Technoeconomic analysis of a trigeneration system based on biomass gasification

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RESUMO

O objetivo deste estudo é avaliar a viabilidade técnica-económica de substituir gás natural (GN) por gás natural sintéctico (GNS) via gaseificação da biomassa, na central de trigeração Climaespaço. Esta central fornece calor e frio a edifícios do Parque das Nações em Lisboa, produzindo também eletricidade para consumo próprio e vendendo o excesso à rede elétrica. Para efetuar a análise técnica o sistema é modelado no EnergyPLAN. Vários cenários com diferentes percentagens de introdução de GNS são propostos e analisados em duas configurações distintas, na primeira o GNS substitui o GN na turbina a gás e na caldeira auxiliar e, na segunda o GNS só substitui o GN na turbina a gás, sendo a caldeira auxiliar substituída por uma caldeira de queima directa de biomassa. Para perceber o peso de cada categoria de custo é efetuada uma análise de custos. A viabilidade financeira do projeto baseia-se no cálculo do valor atual líquido (VAL) comparativo dos cenários propostos em relação ao cenário base. Finalmente é realizada uma análise de sensibilidade ao VAL de todos os cenários, variando os custos com maior impacto. Verifica-se que, com o aumento da capacidade de gaseificação a exportação de electricidade decresce e a importação aumenta. O VAL é negativo para todos os cenários e os maiores custos são os da biomassa. A diminuição do custo da biomassa e/ou o aumento do custo do GN torna alguns cenários viáveis financeiramente. Concluindo, a viabilidade deste tipo de projectos é muito dependente dos preços da biomassa e do GN.

Palavras-chave:

Planeamento Energético, Gaseificação de biomassa, Substituição de combustíveis fósseis, Trigeração

ABSTRACT

This study aims to evaluate the technoeconomic feasibility of replacing natural gas (NG) by bio synthetic natural gas (bio-SNG) produced from biomass gasification in the Climaespaço trigeneration plant. This plant supplies heating and cooling to the buildings in Parque das Nações, Lisbon, producing also power for own consumption and selling the excess to the grid. To carry out the technical analysis, EnergyPLAN is used to model the system. Several scenarios, according to the bio-SNG share, are proposed and analysed in two different system's configurations, one where the bio-SNG replaces the gas turbine and auxiliary boiler NG demand and, a second, where the bio-SNG only substitutes the NG in the gas turbine, being the NG auxiliary boiler substituted by a direct combustion biomass boiler. A cost analysis is carried out to show the weight of each cost associated with each scenario. A comparative net present value (NPV) analysis is performed for each proposed scenario in relation with the baseline scenario for assessing the financial viability of the project. A NPV sensitivity analysis for all the scenarios is studied by varying the parameters with more influence. Results show that with the increase of the gasification capacity, the electricity exportation decreases and the importation increases. The NPV is negative for all the scenarios and the biomass costs are the most impactful. Decreasing the biomass price and/or increasing the NG price turns some of the scenarios financially viable. In conclusion, the feasibility of this project is highly dependent on biomass and NG prices.

Keywords:

Energy planning, Biomass gasification, Fossil fuel replacement, Trigeneration

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NOMENCLATURE

Symbols

ABFC	Afterburning fuel consumption; Eq. 3	(GWh)
ABHP	Afterburning heat production; Eq. 3	(GWh)
CF	Cash flow; Eq. 4, 5	(€)
CHP PE	CHP power efficiency; Eq. 2	(-)
CHP TE	CHP thermal efficiency; Eq. 3	(-)
COP	Coefficient of Performance; Eq. 1	(-)
Costs	Total payments; Eq. 5	(€)
CP	Cooling production; Eq. 1	(GWh)
CRF	Capital Recovery Factor; Eq. 6	(-)
EI	Energy input; Eq. 1	(GWh)
EP	Electricity production; Eq. 2	(GWh)
THP	Total heat production; Eq. 3	(GWh)
N	Project lifetime; Eq. 4	(-)
NPV	Net Present Value; Eq. 4	(€)
r	Discount rate; Eq. 4, 6	(%)
Revenues	Positive income Eq. 5	(€)
t	Current year; Eqs. 4, 5, 6	(-)
TFC	Turbine fuel consumption; Eq. 2, 3	(GWh)
THP	Turbine heat production; Eq. 3	(GWh)

Acronyms

Bio-SNG – Bio Synthetic Natural Gas

CCHP – Combined Cooling Heat and Power

CHP – Combined Heat and Power

CO_2 – Carbon Dioxide

COP – Coefficient of Performance

DCF – Discounted Cash Flows

DH – District Heating

EU – European Union

EU ETS – European Union Emissions Trade System

GHG – Greenhouse Gases

IEO2016 – International Energy Outlook 2016

IPCC – International Panel on Climate Change

LHV – Lower Heating Value

NG – Natural Gas

O&M – Operation and Maintenance

OECD – Organisation for Economic Co-Operation and Development

PB – Payback Period

PES – Primary Energy Savings

RE – Renewable Energy

RES – Renewable Energy Sources

SES – Smart Energy Systems

SNG – Synthetic Natural Gas

1. INTRODUCTION

1.1. MOTIVATION

Planet Earth is getting hotter and one of the obvious causes is the increase of emissions of greenhouse gases (GHG) that intensifies the greenhouse effect. The emissions of GHG and the consequences to the global warming are matter of great concern.

These GHG emissions come mostly from the energy sector representing two thirds of Human-related emissions. So, the energy sector is therefore an important area to reduce GHG emissions. The effort of reducing GHG emissions in a global scale started in the first Conference of the Parties in 1995 but no great results were reached since then. The emissions of GHG and the atmospheric concentration of these gases have still increased. Currently, the International Panel on Climate Change (IPCC) has determined that in the lack of fully compromise and urgent actions, Earth will have irreversible and extreme impacts. The main goal is to keep the temperature rise bellow 2ºC, relative to pre-industrial levels [1].

The International Energy Outlook 2016 (IEO2016) Reference case presented by U.S Energy Information Administration forecasts significant growth in worldwide energy demand until 2040, as demonstrated in Figure 1.1 that shows the world energy consumption, for the period of 1990-2040, in quadrillion Btu on OECD (Organisation for Economic Co-operation and Development) and non-OECD countries [2].

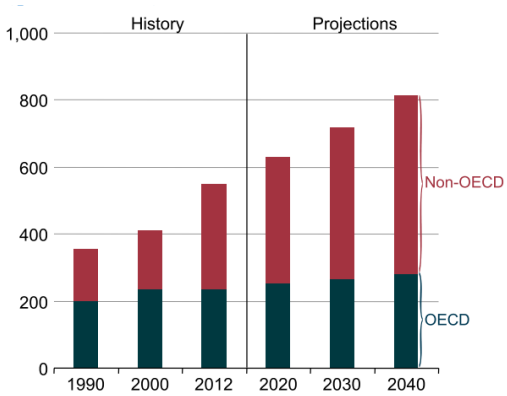


Figure 1.1 - World energy consumption from 1990 to 2040, in quadrillion Btu [2].

From 2012 to 2040, the total world consumption of marketed energy is forecasted to increase from 549 quadrillion Btu to 815 quadrillion Btu, which represents about 48% of increase. The global energy market is dominated by the combustion of fossil fuels and by the year of 2040 it is foreseen that it will still account for 78% of the energy production [2].

The combustion of fossil fuels emits carbon dioxide (CO_2), methane and some traces of nitrous oxides. Figure 1.2 shows the global GHG emissions by gas for the year 2010. CO_2 is the main GHG representing 65% of the gas emissions. Also, 11% of gas emissions are due to CO_2 release from forestry and other land use [3].

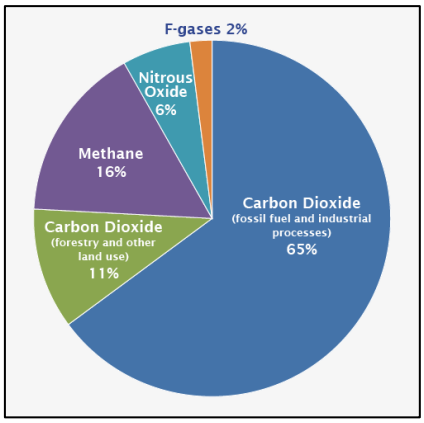


Figure 1.2 - Global GHG emissions by gas for the year 2010 (adapted from [3]).

The rapid increase in the atmospheric concentration of CO_2 has raised the spectre of severe climate change, so it is mandatory to reduce and prevent CO_2 emissions.

The CO_2 emissions from the use of fossil fuels like coal, liquid fuels and natural gas (NG) increased in the IEO2016 Reference case from 1990 to 2020. As shown in Figure 1.3, the forecast indicates that the emissions due to the consumption of fossil fuels will still increase with time.

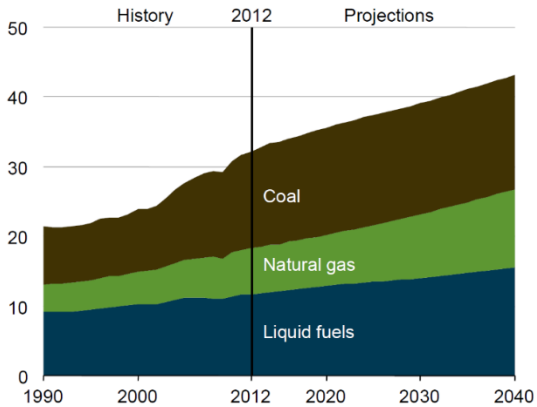


Figure 1.3 - World energy-related CO_2 emissions by fuel type from 1990 to 2040 (Billion metric tons).

