0.0775	0.0761	0.0768
Slovenia	0.096	0.0969	0.0965

Source: Statistical Office of the Republic of Slovenia, 2016.

The industry electricity prices in the range from 20,000 to 70,000 MWh or the average for 2015 of 0.0794 EUR for MWh are used in the calculations in this thesis.

5.2.3 Sales price of electricity in Slovenia

In accordance with Article 26 of the Rules for the operation of the Centre for RES/CHP support (Official Gazette RS no. 86/09 and 17/14 – EZ-1; hereinafter: Rules) Borzen can sell the electricity from the EKO Group directly on the market or indirectly by transferring the whole EKO group to another Balance Scheme Member's balancing group or subgroup. In the previous year, Borzen sold the electricity from the EKO Group directly on the market but from 2016, the electricity from the Eco group is sold indirectly by transferring the whole EKO group to another Balance Scheme Member's balancing group.

In 2016 Borzen in its capacity as the Centre for RES/CHP Support, carried out the Auction on November 24, 2015 for the transfer of the whole Eco Group generated energy in 2016 according to the Rules for the Transfer of the ECO Group – Centre for RES/CHP Support.

There were 4 participants at the Auction, of which 3 from Slovenia and one from abroad. In the auction, the final price achieved was 41.13 €/MWh.

5.2.4 Sales prices for heating and cooling in Slovenia

The Energy Agency in Slovenia must be notified if a company wants to carry out heat distribution as an optional local service of general economic interest, or as commercial distribution. If the distributor supplies or intends to supply more than one hundred household customers, the district heating and cooling is provided as a service of general economic interest. District heating and cooling systems must be efficient. Heat distributors must ensure an annual level of heat by using at least one of the following sources:

- at least 50% of heat produced from renewable energy sources;
- at least 50% of waste heat;
- at least 75% of cogenerated heat; or
- at least 75% of a combination of the heat referred to in the above three indents.

The market for heating in Slovenia is regulated. The price regulation method is carried out on the basis of:

- the Price Control Act;
- twelfth indent of Article 2 of Decree supplementing the Decree laying down the list of goods and services subject to price control measures;
- the methodology for determining the price of heat for district heating as defined in the

Decree setting prices for the generation and distribution of steam and hot water in district heating for tariff customers, which entered into force on 23 April 2014 and is valid for 12 months. The regulated price is also the one that is charged by the regulated heat producer for heat production – means any legal or natural person that supplies heat to a heat distributor providing services of general economic interest and is connected to the distributor through an equity stake, or sells to the distributor more than 30% of the total amount of heat planned for the following year's distribution. The following Table 23 presents the retail price of heating for 2015:

Table 23: Retail Price of Heat for Standard Consumer in Households, Slovenia

Retail price of heat for selected standard consumer in households (EUR/MWh) by CITY and MONTH												
	2015 M01	2015 M02	2015 M03	2015 M04	2015 M05	2015 M06	2015 M07	2015 M08	2015 M09	2015 M10	2015 M11	2015 M12
SLOVENIA	60.13	58.51	57.91	56.37	52.55	49.64	54.01	54.18	54.36	58.81	58.57	58.90
Ljubljana	61.33	60.46	59.84	60.53	61.48	61.48	61.72	61.71	61.71	61.71	61.56	61.56

Source: Statistical office of the Republic of Slovenia, 2016

The heating price as the average of the monthly prices for the period of the year 2015 or 56.16EUR/MWh for Slovenia is used in the calculations in this thesis. For the cooling, I will use the same method for calculating the output price as used in the Macedonian model. The calculated price for cooling is 62.3 EUR/MWh.

5.3 Calculation of the Financial Analysis of the Investment in Slovenia

In the comparison analysis, the model used for the calculations in Skopje is modified according to the local purchase/sales prices. The income tax or the tax on profit in Slovenia is 17%, compared to the 10% in Macedonia. As input prices in the model, I used the input prices shown in Table 24.

Table 24: Sales and Purchase Prices in Slovenia

Type	**Price EUR**
Sales price for electricity	0.06210
Sales price for heating	0.05616
Sales price for cooling	0.0623
Purchase price for gas	0.40050
Purchase price for electricity	0.04113

Table 24 shows that the sales price of electricity in the support model is considerably lower compared to the price in Macedonia. The model is calculated based on the demand and supply shown in Table 4 and the input prices shown in Table 24. The effects on the calculated model are shown in Table 25. The detailed model is shown in Appendix D – The summary of the supply and demand model in Slovenia, per month.