The energy sector has become a primary agenda for efforts in stabilizing the climate system. Therefore, renewable energy (RE) systems are extremely important in providing energy services in a sustainable manner, decarbonizing the energy sector, and in reducing climate change to keep the temperature rise bellow 2ºC [4].

RE is any form of energy from solar, geophysical or biological sources that is replaced by natural processes at a rate that equals or exceeds its rate of use. This energy sources are obtained from flows of energy occurring in the natural environment [5]. There are numerous forms of RE such as wind energy, solar energy, geothermal heat, hydropower, tide and waves, ocean thermal energy and biomass [3].

Some country's policies have adjusted for the goal of decreasing emissions from fossil fuels and there are new policies to raise the share of RE around the world to mitigate climate change.

One of the problems with the majority of RES is the difficulty to synchronize the energy demand with the energy supply because they have an intermittent nature [6].

Another problem is that the current energy systems have almost isolated energy supply chains, namely for mobility, electricity, heating and cooling, reducing its potential for synergies [7]. Such a synergy is within the concept of smart energy system (SES) where the electricity, thermal and gas grids are interconnected to achieve an optimal solution for all the system. The concept is used to search for the least cost solutions while maximising RE penetration and synergies across the system. The final aim of the concept is to reach energy systems with 100% RES [8].

Renewable heating and cooling are vital to decarbonize the energy sector according to the EU's Energy Roadmap for 2050 [9]. The European Commission states also that is essential to assess and explore the synergies between heating, cooling and electricity [10].

A combined heat and power (CHP) system exploits the synergies between heat and power producing significant energy and CO_2 savings compared with isolated generation of heat and power. It is used in industry and in the services sector to save costs and ensure a stable and reliable heat and electricity supply. Combined cooling, heat and power plants (CCHP) should also be exploited to produce cooling from heat production in the summer. Many of these technologies can use RE, alternative fuels and waste heat. They can work in combination with thermal storage increasing its efficiency as heat production can be stored and used later [10].

Biomass, mainly in the form of wood, is the oldest form of energy used by humans through direct combustion, that is still used in many parts of the world [11].

Biomass conversion processes are considered carbon neutral. The biomass carbon reacts with oxygen in the air to form CO_2 which is released to the atmosphere. The amount of CO_2 generated is equal to the amount that was taken from the atmosphere during the life cycle of the biomass. All in all, there is no net addition of CO_2, this is known as carbon cycle [12].

There are several biomass conversion technologies, namely, thermo-chemical conversion processes (combustion, gasification, pyrolysis and liquefaction) and biological conversion processes (alcoholic fermentation and anaerobic digestion) [11].

Biomass gasification is one of the most promising thermal biomass conversion technologies. It can be used for production of power, heat and different fuels [13]. The gasification process releases heat that is used by the different phases of the process, the heat surplus can be exported. With the exceeding heat, power can be generated [14]. The biomass gasification is one of the key technologies to fulfil the goal of sustainable RE systems in the future because it can increase the needed flexibility in the system that is driven by intermittent RES. This is due to the flexibility that the system can offer regarding the production and short start-up time. Produced gas can be stored in the gas network and help balancing the system [13].

Since biomass conversion technologies and the synergies between heat, cooling and power can play a role towards a 100% RE system, it is important to explore the links between them as a SES. Hence, the present study is focused in the replacement of NG by synthetic natural gas (SNG) provided by the gasification of biomass (bio-SNG).

1.2. PREVIOUS STUDIES

In this section, a literature review is carried out. The literature review is divided in three main topics: 100% RE systems, where this approach to energy planning is explained and some related studies are presented; biomass gasification and upgrade studies, where current available technologies are reviewed; and finally, replacement of NG studies are presented, where the technical and financial feasibility of this replacement is studied.

1.2.1. TOWARDS 100% RE SYSTEMS

The design and modelling of 100% RE systems is well developed. For example, Aalborg University has several studies regarding SES and high penetration of RES. Models and methods are discussed as well as specific tools, like EnergyPLAN, to help the concretization of integrating all the grids and RES.
The studies presented next are more focused in CHP and district heating.
The design of 100% RE systems comprises three great changes: energy savings on the demand side, efficiency improvements in the energy production and the replacement of fossil fuels by RES. The aim of designing a 100% RE system is to integrate intermittent RES into the energy system and to include the transportation sector [15]. The methodology for analysing technologies in RE systems and for assessing the technical and socio-economic consequences, can be divided into three parts. The data and technology input phase, the phase for adjusting energy systems technically and insuring flexibility, and the main technological and socio-economic results. In addition, the fuel and CO_2 prices are essential to the analyses [6].
In Mathiesen et al. [8] and Lund et al. [15] a methodology was developed to take into account the key challenges for coherent integrated scenarios with 100% RE in 2050, using integrated hourly system analyses [8,15].
Mathiesen et al. [8] concluded that by analysing all sectors of the energy system, innovative solutions can be identified. The authors state that by applying a SES approach to the identification of suitable 100% RE systems design, it is possible to see how the system integration is a fuel efficient and cost effective option. In this study, the authors integrated the gas, electricity and heating grids in combination with storage options to create a SES for achieving the final scenario. Their hypothesis is that this approach is generally applicable and appropriate in designing 100% RE systems that are technically feasible, economically have similar cost to fossil fuel alternatives and can have sustainable consumption of bioenergy [8].
Connolly et al. [16] studied the steps towards a 100% RE system for Ireland. In 2007, Ireland supplied 96% of total energy demand with fossil fuels, however the authors state that there are enough local renewable resources to supply the energy demand. Firstly, the authors created a model of the Irish energy system identifying which tool was the most suitable for the research. EnergyPLAN was chosen because of the integration of all the grids. For this study, four 100% RE scenarios were carried out. The first based on biomass, the second based on hydrogen, the third based on maximising the use of renewable generated electricity. The fourth scenario is a combination of the previous ones. The authors

concluded that a 100% RE system is feasible and that there are numerous methods of achieving it. In addition, drastic reductions in energy required can be achieved by implementing the correct combinations of technologies [16].

Connolly et al. [7] also presented a scenario for a 100% RE system in Europe by the year of 2050. This is the first study that applies the SES concept at an EU level. This study uses a conservative assumption for the availability of bioenergy based on forecasts of EU bioenergy potential. The decarbonisation of the EU energy system should be a combined effort across Member States, rather than an individual effort. This work provides the key steps required for the transition to a SES. EnergyPLAN was used to model and analyse the EU energy system. The first steps to be implemented are the ones with a lot of political and scientific support, like, decommission of nuclear, heat savings and electric cars. Next is the individual heating and network heating. Finally, the renewable electrofuels are produced to be used in the transportation sector, then coal and oil are replaced by biomass and NG, and lastly the NG is replaced by renewable electrofuels. As the steps are carried out, the Primary Energy Supply (PES) is measured. The authors stated that to reach a 100% RE system there would be an increase of 12% in total annual costs, however it is estimated that such a transition can generate approximately 10 million of direct jobs resulting in an overall gain for the EU economy [7].

Østergaard [17] reviewed EnergyPLAN simulations studies and performance indicator applications in EnergyPLAN simulations. The number of articles of each topic are in parenthesis. EnergyPLAN was used to analyse several types of topics such as: integration of RES into the energy system (30), high-RES scenarios (15), general methodological issues within energy systems modelling and simulation (7), low-RES scenarios (6), transport (6), district heating (6), the role of energy savings and the systems impacts hereof (5), life-cycle assessment (3), grid stability (3), transmissions issues (3), biomass usage (2), desalination (2), waste as an energy resource (2), carbon capture and storage, photovoltaic, market structures, thermoelectric generators and CHP (1). This review showed that EnergyPLAN was used in a wide range of articles for system's modelling. Also, the author stated that most analyses are realized on a country or state level with the main focus of developing high-RES scenarios. Fewer articles focus on modelling and inclusion of other technologies in the energy system [17].

Lund et al. [18] described the role of district heating in future RE systems based on the case of Denmark. In Denmark, 46% of heat demand is met by district heating (DH), mainly CHP systems and the remaining is mostly heated by individual boilers. The authors used EnergyPLAN and proposed three scenarios where they increase the area of the DH to compare with the reference scenario. To achieve a 100% renewable scenario, bioenergy was proposed to replace fossil fuel demand. The authors concluded that a reduction in fuel demand and CO_2 emissions can be achieved in the present and in the future, by converting the individual heating areas to DH [18]. Similarly, Duquette et al. [19] used EnergyPLAN to evaluate the benefits of widespread combined heat and power based district energy networks in Ontario by increase the area of effect of the district energy network. The results show that a reduction in fossil fuel demand and CO_2 emissions was achieved [19].

Lund and Mathiesen [20] studied the integration of fluctuating RES with the sustainable use of biomass in CHP plants using EnergyPLAN. The authors consider that the large CHP plants in Denmark generate an unsustainable level of biomass consumption. Various CHP systems are considered in this study.

Combined cycle gas turbine, circulating fluidised bed and advanced pulverised fuel technologies. The authors concluded that combined cycle gas turbine CHP fired with gas from wood chips gasification is the most feasible technology in terms of total socioeconomic costs and biomass consumption [20].
Several studies regarding 100% RE systems were reviewed. They showed that by integrating the grids and exploring its synergies, such a system is possible to achieve. Also, CHP plants are very important in the challenge of a 100% RE system since they integrate heat and electricity production to reduce fuel consumption.