Table 25: Summary of Supply and Demand Model in Slovenia, in EUR

Sales revenues		3,598,954
Sale of electricity	€	1,639,538
Sale of heating	€	1,252,267
Heat fix part	€	194,811
Sale of cooling	€	296,098
Cool Fix part	€	216,240
Production costs		3,094,201
Natural gas	€	2,849,698
Electricity	€	11,269
Service costs CHP1	14€/h	94,629.00
Service costs CHP2	14€/h	70,344.00
Service costs CHP3	14€/h	68,261.00

Table 26: Summarized Revenues and Cost Projections for Slovenia, (000 EUR)

	2016	2017-2025	2026	2027-2030	2031	2032-2034	2035
REVENUES	3599	…	3599	…	3599	…	3599
Revenues from energy	3599	…	3599	…	3599	…	3599
COGS	3933	…	3831	…	3588	…	3588
Cost of materials	3140	…	3140	…	3140	…	3140
Cost of gas and elect.	3094	…	3094	…	3094	…	3094
Other material costs	46	…	46	…	46	…	46
Cost of services	792	…	690	…	447	…	447
Maintenance costs	48	…	48	…	48	…	48
Cost of insurance	42	…	42	…	42	…	42
Depreciation	577	…	475	…	232	…	232
Labour costs	72	…	72	…	72	…	72
Administrative costs	53	…	53	…	53	…	53
GROSS PROFIT (LOSS)	-334	…	-232	…	11	…	11
Financial income	0		0		0		0
Financial expenses	0		0		0		0
TOTAL PROFIT (LOSS)	-334	…	-232	…	11	…	11

The model on Table 25 shows that the project is generating just enough revenues to cover its COGS. However, the Revenue and cost projections need to be checked whether the project can carry the operational costs as well.

The summarized revenue and cost projections in Slovenia are shown in Table 26. The detailed revenue and cost model for Slovenia per month is shown in Appendix E. From the revenue and cost projections can be seen that the yearly total profit is actually a loss in the first 15 years and the project cannot carry its operational expenditures and thus it is unprofitable.

Table 27 shows the cash flow statement for the project in Slovenia. The detailed Cash flow statement for Slovenia per month is shown in Appendix F. In Table 27, the purchase price of the asset or the initial investment is shown in year zero. In the cash flow, the residual costs are added in the last year. Unfortunately, the loss over the years is too large for this addition of 1.286 thousands EUR to make a difference. If we summarize all cash flows from year zero - 2015 until 2035, than the cash generated from the project is negative 4,443 thousands EUR. Also, if we include the time value of money, the yearly net cash flows are used to calculate the PV of the Cash flows. The sum of all PV positive cash flows from 2016 to 2035 is equal to 3,891 thousands EUR. The PV of the positive cash flows is less than the initial 10,591 negative cash flow, which makes the total cash flow negative.

Table 27: Summarized Cash Flow Statement of the Project in Slovenia, (000 EUR)

YEAR	2015	2016	2017-2034	2035
Cash at beginning of year	-10591	-10591	…	7729
Investments	-10591	0		0
Cash flow linked to operating costs	0	964	…	2251
Inflows	0	3253	…	4540
Revenues	0	3253	…	3253
Residual value	0	0	…	1286
Outflows	0	2289	…	2289
Cost of gas and electricity	0	2076	…	2076
Other material costs	0	46	…	46
Cost of maintenance	0	48	…	48
Cost of insurance	0	42	…	42
Labour costs	0	24	…	24
Administrative costs	0	53	…	53
Tax on profit	0	0		0
Financing activities	0	0		0
Net Cash flow	-10591	964	…	2251

The calculations of the capital budgeting indicators presented in Table 28 also show negative results. The Accounting rate of return or ARR is calculated based on the net cash flows shown in Table 27 on page 68 for 20 year period. The ARR is calculated in Excel by substituting the value for the amount received and amounts invested in Equation (5). Accounting rate of return is 2.9%. The ARR does not meet the criteria to be bigger than the discount rate. The payback period is calculated on the basis of cash flows data in Table 27, using Equation (6) on page 13. The Payback period is 45 years, which does not meet the criterion to be less than 15 years. The NPV is determined on the basis of the previously calculated WACCs in Equation 16, which is 4%. The cash flows for a period of twenty years are used, shown in Table 27 on page 68 to calculate the Net present using Equation (7) from page 14. The calculated NPV is -6.7 million EUR. To accept the project the NPV should always be positive. In our case the NPV tells us that the project will not generate cash, but will lose cash for the investors. The IRR is calculated based on the cash flows shown in Table 27 on page 68, using Equation (9) from page 15. The calculated IRR is a negative 4.01%. For a positive decision, the expected value was supposed to be bigger than the WACC. With the cash flows from Table 27, and Equation (12) the MIRR can be calculated. The calculation shows that the MIRR is a negative 1.08%. The MIRR and the IRR are both less than the cost of capital WACCs, which means that the project is not acceptable. The PI is calculated based on the cash flows from Table 27, and Equation (13) on page 17. The project is acceptable if the PI is greater than one. In our case the PI is 0.367 which is less than one. By calculating the PI-1, in our case, for every one euro invested in the project, we would lose 0.633 cents.