1.2.2. BIOMASS GASIFICATION AND UPGRADE

In this sub-section, gasification is briefly explained, several projects are presented as well as the problems that this technology faces. Also, gas cleaning projects and upgrading to NG quality are discussed.
There are two types of gasification processes, the direct and the indirect (also known as allothermal) gasification. In the direct gasification process, combustion takes place in the gasification reactor and air-blown is mostly used. This means that nitrogen will be present in the producer gas, which is not desirable for bio-SNG. Using oxygen or steam instead of air will lower the efficiency. In the indirect gasification, the combustion takes place outside the gasification reactor, the heat is then carried by heat carriers, commonly sand. The direct gasification methods are used over the world. The Finnish company ANDRITZ Carbona and the Danish company Pyroneer developed relevant technologies for the future of bio-SNG. The indirect gasification is best developed in Austria, Netherlands and Sweden. The Güssing plant, developed by the company Repotec in Austria and in Sweden and the MILENA-OLGA technology developed by the Energy research Centre of Netherlands are the most promising [21].
Production of bio-SNG from gasification of biomass is only possible with a methanation unit placed after the unit that produced syngas. Before methanation, gas cleaning is necessary to not damage the catalysts and other components [22].
Iskov and Rasmussen [21] reviewed projects and technologies for bio-SNG production. The Güssing gasifier plant is an indirect gasification system based on fluid bed technology and steam. It was primarily developed at Vienna University of Technology. It is called the FICFB-technology (Fast Internal Circulating Fluid Bed). The reactors consist of two fluid beds (dual fluid bed), one for gasification and one for combustion. Figure 1.4 shows the diagram of indirect gasification principle.

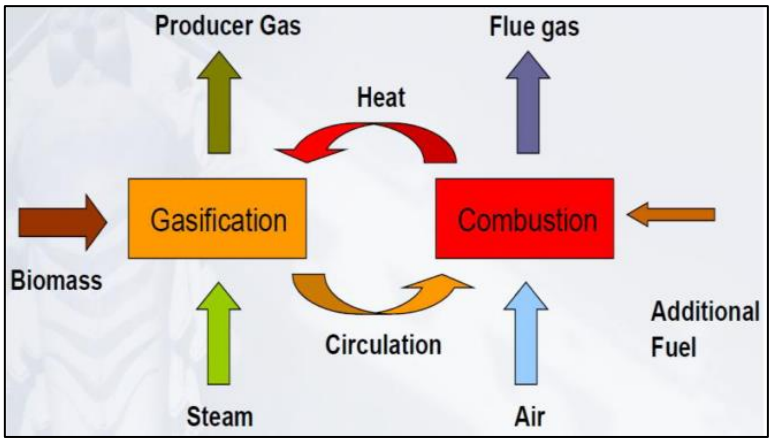


Figure 1.4 – Diagram of indirect gasification [21].

In the gasification reactor, steam is fed from the bottom and biomass from the side. The heat needed for the process is added in the form of hot particles like sand, dolomite, etc. The producer gas exits from the top of the gasifier. Sand and char particles are transported to the combustion reactor. In the combustion reactor, air is fed at the bottom and char particles from the gasification process burn in the fluid bed, heating the sand. Based on the lower heating value (LHV) of the biomass, this method can achieve an efficiency up to 70% from biomass to bio-SNG. In Güssing, Austria, an 8 MW gasifier plant is in operation connected to a 1 MW methanation unit. The gasification products are used in boilers, CHP, etc. Also, for demonstration purposes, a compressor unit was installed and NG vehicles were fuelled with bio-SNG [21].

The GOBIGAS project is located in Gothenburg, this project will use the Güssing technology to build a 20 MW bio-SNG facility. An 80 MW bio-SNG facility is later planned. This is the world's first large-scale commercial plant for generation of bio-SNG from biomass via gasification. This can be achieved by upgrading the syngas into NG quality for injection in the grid [21].

The first design of the MILENA gasifier was made in 1999. It is an indirect gasifier, meaning it has separate sections for gasification and combustion. Figure 1.5 shows a simplified scheme of the MILENA process. The gasification section consists in a riser, settling chamber and downcomer. The combustion section contains the bubbling fluidized bed combustor and the sand transport zone. Biomass is fed into the riser and a small amount of superheated steam is added from the bottom to enable bed material circulation. Hot bed material enters the riser from the combustor. The bed material heats the biomass to 850ºC. The biomass particles then degasify and era converted into gas, tar and char. The producer gas leaves the reactor from the top and is sent to the cooling and gas cleaning section. The combustor operates as a bubbling fluidized bed. The downcomer transports bed material and char from the gasification section into the combustor. Tar and dust return to the combustor. Then, they are burned with air to heat the bed material to 925ºC. Flue gas leaves the reactor to be cooled, de-dusted and emitted. No additional heat input is required because the necessary heat is produced by the combustion of the char, tar and dust. The hot producer gas then is cooled for tar condensation. The heat recovered is used to pre-heat combustion air. Tar and dust are removed from the gas in the OLGA cleaning section. Dust and tar return to the combustor [23]. Meijden et al. [23] designed and built a pilot plant to carry out

experiments under realistic commercial conditions. The technology has been tested on lab-scale and pilot scale and these tests have shown that the reliability and the availability of the technology increased sufficiently to start commercial projects.

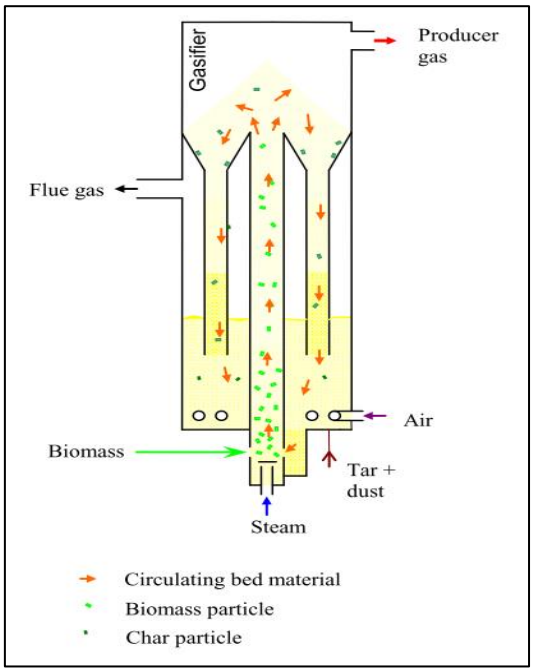


Figure 1.5 – MILENA gasifier scheme [23].

Drift et al. [14] compared both technologies described before, the Güssing gasifier and the MILENA-OLGA technology. Both are indirect gasification systems, the most suitable process because it produces a nitrogen-free gas. The authors concluded that the MILENA-OLGA technology can achieve an efficiency of 70% from biomass to bio-SNG, while the Güssing gasifier can only achieve an efficiency of 64% [14].

Regarding direct gasification, some examples are briefly explained next. ANDRITZ Carbona developed a direct gasifier in Skive, followed by an advanced tar reformer. Although this gasifier is not suitable for bio-SNG, such a tar reformer is relevant for a facility producing producer gas for SNG production. The facility has a bubbling/circulating fluid bed with dolomite as bed material [21].

Pyroneer gasifier technology uses a double circulating fluidized bed system giving relatively low temperatures in the system. Different types of biomass fuels can be used, making the process flexible. If steam and oxygen or just steam is used, the Pyroneer technology can produce syngas and then could be methanised for bio-SNG [21].

Boiler manufacturer Weiss developed the Viking gasifier in Handsund [21]. First, the biomass is dried, then pyrolyzed and then the coke residue is gasified in combination with cracking of tars. This system produces a highly pure gas to be used in gas engines. The drying and pyrolysis methods are of interest in combination with other gasification methods for bio-SNG production [21].

Heidenreich and Foscolo [24] developed a new gasifier named UNIQUE which integrates gasification, gas cleaning and conditioning in one reactor unit. By implementing all the systems in one reactor,

thermal losses, equipment and plant space are reduced. Catalytic filter elements for particle and tar removal are integrated into the fluidized bed. This allows the conversion of tar, elimination of trace elements and efficient abatement of the particulate, delivering high purity syngas. Also, the authors studied a polygeneration strategy approach, producing multiple energy products from biomass gasification to improve economic viability, sustainability, efficiency and flexibility. The authors concluded that the development and concretization of polygeneration strategies depend on national governmental energy policy. CO_2 incentives and tax supports are required to achieve an economically competitive production of biomass based fuels and power [24].

Gas Cleaning and Upgrade

There are different technologies for syngas cleaning: dust cleaning, tar conversion/separation, sulphur and chlorine removal, reforming and shift processes [22]. For dust cleaning, a high temperature filter is used to separate the gas from the particles by centrifugation [25]. For tar separation/cracking, tars can be removed by physical separation, where condensed tars are removed in a similar manner as particles, tars in the gas phase are absorbed by a solvent. Also, tars can be removed by catalytic of thermal cracking of tars [25]. Sulphur can be removed by adsorption on solids, that have to be renewed after being used [25]. The reforming and shift processes adjusts the ratio between hydrogen and carbon monoxide in a shift reactor by adding steam [25].

In the methanation unit, hydrogen, carbon monoxide and CO_2 in the syngas are converted to methane and water. Methanation normally takes place in a nickel based catalyst at a temperature of 250-450 ºC and is a exothermic process [22].

Haldor Topsoe's, a company specialized in catalysis, has developed the Topsoe's Recycle Methanation Process (TREMP) that can convert hydrogen and carbon monoxide in the ratio 3/1 into methane. The gasification products have to be conditioned before the process [22]. A combined shift and methanation reactor was developed at Paul Sherrer Institute, in Switzerland, and it was used at the Güssing gasification plant. It is based on fluid bed technology and operates at low temperatures. In the process, the CO_2 is separated after the methanation using common technology [22]. Another methanation process to produce SNG was developed at Zentrum für Sonnenenergie- und Wasserstoff-Forschung, Germany, consisting in one long tube containing catalyst material [22].