Table 28: Static and Dynamic Capital Budgeting Indicators in Slovenia

Dynamic ratios	Value	Decision criteria	Decision
Discount rate	4.00%		
Reinvestment rate	4.00%		
NPV (MEUR)	-6.7	Positive	No
IRR (in%)	-4.01%	Bigger than WACC	No
MIRR (in%)	-1.08%	Bigger than WACC	No
Payback period	44.57	Less than 15 years	No
Profitability index	0.367	Bigger than 1	No
Profitability index -1	-0.633	We lose x EUR/ EUR invested	No
AAR	2.90%	Bigger than WACC	No

The financial calculation of the trigeneration power plant in Slovenia shows negative business results with respect to the market conditions in Slovenia. The project with the current market prices for electricity, as being in the Support system for CHP power plants that operate above 4000h, and the price of the natural gas, is unprofitable and unacceptable for future investors. The prices taken in the calculations do not consider any additional subsidies that the plant might be eligible for and the effect of the subsidies is not presented in the model.

CONCLUSION

The following points are concluded:

- The trigeneration power plant that uses natural gas differs from other conventional power plants because the environmental impact is significantly reduced when burning gas. In the burning of gas there are no SO2 and NOx by-products, which eliminates the net greenhouse gas additions to the environment. Also, there is no sludge, so no additional impact on the soil. Currently, in Macedonia more than 70% of electricity is produced from thermal power plants that use coal as input fuel, which pollutes the environment. Substituting them with electricity from cogeneration will have huge positive impacts on the environment. When making a strategic decision, the protection of the environment is a significant factor that cannot be ignored.
- The investment in a trigeneration power plant at the moment is very high. This is partly because the cooling technology is relatively new on the market and produced by only a few manufacturers. In the future, with the adoption and development of the technology, the prices of the investment should decrease.
- The trigeneration power plant is efficient only if it effectively uses its input fuel, natural gas. This means that the power plant needs to operate above 4500h to be most efficient. Heating and cooling are seasonal so the investor needs to find customers for heating and for cooling. Our project can be based in Macedonia or in Slovenia, where the climate

conditions are rather similar. The demand for heating and cooling in a business centre the size of ERA city would make it an excellent customer. That is why when sizing a power plant, the demand of the complex is considered the most important criteria. The energy supply should be dimensioned so that at any time they satisfy the needs of the complex and at the same time they are not unnecessarily oversized. Additionally, the excess energy produced can be offered to other customers and increase the profitability of the power plant.

- The policies in EU and the world after 1997 regarding the percentage of cogeneration in energy efficiency targets, set clear goals that all counties must reach and, if possible, exceed.
- Macedonia failed to transpose Directive 2009/28/EC on time. This makes Macedonia the only county in Europe where the customers cannot choose their energy supplier. Currently there are only a few cogeneration power plants in Macedonia, but they are used as reserve for a very low number of hours and that is why they are neither efficient nor profitable.
- The price of natural gas on the world market at the moment is extremely high and is very dependent on politics. In the last few years we have witnessed a collapse of the crude oil prices, but the same effect did not happen to gas prices, which remained quite steady with small ups and downs. The result of this is having to currently pay premium prices on both the Macedonian and Slovenian markets.
- The prices of crude oil and gas became even more unstable with the vote of the United Kingdom to exit the EU. It is too early to predict how this will affect the prices.
- The market conditions on the energy market in Macedonia are not good. At the moment the market is heavily price regulated and the wholesale price regulation must be eliminated without delay. MEPSO and EVN as network operators also have to become more transparent towards the producers of renewable energy with regard to information on the estimated costs and timeframe for connections. ERC has to ensure that rules for connection and access to the networks are implemented in a non-discriminatory and objective way. In June 2016, MEPSO signed the agreement with SEE CAO is a regional auction house that will facilitate and organize auctions for leasing power line capacity for cross-border electricity transmission starting from 2017.
- The economic analysis of the project was made under a few assumptions: the discount rate is 7% in Macedonia and 4% in Slovenia, the lifespan of the project is 20 years, the input prices do not change in the period of analysis and the demand for electricity, heating and cooling energy also remains constant during the years.
- Based on the current market prices, the project in Macedonia is not profitable. The project capital budgeting ratios are negative.
- The three biggest variables that make or break this project are the WACC, the input purchase price of natural gas and the selling price of electricity. The sensitivity analysis in this thesis shows that further decrease of the WACC has positive impact on the project profitability. Its NPV turns positive and the payback period is below 15 years. Also, the sensitivity analysis in this thesis shows that further decrease of the price of gas, from 0.25

to 0.175 EUR/m^3 and lower can provide positive yearly cash flows and positive *IRR*, *MIRR* and Return of investment under 15 years. Any decrease of the price of gas of 0.05EUR/m3 increases the profitability of the project by 355,768 EUR. Also, if the price of electricity increases by 50% or from 4 cents/kWh to 6.5 cents/kWh or more, the *NPV*, *IRR* and *MIRR* of the project become positive, and the whole project *payback period* is less than 15 years. Every 0.01 EUR further increase of the price, increases profitability by 264,016 EUR.

- If the output electricity price from trigeneration is subsidized by the government as was the initial plan, the project is acceptable according to the current market prices.
- In Slovenia, the trigeneration and cogeneration power plants sign a contract with Borzen, the Slovenian electricity market operator and get in the feed in system that is regulated by Borzen. The CHP that operate above 4000h choose the Operation premium support. This means that they become part of the EKO Group producers. They are not allowed to sell additional power to other buyers. Borzen organizes auctions and sells the yearly planned production of electricity of the whole EKO Group. According to the achieved price, the producers are entitled to an Operational support plan which they get for every kWh which is produced according to the rules specified the contract.
- With the current market prices, the economic analysis in Slovenia showed that the revenue generated covers the COGS, but not the operational costs. In total, the project was not profitable and all the indicators are negative as well.
- In both countries, increase of the selling price of electricity and decrease of the purchase price of gas will give more favourable results for future investors.

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APPENDICES

LIST OF APPENDICES

Appendix A - List of Abbreviations

AVC	Average Variable Costs
BCHP	Building Cooling, Heating and Power
CAPM	Capital Asset Pricing Model
CFC	Chlorofluorocarbon
CFCD	Central Financing and Contracting Department
CHCP	Combined Heating, Cooling and Power
CHP	Combined Heating and Power
CM	Contribution Margin
EU	European Union
FC	Fixed Costs
FELU	Faculty of Economics
HCFC	Hydro-chlorofluorocarbons
IEA	International Energy Agency
IRR	Internal Rate of Return
Ktoe	Kiloton
MIRR	Modified Internal Rate of Return
NF	National Fund
Nm3	Normal Cubic Meter
NOPAT	Net Operating Cash Flow After taxes
NOWC	Net Operation Working Capital
NREAP	National Renewable Energy Action Plans
NVP	Net Present Value
PI	Profitability Index
PV	Present Values
Q	Quantity
Rules	Rules for the Operation of the Centre for RES/CHP Support
USD/bbl	USD/barrel
USD/mmBTU	USD/ million British thermal units
VC	Variable Costs
WACC	Weighted Average Cost of Capital
$WACC_M$	WACC of the project in Macedonia
$WACC_S$	WACC of the project in Slovenia

Appendix B: Supply and Demand Model in Macedonia, Per Month

Quantities Supply / Demand	Unit of measure	Jan.	Feb.	Mar.	Apr.	May	June
Sale of electricity	**kWh**	3,334,699	2,808,410	2,372,116	1,227,337	911,368	1,589,623
Sale of heat	**kWh**	3,694,611	3,019,478	2,469,600	1,299,383	568,670	147,727
Sale of cool	**kWh**	0	0	0	29,122	351,888	1,054,955
Consumption of Nat. gas	**Sm3**	897,294	745,251	619,797	328,179	254,324	421,901
Consumption of electricity	**kWh**	19,744	16,191	14,610	12,380	18,478	31,765
Working hours CHP 1	**Hour**	741	668	722	518	368	383
Working hours CHP 2	**Hour**	694	624	491	184	108	281
Working hours CHP 3	**Hour**	640	508	440	221	166	292
Sale revenues							
Sale of electricity	**€**	140,198	118,071	99,729	51,600	38,316	66,831
Sale of heating	**€**	232,160	189,736	155,183	81,650	35,734	9,283
Heating fix part	**€**	16,234	16,234	16,234	16,234	16,234	16,234
Sale of cooling	**€**	0	0	0	2,031	24,544	73,583
Cooling fix part	**€**	18,020	18,020	18,020	18,020	18,020	18,020
Production costs							
Natural gas	**€**	226,538	188,152	156,479	82,855	64,209	106,516
Electricity	**€**	3,328	2,729	2,463	2,087	3,115	5,355
Service costs CHP1	***14€/h***	10,374.00	9,352.00	10,108.00	7,252.00	5,152.00	5,362.00
Service costs CHP2	***14€/h***	9,716.00	8,736.00	6,874.00	2,576.00	1,512.00	3,934.00
Service costs CHP3	***14€/h***	8,960.00	7,112.00	6,160.00	3,094.00	2,324.00	4,088.00