It is in the European Nordic countries like Denmark, Sweden, Netherlands, Finland and Austria that the gasification technology is better developed. The higher heat demand in those countries requires more fuel and the transition to a RE system is responsible for such development in the renewable fuels area to face the problem of reducing fossil fuels. The gasification technology has proven to be an available technology to face the problems of the transition to a 100% RE system.

1.2.3. REPLACEMENT OF NATURAL GAS

This section provides studies that determine the technical and financial feasibility of projects focused on the replacement of fossil fuels, specially NG, by biomass gasification for power and heat generation.

Asadullah [26] reviewed the barriers of commercial power generation using biomass gasification gas. The barriers from the collection of biomass to electricity generation are addressed, namely, biomass supply chain, pre-treatment of biomass, biomass gasification and its operating variables, gas cleaning and use of gas for power generation. One of the biggest challenges in biomass supply chain is the widely distribution that the biomass has across a country, so the delivery to the conversion facility implies costs. As for the pre-treatment of biomass, biomass drying, grinding and densification are the more concerning. The type of gasification is important, as well as the operating values like temperature, pressure, gasifying agent and air fuel ratio. For gas cleaning, there are several important aspects that were stated earlier like physical cleaning methods, thermal methods and catalytic methods. For power generation, some parameters must be assured for the use in a gas turbine and engine in terms of tar concentration. The author concluded that biomass conversion technologies suffers several problems that slow down the commercial exploration for power generation [26].

Groth and Scholtens [27] compared biomass and NG CHP projects in Denmark and Netherlands based in a cost-benefit analysis. The cost-benefit analysis is an approach to estimate the strengths and weaknesses of project alternatives. The projects are compared for the two similar countries. Spark ignition gas turbine CHP and single cycle mini gas turbine CHP technologies are compared. Emissions costs were evaluated, including methane emissions. 1 kg of methane emissions was considered equivalent to 25 kg of CO_2 and 1 kg of N_2O equals 298 kg of CO_2. The Net Present Value (NPV) was calculated for the NG CHP and compared with the NPV for the biomass CHP. Results show that the NPV for biomass CHP is much more positive in relation with NG system for both countries for the first technology and considering the emissions of methane. When excluding costs of methane emissions, the results show the contrary. Also, if the second technology is used, the methane emissions are reduced and biomass CHP is preferable relative to NG option only in Denmark. The authors conclude that the variation in fuel prices and emissions costs are what drives the difference between the two countries [27].

Iodice et al. [28] studied the technical and financial viability of a new modern trigeneration plant in a new Naples district. Two alternatives were compared, both with internal combustion engines, one fuelled by NG and the second one with renewable vegetable oils. Firstly, the energy demand was assessed. Then, a performance analysis of the two alternatives was addressed. Assumptions and costs for both alternatives were discussed. NPV, payback period and return on investment were calculated for both scenarios as well as a sensitivity analysis for the payback period. The environmental impact assessment was just conducted for the most technically convenient and profitable alternative. The authors concluded that the option with vegetable oil is the most suitable, with a payback period of 4.6 years. The presence of this new plant could increase the pollutant concentration by less than 2% [28].

The studies have shown that the replacement of NG by bioenergy alternatives is possible. CO_2 and other GHG cost emissions can be a key factor for the financial feasibility of the projects. Also, green funds and incentives should be assessed for this kind of projects.

1.3. OBJECTIVES

To decrease GHG emissions and to understand the path towards a 100% RE in the future, the objective of the present study is focused on the technoeconomic feasibility and environmental impact of replacing NG, that is fed to a CCHP plant, by biomass and its conversion products. For this, an analysis is carried out using several scenarios according to the percentage of biomass used to feed the CCHP plant in the total fuel used. The analysis is performed for a life time of 25 years and considers the fuel demand of the plant, the investment costs regarding the transition to biomass, the biomass and NG costs, the importation and exportation from the gas grid, the remunerable exportation of electricity, the CO_2 emissions' costs and the capacity and flexibility of the gasification equipment. The specific objectives are to evaluate the financial feasibility of this type of project in a CCHP fired by NG and to see which is the best scenario considering both the economic and the environmental impact. Some questions will be answered with this work as:

- Is this kind of projects technically and financially viable in Portugal?
- Which is the economic and environmental best scenario regarding the share of bioenergy in the fuel demand on an already constructed CCHP?

1.4. PRESENT CONTRIBUTION

The operation of the CCHP is modelled using Energy Plan and a financial analysis is carried out, in order to evaluate the economic and environmental impact of replacing the NG used in the CCHP by bio-SNG coming from the gasification of biomass.

Firstly, an analysis is carried out on the current operation of the CCHP (Baseline scenario). Then, the analysis is made for two cases, one where all the NG of the CCHP is replaced by bio-SNG produced from the gasification of woodchips (Case 1) and other with the same gasification technology but where a woodchip fired biomass boiler is used to replace the auxiliary NG boiler on the peak loads of the heat demand (Case 2). For each case, different scenarios are accounted for the bio-SNG fractions considered: 25%, 50%, 75% and 100%. For each scenario, the remaining fraction is covered by NG.

The project financial feasibility is estimated based in a discounted cash flow analysis that includes the costs and revenues along the project lifetime that arise from the new implemented technologies. To measure the project financial feasibility, two indicators are considered, the NPV and the Payback (PB) period. Woodchips with a LHV of 17,5 MJ kg^{-1} and a gasification efficiency process of 70% are considered. All the results are based on the difference with the reference scenario (Baseline). The results for the different scenarios are compared along the study.

1.5. THESIS OUTLINE

The rest of this thesis is divided into four chapters. Chapter 2 presents the case study analysed, the Climaespaço trigeneration system, as well as a detailed description of the scenarios proposed. Chapter 3 describes the methods used to model the system and to carry out the technical and financial analysis. Chapter 4 presents and discusses the results of the scenarios. Finally, Chapter 5 summarizes the main conclusions of the present work and provides some suggestions for future research, respectively.

2. CASE STUDY

In 1998, Portugal organized the 1998 Lisbon World Exposition (Expo'98), where the theme was about the seas and oceans to commemorate the 500th year of Portuguese discoveries. The place chosen for the event was the east limit part of Lisbon, which has 330 ha and was degraded at the time. Beyond the exposition organization, the idea was to revitalize the region with the building of a new district. Keeping in mind environmental and energy issues, a heat and cooling urban grid was implemented to support the exposition and the new district consumption needs. A consortium won the license to build a CCHP plant and Climaespaço was born. Nowadays, the grid is composed by four tubes with more than 21 km of extension and provides thousands of clients. There are different types of clients: 50 buildings from the tertiary sector with a subscribed power of 36 MW of cooling and 20 MW of heat, 20 equipment buildings with a subscribed power of 20 MW of cooling and 17 MW of heat and about 4,000 clients from the residential sector with a subscribed power of 23 MW of cooling and 44 MW of heat. The buildings from the tertiary sector include a shopping mall, an oceanarium, a hospital, a casino, some large facilities for the organization of events, several offices and hotels [29].

Climaespaço is composed by the trigeneration plant (CCHP), where NG is transformed in hot and cold water and electricity and the distribution grid, where the cooled and heated water is provided to the substations located in the clients' buildings.

2.1. TRIGENERATION PLANT

The plant is composed by a TUMA Turbomach gas turbine and an ABB alternator with 4,7 MWe of nominal power. The heat recovery boiler is installed downstream of the turbine and is provided with an afterburning that uses the exhaust gases, beyond NG, to increase the thermal energy. The vapor produced is used in two absorption chillers working with lithium bromide to produce cooling and in two shells & tubes heat exchangers and one plate heat exchanger to produce hot water. There are four compression chillers that produce cooling from electricity and an auxiliary NG boiler with 15 MW of heat power to cover the peaks and the periods when the gas turbine is in maintenance (backup).

The water is heated to 100ºC in three heat exchangers by using the vapor of the heat recovery system of the turbine, and it is supplied to the grid, returning from the grid at 65ºC. The total capacity of the heat exchangers is 33 MW of thermal power.

Each absorption chiller has 4,8 MW of cooling power and the four compression chillers have a total of 24,2 MW of cooling power. The plant has a cold-water tank with a capacity of 15,000 m^3, the cooled water produced in the chillers is pumped to the reservoir at a temperature of 4ºC, temperature at which the water is provided to the grid. This water returns from the grid to the tank at a temperature of 12ºC, being supplied to the chillers again. The cold water is preferentially produced by night and stored in the tank to be consumed during the day [29].

The distribution grid has four tubes, two for the roundtrip of the hot water and other two for the roundtrip of the cold water. These tubes are constructed in underground facilities (technical galleries) for easy access [29].

The energy is transferred from the Climaespaço's grid and the clients' grid in substations that are located in the clients' buildings and are equipped with plate heat exchangers. There are usually two or three heat exchangers in each substation [29].

Figure 2.1 presents an overview of the current Climaespaço system layout.