(table continues)

(continues)

Quantities Supply / Demand	Unit of measure	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year
Sale of electricity	**kWh**	2,355,552	1,905,260	997,986	1,790,575	3,348,539	3,760,109	30,635,603
Sale of heating	**kWh**	45,033	93,346	695,287	1,774,637	3,778,173	4,711,587	22,297,532
Sale of cooling	**kWh**	1,628,697	1,299,656	293,785	91,665	0	0	9,726,222
Consumption of Nat. gas	**Sm3**	617,458	501,910	271,162	473,766	909,162	1,075,148	7,240,984
Consumption of electricity	**kWh**	43,894	36,898	16,874	15,245	20,241	27,654	1,637,535
Working hours CHP 1	**Hour**	502	422	419	608	720	744	6,815
Working hours CHP 2	**Hour**	440	349	128	345	680	742	5,066
Working hours CHP 3	**Hour**	432	362	183	312	654	706	4,916
Sale revenues								3,253,440
Sale of electricity	**€**	99,032	80,101	41,957	75,280	140,780	158,083	1,109,977
Sale of heating	**€**	2,830	5,866	43,690	111,513	237,410	296,064	1,401,118
Heating fix part	**€**	16,234	16,234	16,234	16,234	16,234	16,234	194,811
Sale of cooling	**€**	113,601	90,650	20,491	6,394	0	0	331,294
Cooling fix part	**€**	18,020	18,020	18,020	18,020	18,020	18,020	216,240
Production costs								2,075,815
Natural gas	**€**	155,888	126,716	68,460	119,611	229,534	271,440	1,796,397
Electricity	**€**	7,399	6,220	2,844	2,570	3,412	4,662	46,184
Service costs CHP1	***14€/h***	7,028.00	5,908.00	5,866.00	8,512.00	10,080.00	10,416.00	94,629.00
Service costs CHP2	***14€/h***	6,160.00	4,886.00	1,792.00	4,830.00	9,520.00	10,388.00	70,344.00
Service costs CHP3	***14€/h***	6,048.00	5,068.00	2,562.00	4,368.00	9,156.00	9,884.00	68,261.00

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 25, Table 4

Appendix C: Revenues and Costs of the Project in Macedonia from 2016-2035, in EUR

	2016	2017	2018	2019	2020
REVENUES	3253440	3253440	3253440	3253440	3253440
Revenues from energy	3253440	3253440	3253440	3253440	3253440
COGS	2866287	2866287	2866287	2866287	2866287
Cost of materials	2122095	2122095	2122095	2122095	2122095
Cost of gas and elect.	2075815	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280	46280
Cost of services	744191	744191	744191	744191	744191
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	577072	577072	577072	577072	577072
Labour costs	24099	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	387154	387154	387154	387154	387154
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	387,153.58	387154	387154	387154	387154

(table continues)

(continues)

	2021	2022	2023	2024	2025
REVENUES	3253440	3253440	3253440	3253440	3253440
Revenues from energy	3253440	3253440	3253440	3253440	3253440
COGS	2866287	2866287	2866287	2866287	2866287
Cost of materials	2122095	2122095	2122095	2122095	2122095
Cost of gas and elect.	2075815	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280	46280
Cost of services	744191	744191	744191	744191	744191
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	577072	577072	577072	577072	577072
Labour costs	24099	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	387154	387154	387154	387154	387154
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	387154	387154	387154	387154	387154

(table continues)

(continues)

	2026	2027	2028	2029	2030
REVENUES	3253440	3253440	3253440	3253440	3253440
Revenues from energy	3253440	3253440	3253440	3253440	3253440
COGS	2763959	2763959	2763959	2763959	2763959
Cost of materials	2122095	2122095	2122095	2122095	2122095
Cost of gas and elect.	2075815	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280	46280
Cost of services	641863	641863	641863	641863	641863
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	474744	474744	474744	474744	474744
Labour costs	24099	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	489482	489482	489482	489482	489482
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	489482	489482	489482	489482	489482

(table continues)

(continues)