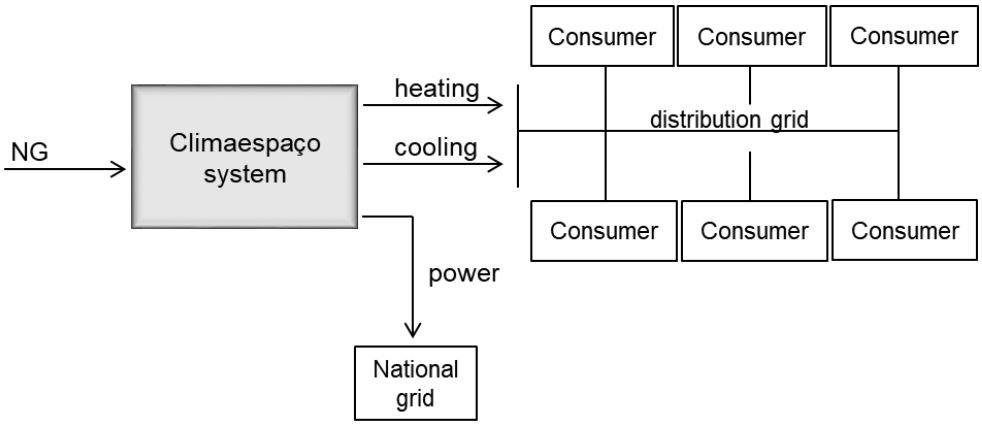


Figure 2.1 – Overview of the current Climaespaço system layout.

2.2. ENERGY PRODUCTION AND DEMAND

The daily energy consumption and production of the trigeneration plant for 2012 were provided by Climaespaço. Table 2.1 shows the annual sums of the data provided. In 2012, the trigeneration plant produced 61.03 GWh of heat, 75.99 GWh of cooling and 38.44 GWh of electricity using 143.71 GWh of NG.

Type of energy		Annual values (GWh)
Heat	**Total heat production**	**61.03**
	Heat produced by the CHP equipment (with afterburning)	55.76
	Heat produced by the auxiliary boiler	5.27
	Total heat consumption	**61.03**
	Heat provided to the grid	54.36
	Heat consumption in the absorption chillers	6.68
Cooling	**Total cooling produced**	**75.99**
	Cooling produced by the compression chillers	64.84
	Cooling produced by the absorption chillers	11.16
Electricity	**Total electricity production**	**38.44**
	Total electricity consumption in the plant	**22.03**
	Electricity consumption in the compression chillers	12.28
	Remaining electricity consumption in the plant	9.74
Fuel (NG)	**Total fuel consumption**	**143.71**
	CHP (with afterburning) fuel consumption	138.16
	Auxiliary boiler fuel consumption	5.55

Table 2.1 – Annual values of 2012 provided by Climaespaço.

To model this system, there is the need to have hourly data of energy production, and not just daily data. Hence, Climaespaço provided actual hourly data regarding the heat and cooling demand for a typical day in summer and winter. Figure 2.2 shows the customer's heat and cooling demand for one day in the summer and another day in the winter.

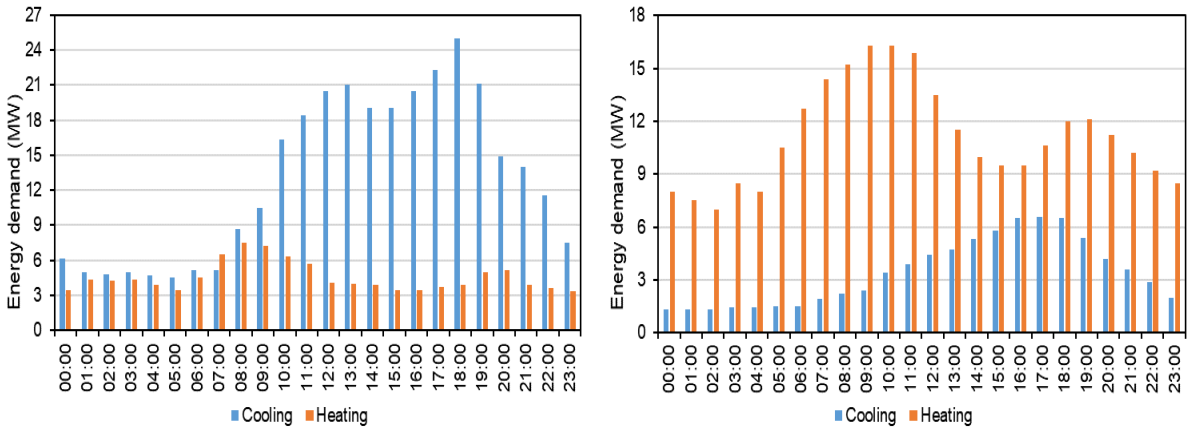


Figure 2.2 – Load diagram of heat and cooling demand of one day in the summer (left) and one day in the winter (right).

Since the cooling production does not match the demand of the consumers, due to the cold water tank, the hourly data provided was adjusted based on information given by Climaespaço regarding the operation of the plant:

- The cooling water is produced by the chillers mostly during the night (from 10 pm to 8 am) and stored in the tank. The stored water is provided to the consumers during the day. With this in mind, to adjust the data, the ten higher values of cooling were selected and its average value was put during the night production. The hourly values were then manually adjusted with an increase production until to reach the peak time. The relative distributions are presented in Figure 2.3 for one summer and winter day.
- The hourly variation within one day of the heat demand is considered to be equal to the production.

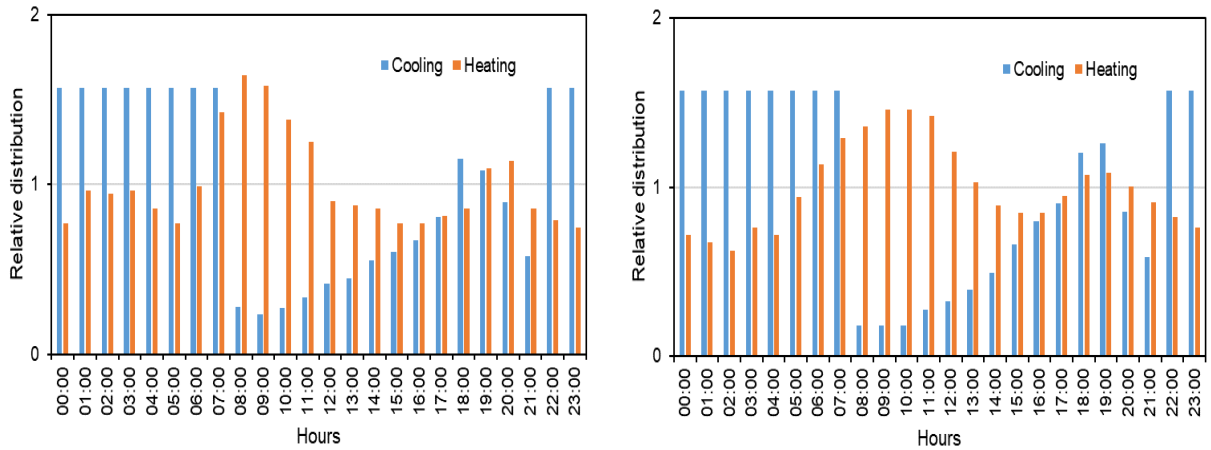


Figure 2.3 – Relative distribution of heat and cooling demand of a typical summer (left) and winter (right) day.

These hourly values were then merged with the daily data provided from Climaespaço for 2012.

As the system was modelled in the EnergyPlan the inputs need to be in line with the requirements of the tool. Regarding the energy demand inputs, for the EnergyPlan are relative hourly distributions, i.e. the values are relative to the total annual value. Hence, to model the system, relative hourly distribution for heating and cooling productions were carried out.

To merge the daily data with the hourly data, and to obtain the relative hourly distributions, both relative distributions were multiplied. To estimate the distributions, each hourly value of the year is divided by the annual average. To obtain the hourly values, the daily values are divided by 24 hours. The hourly values were then multiplied by the actual hourly distribution.

The winter time is considered from 1st of January until 30th of April and from 1st of October until 31th of December, the summer time is considered from 1st of May until 30th of September. So, the daily data for winter and for summer were merged in the specified days. The result was a total of 8784 relative values, one for each hour of the year, for both heat and cooling production, simulating, in this way, a year of operation of the plant. Figure 2.4 shows results of the estimation of the heat and cooling production throughout the year.

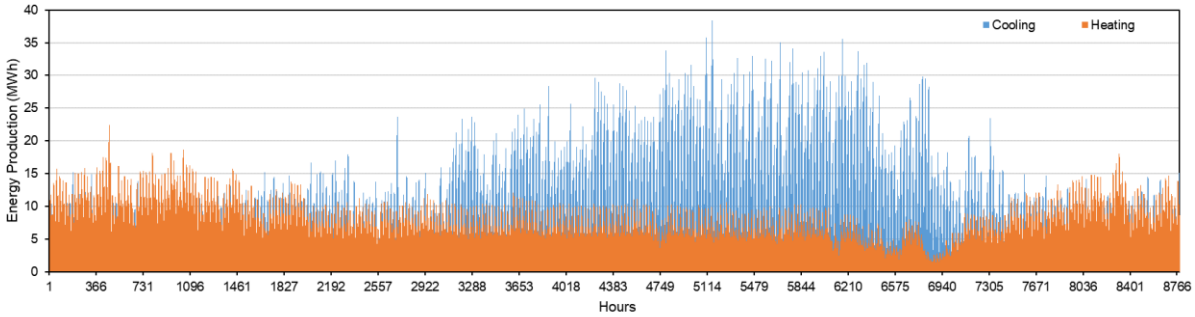


Figure 2.4 – Hourly heating and cooling production during 2012.

As expected in a region with this climate, the heat production reduces significantly in the summer and the cooling production increases for the same period.

Since there is no hourly data for electricity consumption, the daily values provided for 2012 were divided by 24 hours. The result is a distribution with the same values for all the hours of each day. This was carried out in order to have 8784 values, one for each hour of the year. Figure 2.5 shows the plant's electricity consumption along the year for each day. It can be seen that the electricity consumption is higher in the summer.

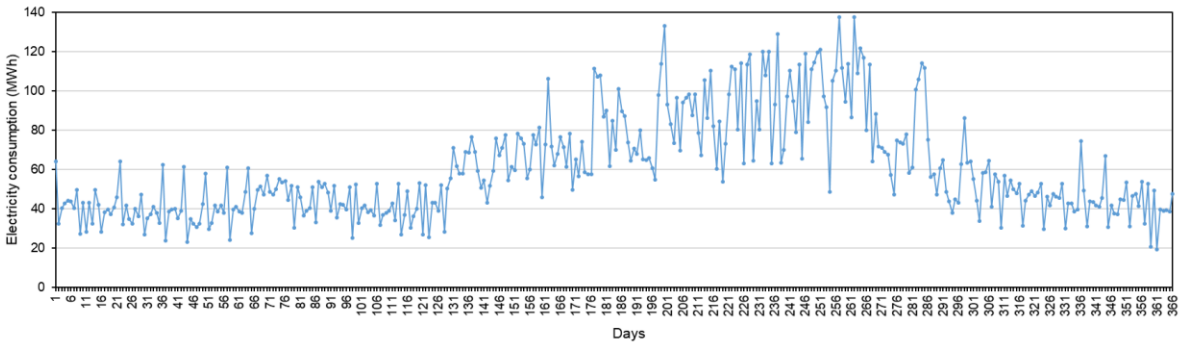


Figure 2.5 – Plant daily electricity consumption during 2012.

Table 2.2 summarizes the inputs for the baseline scenario provided in the data from 2012. The coefficient of performance (COP) for the absorption and compression chillers are calculated based on Eq.1. The cooling production (CP) is the specific production for each type of chiller and the energy input (EI) is either the electricity or the heat used for the compression and absorption chillers, respectively. Also, the CHP power efficiency (CHP PE) and CHP thermal efficiency are calculated based on Eq.2 and Eq.3, respectively. The CHP power efficiency is calculated by dividing the electricity production (EP) of the gas turbine by the turbine fuel consumption (TFC). The CHP thermal efficiency (CHP TE) is calculated dividing the total heat produced in the turbine (THP) and afterburning (ABHP) by their fuel consumption (TFC and ABFC). The values used are the total annual values provided by Climaespaço for 2012. The estimation of the CHP thermal capacity is explained in detail in section 3.1.1.

$$COP = \frac{CP}{EI} \tag{1}$$

$$CHP\ PE = \frac{EP}{TFC} \tag{2}$$

$$CHP\ TE = \frac{THP + ABHP}{TFC + ABFC} \tag{3}$$

Inputs	Value
Electricity demand (excluding for cooling)	9.74 GWh
Heat production (excluding for cooling)	54.36 GWh
Electricity demand for cooling	12.28 GWh
COP compression chillers	5.28
Heat demand for cooling	11.16 GWh
COP absorption chillers	1.67
Auxiliary boiler thermal capacity	15 MW
Auxiliary boiler thermal efficiency	0.95
CHP power capacity	5 MW
CHP power efficiency	0.29
CHP thermal capacity (estimated value)	8621 kW
CHP thermal efficiency	0.40

Table 2.2 – Inputs for EnergyPLAN based on the data from 2012.

2.3. SCENARIOS PROPOSED

To evaluate the potential of replacing the NG by gasified biomass, two cases were assessed. In the first case, it is considered the substitution of the NG consumed in an operation year by bio-SNG. Several scenarios are analysed, namely a biomass weight of 25%, 50%, 75% and 100% in the total fuel demand. For the case 2, the same principle is applied, apart from the biomass boiler addition that is set to replace the production of the existent NG auxiliary boiler. The percentage of fuel used in the new boiler is equal to the old one, which is 4% of the total fuel consumption. Although the NG boiler is replaced, it still makes part of the system for potential backups, to not compromise the heat and cooling delivery to the consumers when any problem occurs with the system. Figure 2.6 shows the layout of the proposed system. Table 2.3 summarizes all scenarios considered in this analysis and details their differences.

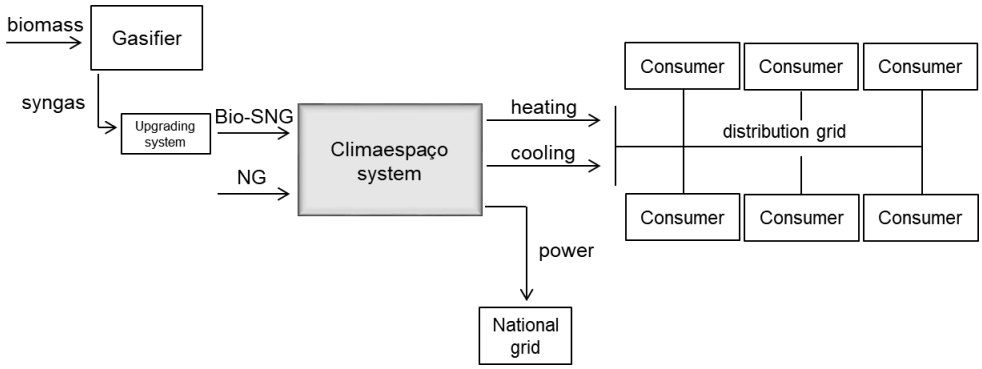


Figure 2.6 – Layout of the proposed system.

Case	Scenario	% of bio-SNG	% of NG	% of direct biomass combustion	Peak heat demand coverage
Case 1	25%Bio1	25%	75%	-	Auxiliary NG boiler
	50%Bio1	50%	50%	-	
	75%Bio1	75%	25%	-	
	100%Bio1	100%	-	-	
Case 2	25%Bio2	21%	75%	4%	Auxiliary biomass boiler
	50%Bio2	46%	50%	4%	
	75%Bio2	71%	25%	4%	
	100%Bio2	96%	-	4%	

Table 2.3 – Scenarios considered.

The biomass considered in the project is woodchips from pine with a LHV of 17.5 kJ/kg [30], a density of 253 kg/m^3 [31] and a moisture content of 30% [30,31].

Economic Data

Table 2.4 shows the investment costs, operation and maintenance (O&M) costs and lifetime of the equipment acquired. O&M costs are yearly costs and are presented as a percentage of the investment cost.

Equipment	Investment cost (M€/MW)	O&M (% of investment)	Lifetime (years)
Gasifier	0.4	5.3	25
Upgrading System	0.3	15.79	15
Auxiliary biomass Boiler	0.075	1.47	20

Table 2.4 – Costs and lifetime of the equipment [32].

In this study, a period of 25 years is considered for the project life time, being necessary to acquire new equipment during this time, namely, a new upgrading system and a new auxiliary biomass boiler. The gasification machines' residual value is considered in the revenues at the end of lifetime. This value corresponds to 10% of the investment cost [33]. Since no data was found for the biomass boiler residual value, 10% of investment cost is considered also. In the end of the project lifetime, 25 years, the upgrade and boiler systems are not in the end of its lifetime. A straight depreciation is applied to evaluate the economic value of these equipment at the lifetime end of the project. Their economic value is then added to the cash flow of the year 25th.

The NG price in 2016 for the CCHP considered was provided by Climaespaço and it varies between 7.1 €/GJ and 8.3 €/GJ (LHV based) [34]. The average value of 7.7 €/GJ was chosen.

The biomass price was provided by several producers in Portugal, namely, Sopromad Lda, Alberto & Alves Indústria de Embalagens do Carregado and Ecotoro Energia with an average price of 15 €/m^3 [35]. Considering the density of the biomass, its LHV and its unit price, the price per unit of energy is 3,388 €/GJ.

Revenues from exportation of electricity to the grid are considered since with the use of at least 50% of renewable fuel as primary energy, the CCHP is considered to be renewable as can be seen in point number 3 of the 5th article from chapter 2 of the decree law 23/2010 of 25th of March [36], and therefore the revenue from the selling of electricity increases. The reference selling price both for cogeneration and renewable cogeneration are taken from ERSE – Entidade Reguladora dos Serviços Energéticos [37], which is the entity that rules the energy services in Portugal. These values are 87,3 €/MWh and 94,67 €/MWh, respectively. Both prices are averages for the year 2016. The costs for the importation of electricity, i.e. for buying electricity from the national grid, are not considered.

3. METHODS

In the present study, different scenarios for the increase of biomass share in an already working CCHP fired by NG are analysed. The system is modelled using EnergyPLAN, a software that simulates the operation of one year of energy systems, where all the grids (heating, electricity and gas) are integrated. The NPV and PB period are calculated based on the discounted cash flow.

3.1. TECHNICAL ANALYSIS

Different tools used to analyse the integration of RES were reviewed by Connolly et al. [38]. EnergyPlan has been developed since 1999, at Aalborg University, in Denmark and it is a software that can be downloaded for free. The main focus of the program is to assist the design of energy planning strategies by simulating the operation of the entire energy system.

EnergyPLAN is a deterministic input/output tool and the main inputs are the energy demand, RES, power capacities, costs, some technical regulation strategies for the importation/exportation of electricity, among others. The outputs are energy balances and annual productions, fuel consumption, CO_2 emissions and imported/exported electricity [39].

The program simulates the operation of the energy system during one year and it is an hourly based time-step tool. Therefore, it can analyse the influence of weekly and seasonal differences in electricity and heat demands. It has different regulation strategies, such as balancing heat and/or electricity demands or either a market economic simulation.