	2031	2032	2033	2034	2035
REVENUES	3253440	3253440	3253440	3253440	3253440
Revenues from energy	3253440	3253440	3253440	3253440	3253440
COGS	2521292	2521292	2521292	2521292	2521292
Cost of materials	2122095	2122095	2122095	2122095	2122095
Cost of gas and elect.	2075815	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280	46280
Cost of services	399197	399197	399197	399197	399197
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	232078	232078	232078	232078	232078
Labour costs	24099	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	732148	732148	732148	732148	732148
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	732148	732148	732148	732148	732148

Appendix D: Cash Flow Statement in Macedonia, in EUR

YEAR	2015	2016	2017	2018
Cash at beginning of year	-10591280	-10591280	-9627054	-8662828
Investments	-10591280	0	0	0
Cash flow linked to operating costs	0	964226	964226	964226
inflows	0	3253440	3253440	3253440
Revenues	0	3253440	3253440	3253440
Residual value	0	0	0	0
outflows	0	2289214	2289214	2289214
Cost of gas and electricity	0	2075815	2075815	2075815
Other material costs	0	46280	46280	46280
Cost of maintenance	0	47698	47698	47698
Cost of insurance	0	42365	42365	42365
Labour costs	0	24099	24099	24099
Administrative costs	0	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	-10591280	964226	964226	964226

(table continues)

(continues)

YEAR	2019	2020	2021	2022
Cash at beginning of year	-7698603	-6734377	-5770151	-4805925
Investments	0	0	0	0
Cash flow linked to operating costs	964226	964226	964226	964226
inflows	3253440	3253440	3253440	3253440
Revenues	3253440	3253440	3253440	3253440
Residual value	0	0	0	0
outflows	2289214	2289214	2289214	2289214
Cost of gas and electricity	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365
Labour costs	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	964226	964226	964226	964226

(table continues)

(continues)

YEAR	2023	2024	2025	2026
Cash at beginning of year	-3841699	-2877473	-1913248	-949022
Investments	0	0	0	0
Cash flow linked to operating costs	964226	964226	964226	964226
inflows	3253440	3253440	3253440	3253440
Revenues	3253440	3253440	3253440	3253440
Residual value	0	0	0	0
outflows	2289214	2289214	2289214	2289214
Cost of gas and electricity	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365
Labour costs	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	964226	964226	964226	964226

(table continues)

(continues)

YEAR	2027	2028	2029	2030
Cash at beginning of year	15204	979430	1943656	2907882
Investments	0	0	0	0
Cash flow linked to operating costs	964226	964226	964226	964226
inflows	3253440	3253440	3253440	3253440
Revenues	3253440	3253440	3253440	3253440
Residual value	0	0	0	0
outflows	2289214	2289214	2289214	2289214
Cost of gas and electricity	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365
Labour costs	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	964226	964226	964226	964226

(table continues)

(continues)

YEAR	2031	2032	2033	2034	2035
Cash at beginning of year	3872107	4836333	5800559	6764785	7729011
Investments	0	0			
Cash flow linked to operating costs	964226	964226	964226	964226	2250674
inflows	3253440	3253440	3253440	3253440	4539889
Revenues	3253440	3253440	3253440	3253440	3253440
Residual value	0	0	0	0	1,286,448
outflows	2289214	2289214	2289214	2289214	2289214
Cost of gas and electricity	2075815	2075815	2075815	2075815	2075815
Other material costs	46280	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Labour costs	24099	24099	24099	24099	24099
Administrative costs	52956	52956	52956	52956	52956
Tax on profit	0	0	0	0	0
Financing activities	0	0	0	0	0
Net Cash flow	964226	964226	964226	964226	2250674

Appendix E: The Supply and Demand Model in Slovenia, per Month

Quantities Supply / Demand	Unit of measure	Jan.	Feb.	Mar.	Apr.	May	June
Sale of electricity	**kWh**	3,334,699	2,808,410	2,372,116	1,227,337	911,368	1,589,623
Sale of heating	**kWh**	3,694,611	3,019,478	2,469,600	1,299,383	568,670	147,727
Sale of cooling	**kWh**	0	0	0	29,122	351,888	1,054,955
Consumption of Nat. gas	**Sm3**	897,294	745,251	619,797	328,179	254,324	421,901
Consumption of electricity	**kWh**	19,744	16,191	14,610	12,380	18,478	31,765
Working hours CHP 1	**Hour**	741	668	722	518	368	383
Working hours CHP 2	**Hour**	694	624	491	184	108	281
Working hours CHP 3	**Hour**	640	508	440	221	166	292
Sales revenues							
Sale of electricity	**€**	207,085	174,402	147,308	76,218	56,596	98,716
Sale of heating	**€**	207,489	169,574	138,693	72,973	31,937	8,296
Heating fix part	**€**	16,234	16,234	16,234	16,234	16,234	16,234
Sale of cooling	**€**	0	0	0	1,815	21,936	65,763
Cooling fix part	**€**	18,020	18,020	18,020	18,020	18,020	18,020
Production costs							
Natural gas	**€**	359,366	298,473	248,229	131,436	101,857	168,971
Electricity	**€**	812	666	601	509	760	1,306
Service costs CHP1	***14€/h***	10,374.00	9,352.00	10,108.00	7,252.00	5,152.00	5,362.00
Service costs CHP2	***14€/h***	9,716.00	8,736.00	6,874.00	2,576.00	1,512.00	3,934.00
Service costs CHP3	***14€/h***	8,960.00	7,112.00	6,160.00	3,094.00	2,324.00	4,088.00

(table continues)

(continues)

Quantities Supply / Demand	Unit of measure	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year
Sale of electricity	**kWh**	2,355,552	1,905,260	997,986	1,790,575	3,348,539	3,760,109	30,635,603
Sale of heating	**kWh**	45,033	93,346	695,287	1,774,637	3,778,173	4,711,587	22,297,532
Sale of cooling	**kWh**	1,628,697	1,299,656	293,785	91,665	0	0	9,726,222
Consumption of Nat. gas	**Sm3**	617,458	501,910	271,162	473,766	909,162	1,075,148	7,240,984
Consumption of electricity	**kWh**	43,894	36,898	16,874	15,245	20,241	27,654	1,637,535
Working hours CHP 1	**Hour**	502	422	419	608	720	744	6,815
Working hours CHP 2	**Hour**	440	349	128	345	680	742	5,066
Working hours CHP 3	**Hour**	432	362	183	312	654	706	4,916
Sales revenues								1,914,581
Sale of electricity	**€**	146,280	118,317	61,975	111,195	207,944	233,503	879,213
Sale of heating	**€**	2,529	5,242	39,047	99,664	212,182	264,603	623,267
Heating fix part	**€**	16,234	16,234	16,234	16,234	16,234	16,234	97,406
Sale of cooling	**€**	101,529	81,017	18,314	5,714	0	0	206,575
Cooling fix part	**€**	18,020	18,020	18,020	18,020	18,020	18,020	108,120
Production costs								1,781,215
Natural gas	**€**	247,292	201,015	108,600	189,743	364,119	430,597	1,541,367
Electricity	**€**	1,805	1,518	694	627	833	1,137	6,614
Service costs CHP1	***14€/h***	7,028.00	5,908.00	5,866.00	8,512.00	10,080.00	10,416.00	94,629.00
Service costs CHP2	***14€/h***	6,160.00	4,886.00	1,792.00	4,830.00	9,520.00	10,388.00	70,344.00
Service costs CHP3	***14€/h***	6,048.00	5,068.00	2,562.00	4,368.00	9,156.00	9,884.00	68,261.00

Source: Bas, D. at all *Feasibility study for the energy facility ERA City Skopje*, 2008, Page 25, Table 4

Appendix F: Revenues and Costs of the Project in Slovenia from 2016-2035, in EUR

	2016	2017	2018	2019	2020
REVENUES	3598908	3598908	3598908	3598908	3598908
Revenues from energy	3598908	3598908	3598908	3598908	3598908
COGS	3932871	3932871	3932871	3932871	3932871
Cost of materials	3140481	3140481	3140481	3140481	3140481
Cost of gas and elect.	3094201	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280	46280
Cost of services	792390	792390	792390	792390	792390
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	577072	577072	577072	577072	577072
Labour costs	72298	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT (LOSS)	-333963	-333963	-333963	-333963	-333963
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	-333,963	-333963	-333963	-333963	-333963

(table continues)

(continues)

	2021	2022	2023	2024	2025
REVENUES	3598908	3598908	3598908	3598908	3598908
Revenues from energy	3598908	3598908	3598908	3598908	3598908
COGS	3932871	3932871	3932871	3932871	3932871
Cost of materials	3140481	3140481	3140481	3140481	3140481
Cost of gas and elect.	3094201	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280	46280
Cost of services	792390	792390	792390	792390	792390
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	577072	577072	577072	577072	577072
Labour costs	72298	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	-333963	-333963	-333963	-333963	-333963
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	-333963	-333963	-333963	-333963	-333963

(table continues)

(continues)