EnergyPLAN uses hourly analyses for all the SES, namely, the district heating and cooling, electricity and gas grids and infrastructures. It is based on analytical programming so the calculations are direct and the model is fast when performing the calculations, the simulation of one year requires only few seconds for normal computers [39].

The layout of the EnergyPLAN is presented in Figure 3.1. This figure shows the diagram of the grid structure in the program. As can be seen, all the grids are interconnected, comprising the equipment/technologies and the storages. The flow of the diagram goes from the left to the right, from the primary energy sources (left) to the heat, cooling, electricity and transport demand (right).

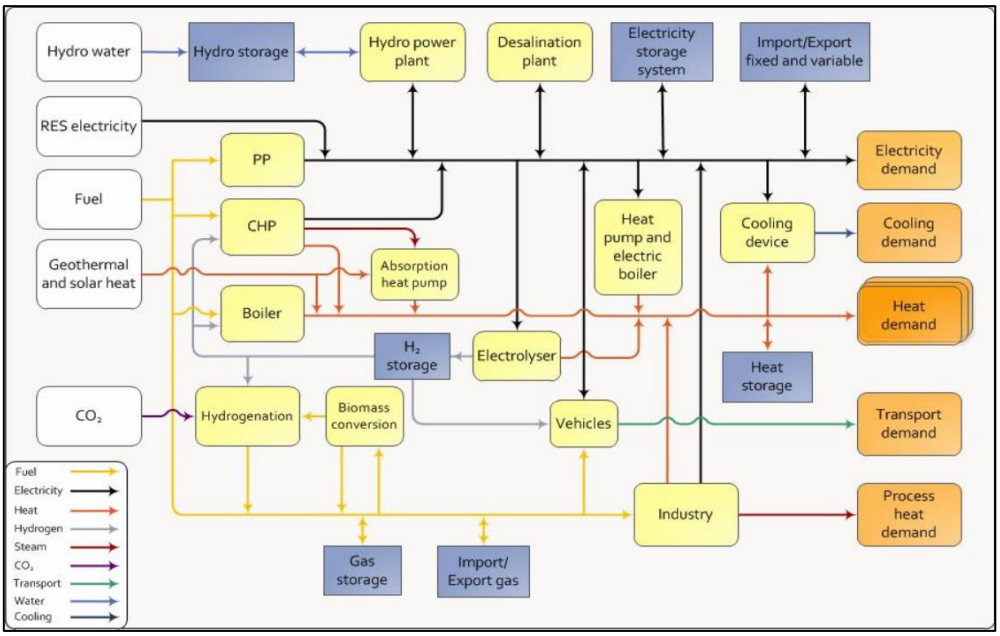


Figure 3.1 - EnergyPLAN version 12.4 layout [40].

The main modules used in this study are the electricity, heat and cooling demand modules, as well as the heat and electricity supply and gasification plant modules.

Figure 3.2 shows the electricity demand module, where the annual electricity demand and its distribution are used. The electricity for cooling is completed in the cooling tab and then is subtracted in the total electricity demand. So, the electricity demand distribution is for the electricity demand excluding electricity for cooling.

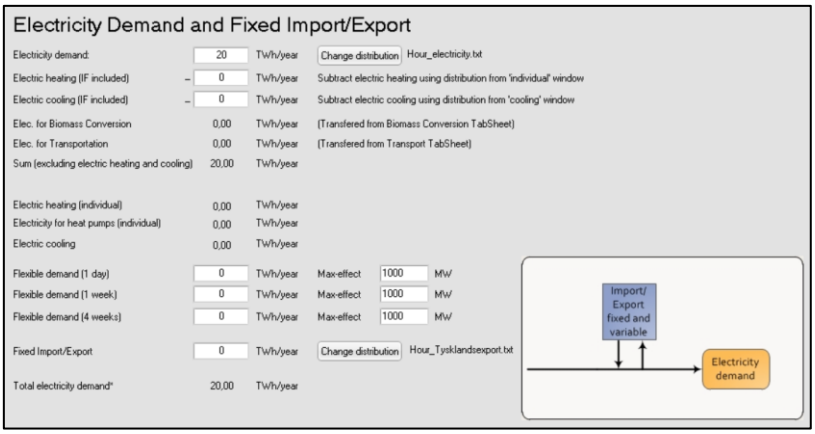


Figure 3.2 – Electricity demand module.

Figure 3.3 shows the heat demand module specific section of the district heating. EnergyPLAN considers three groups for district heating. The first does not have a CHP system, just boilers and other forms of heat supply. The second has small CHP plants, which cannot produce electricity without a heat load. The last one has large CHP plants that does not need to produce heat to produce electricity, they can waste heat and just produce electricity [41]. Only group 2 is selected, because the CHP studied is

decentralized, small and has the heat and electricity production coupled. Also, the heat distribution is completed here.

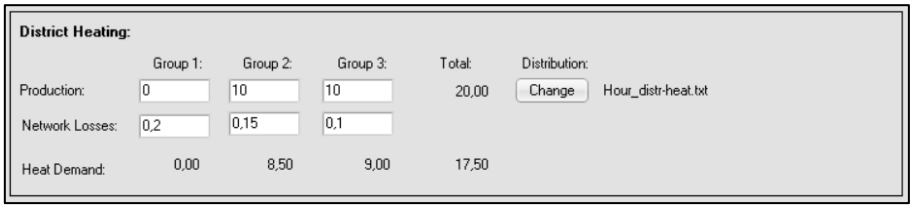


Figure 3.3 – Heat demand module.

In the cooling demand module, the cooling from electricity and the district heating for cooling (group 2) demands are completed. The cooling distribution is common for all the cooling demand. Also, the COP are completed for both demands. Figure 3.4 illustrates the cooling demand module input.

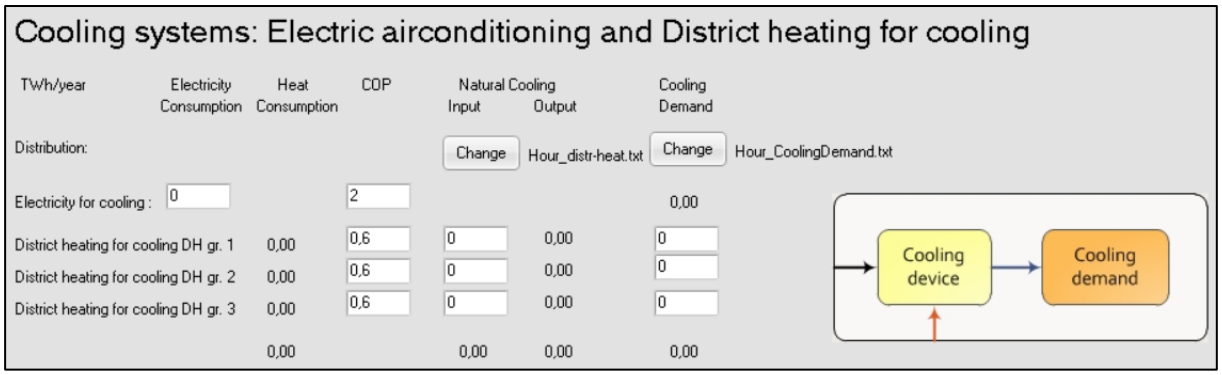
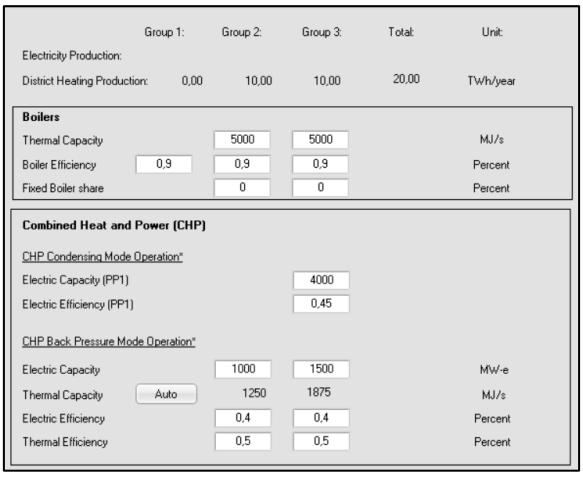


Figure 3.4 – Cooling demand module.

After the demands are defined, the supply side of the energy system is designed. The capacities and efficiencies of the equipment are completed. Figure 3.5 illustrates the heat and electricity supply module, where the group 2 is used because of the CHP type. The boiler and CHP efficiencies and capacities are used.



	Group 1:	Group 2:	Group 3:	Total:	Unit:
Electricity Production:					
District Heating Production:	0,00	10,00	10,00	20,00	TWh/year
Boilers					
Thermal Capacity		5000	5000		MJ/s
Boiler Efficiency	0,9	0,9	0,9		Percent
Fixed Boiler share		0	0		Percent
Combined Heat and Power (CHP)					
CHP Condensing Mode Operation*					
Electric Capacity (PP1)			4000		
Electric Efficiency (PP1)			0,45		
CHP Back Pressure Mode Operation*					
Electric Capacity		1000	1500		MW-e
Thermal Capacity	Auto	1250	1875		MJ/s
Electric Efficiency		0,4	0,4		Percent
Thermal Efficiency		0,5	0,5		Percent

Figure 3.5 – Heat and electricity supply module.

Finally, in the gasification module, the biomass input, the electricity share, the coldgas efficiency, the maximum capacity and the upgrade efficiency are used for this study. The gas produced in this module is used to replace the NG used in the system. Figure 3.6 shows the gasification plant module.