	2026	2027	2028	2029	2030
REVENUES	3598908	3598908	3598908	3598908	3598908
Revenues from energy	3598908	3598908	3598908	3598908	3598908
COGS	3830543	3830543	3830543	3830543	3830543
Cost of materials	3140481	3140481	3140481	3140481	3140481
Cost of gas and elect.	3094201	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280	46280
Cost of services	690062	690062	690062	690062	690062
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	474744	474744	474744	474744	474744
Labour costs	72298	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	-231635	-231635	-231635	-231635	-231635
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	-231635	-231635	-231635	-231635	-231635

(table continues)

(continues)

	2031	2032	2033	2034	2035
REVENUES	3598908	3598908	3598908	3598908	3598908
Revenues from energy	3598908	3598908	3598908	3598908	3598908
COGS	3587876	3587876	3587876	3587876	3587876
Cost of materials	3140481	3140481	3140481	3140481	3140481
Cost of gas and elect.	3094201	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280	46280
Cost of services	447395	447395	447395	447395	447395
Maintenance costs	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Depreciation	232078	232078	232078	232078	232078
Labour costs	72298	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956	52956
GROSS PROFIT	11032	11032	11032	11032	11032
FINANCIAL INCOME	0	0	0	0	0
FINANCIAL EXPENSES	0	0	0	0	0
TOTAL PROFIT (LOSS)	11032	11032	11032	11032	11032

Appendix G: Cash Flow Statement in Slovenia, in EUR

YEAR	2015	2016	2017	2018
Cash at beginning of year	-10591280	-10591280	-10348171	-10105061
Investments	-10591280	0	0	0
Cash flow linked to operating costs	0	243109	243109	243109
inflows	0	3598908	3598908	3598908
Revenues	0	3598908	3598908	3598908
Residual value	0	0	0	0
outflows	0	3355799	3355799	3355799
Cost of gas and electricity	0	3094201	3094201	3094201
Other material costs	0	46280	46280	46280
Cost of maintenance	0	47698	47698	47698
Cost of insurance	0	42365	42365	42365
Labour costs	0	72298	72298	72298
Administrative costs	0	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	-10591280	243109	243109	243109

(table continues)

(continues)

YEAR	2019	2020	2021	2022
Cash at beginning of year	-9861952	-9618843	-9375733	-9132624
Investments	0	0	0	0
Cash flow linked to operating costs	243109	243109	243109	243109
inflows	3598908	3598908	3598908	3598908
Revenues	3598908	3598908	3598908	3598908
Residual value	0	0	0	0
outflows	3355799	3355799	3355799	3355799
Cost of gas and electricity	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365
Labour costs	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	243109	243109	243109	243109

(table continues)

(continues)

YEAR	2023	2024	2025	2026
Cash at beginning of year	-8889515	-8646406	-8403296	-8160187
Investments	0	0	0	0
Cash flow linked to operating costs	243109	243109	243109	243109
inflows	3598908	3598908	3598908	3598908
Revenues	3598908	3598908	3598908	3598908
Residual value	0	0	0	0
outflows	3355799	3355799	3355799	3355799
Cost of gas and electricity	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365
Labour costs	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	243109	243109	243109	243109

(table continues)

(continues)

YEAR	2027	2028	2029	2030
Cash at beginning of year	-7917078	-7673968	-7430859	-7187750
Investments	0	0	0	0
Cash flow linked to operating costs	243109	243109	243109	243109
inflows	3598908	3598908	3598908	3598908
Revenues	3598908	3598908	3598908	3598908
Residual value	0	0	0	0
outflows	3355799	3355799	3355799	3355799
Cost of gas and electricity	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365
Labour costs	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956
Tax on profit	0	0	0	0
Financing activities	0	0	0	0
Net Cash flow	243109	243109	243109	243109

(table continues)

(continues)

YEAR	2031	2032	2033	2034	2035
Cash at beginning of year	-6944640	-6701531	-6458422	-6215313	-5972203
Investments	0	0			
Cash flow linked to operating costs	243109	243109	243109	243109	1529558
inflows	3598908	3598908	3598908	3598908	4885356
Revenues	3598908	3598908	3598908	3598908	3598908
Residual value	0	0	0	0	1,286,448
outflows	3355799	3355799	3355799	3355799	3355799
Cost of gas and electricity	3094201	3094201	3094201	3094201	3094201
Other material costs	46280	46280	46280	46280	46280
Cost of maintenance	47698	47698	47698	47698	47698
Cost of insurance	42365	42365	42365	42365	42365
Labour costs	72298	72298	72298	72298	72298
Administrative costs	52956	52956	52956	52956	52956
Tax on profit	0	0	0	0	0
Financing activities	0	0	0	0	0
Net Cash flow	243109	243109	243109	243109	1529558