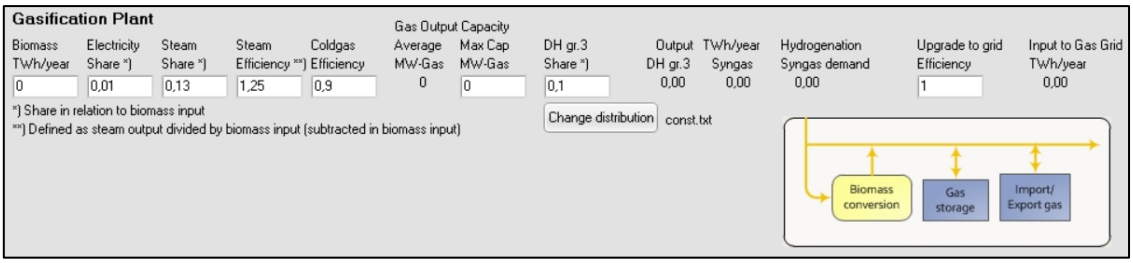


Figure 3.6 – Gasification module.

3.1.1 BASELINE SCENARIO

Firstly, the baseline scenario, i.e. the operation of the system as it is today and exposed in the Case Study Chapter, is modelled based on the data provided.

To calibrate the system, the thermal capacity of the CHP was iteratively chosen until the total yearly heat production in CHP (with afterburning) and boiler matched the data from 2012. Since EnergyPLAN does not consider the afterburning, there was the need to overestimate the thermal power capacity of the CHP equipment. In EnergyPLAN, the CHP electricity production capacity is fixed and the model is producing at maximum electricity load just when it is producing at maximum heat load, which is a limitation. In this way, increasing thermal capacity to match the heat demand would lower electricity production because the model is thermally overpowered and only uses the maximum heat capacity in the peaks, operating less time at maximum power capacity, resulting in lower electricity production on the model.

Another limitation in EnergyPLAN is in the cooling grid. There are two distribution inputs, one for natural cooling and other for cooling demand. The last one comprises both cooling from heat and from

electricity. This results in a coupled cooling production based on the proportion of production from each source, which does not give freedom to choose when to produce cooling from heat. The cooling produced from heat in Climaespaço plant is mainly produced in the summer. In the model simulation, the cooling production from heat occurs all year-round. Hence, producing cooling from heat in the winter, increases the heat demand that is already superior compared to other periods, resulting also in an overestimation of the thermal capacity.

It was decided to calibrate the model based on the heat demand, which resulted in an error in the estimation of the electricity production.

The model is simulated with strategy 1 from EnergyPLAN where the heat demand is met, i.e. the heat demand is the priority of the model, as the principal focus of the plant is to provide heat (and cooling but not from the cogeneration system). In this strategy, the units that provide heat have different priorities. Since in this case study, there are only CHP and boiler systems, the CHP has priority over the boiler when providing heat. Therefore, the boiler starts to work in the heat peak loads, when the CHP system does not have sufficient capacity to match the demand [40].

3.1.2 CASE 1

After modelling the reference scenario, the total fuel demand (NG) is obtained. The bio-SNG demand is calculated multiplying the total fuel demand by the biomass share, for each scenario. The total biomass needed is calculated dividing the bio-SNG demand by the efficiency of the total gasification process. This value is an input of EnergyPLAN. Table 3.1 shows the input values of biomass.

Scenarios	25%Bio1	50%Bio1	75%Bio1	100%Bio1
Biomass for gasification input (GWh)	51.33	102.65	153.97	205.30

Table 3.1 – Biomass input for gasification in the case 1.

An efficiency of 70% is chosen for the gasification process based on the optimum operation of Milena-Olga gasification process. The value refers to the conversion process from biomass to bio-SNG in terms of chemical energy content [42]. Figure 3.7 shows the flow diagram of the process. The first efficiency is the coldgas efficiency with an efficiency of 80% [42], which is the producer gas efficiency. For the upgrading system, the efficiency is 87.5% [42] and the total efficiency is then 70% from biomass to bio-SNG.

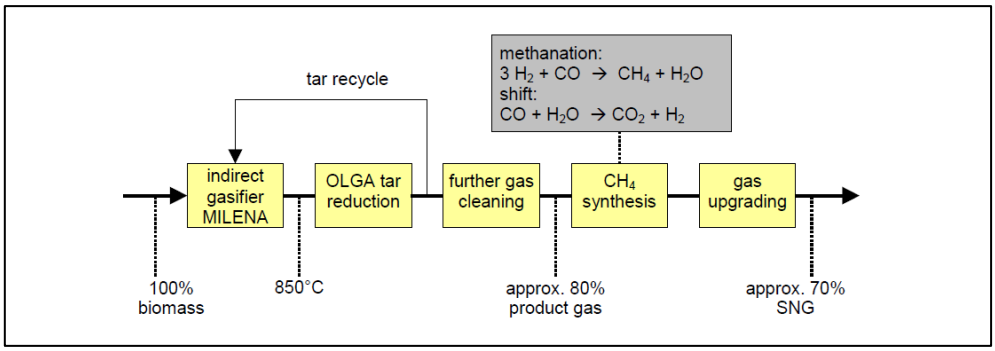


Figure 3.7 – Milena-Olga gasification process (adapted from [42]).

Other inputs in the gasification plant section are the electricity share, coldgas efficiency, upgrade to gas grid efficiency and the maximum capacity of the gasifier. The electricity share is the electricity demand that the gasification plant needs in relation with the biomass input and the value chosen was 1.5% based on [43]. For the coldgas efficiency, the value chosen was 80% and for upgrading efficiency was 87.5%. The maximum capacity of the gasifier is the input responsible for the flexibility of the gasifier. The value for the maximum capacity was chosen iteratively until no exportation of bio-SNG nor excess of NG importation occurs.

3.1.3 CASE 2

The objective of adding a biomass boiler is to reduce gasification infrastructure and biomass demand since the boiler efficiency is higher. The biomass boiler replaces the auxiliary NG boiler in the model.
The capacity of the new boiler, fired with biomass, is chosen based on the capacity of the existing NG boiler, which is, 15 MW_{th}. An efficiency of 82.7% is chosen from the boiler's catalogue [44], with the boiler respecting the specifications of the CCHP providing 20 t/h of vapour at a temperature of 194ºC and at a pressure of 1,25MPa.
In this case, the bio-SNG needed is estimated by subtracting the NG demand (according to its share in each scenario) and the boiler fuel demand to the total fuel demand. The gasification inputs in the model are the same as the case 1 except for the total biomass used and for the maximum gasifier capacity. In relation with the maximum capacity, the same approach was conducted as in case 1. Table 3.2 shows the input values of biomass for gasification.

Scenarios	25%Bio2	50%Bio2	75%Bio2	100%Bio2
Biomass for gasification input (GWh)	43.37	94.70	146.02	197.35

Table 3.2 – Biomass input for gasification in the case 2.

3.2. FINANCIAL ANALYSIS

In order to evaluate the financial feasibility of the project, a discounted cash flow analysis is made considering the difference of costs and revenues from the new plant concept and the reference scenario. The discount rate is assumed 6% for all the calculations [45]. The discounted cash flow (DCF) is a method for evaluating the feasibility of an investment opportunity; it uses the future cash flows (CF) projections and discounts them to the present value estimate. The sum of all future cash flows is the net present value (NPV). In the present study, since all the calculations are done in comparison with the reference scenario, when NPV reaches zero, the project starts to be attractive in relation with the reference scenario. The number of years needed to reach that value (the payback period) is also relevant. The NPV also depends on the discount rate (r) and is calculated using Eq. 4.

$$NPV = \sum_{t=0}^{N} \frac{CFt}{(1+r)^t} \tag{4}$$

The CF for each year is calculated by the difference of the revenues and the costs in each year as shown in Eq. 5.

$$CF_t = Revenues_t - Costs_t \tag{5}$$

To do a cost analysis, with the intention to compare the investment and the yearly costs from biomass purchase and O&M, an annualization of the investment was made based on capital recovery factor (CRF). In order to annualize the investment, it was multiplied by CRF which converts a present value into an equal flow of annual payments over a specified time (t), at a specified discount rate (r). The CRF formula is exposed in Eq. 6.

$$CRF = \frac{r(1+r)^t}{(1+r)^t - 1} \tag{6}$$

The costs include the annualized investment, the O&M costs and the biomass costs.

3.2.1 CO_2 EMISSIONS' COST

CO_2 emissions from energy provided by biomass are considered to be zero due to the biomass cycle, so all the emissions are only coming from the burning of NG. The emissions due to the transportation of the biomass from the collection site to the plant are not considered since this study is focused on the operation of the plant itself and the life cycle of the biomass used is not considered.

The CO_2 emission factor of the NG is presented in [46] and has the value of 56.1 $kgCO_2/GJ$.

CO_2 emission allowances in EU Emissions Trade System (EU ETS) market are also assessed. The emissions avoided by using biomass are considered to be traded in the EU ETS market being reverted

in revenues. The price used is taken from [47] and it is the mean value for the year of 2016, which is 5.35 €/ton. Nowadays the price is extremely low compared to the prices of when the market was created.

3.2.2 REVENUES

In this study, the revenues considered were the avoided costs, from the CO_2 emissions that are not emitted and from the NG that is not purchased.

Revenues from the selling of heat and cooling are not considered because the NPV analysis is a comparison between the baseline and proposed scenarios. In both of them these revenues are considered equal.

3.3. SENSITIVITY ANALYSIS

To analyse the influence of the inputs on the NPV, a sensitivity analysis is made. The inputs varied are the ones that influence more the results and the ones that vary more, namely, prices of biomass, NG and CO_2 emissions and the efficiency of the gasification process.

4. RESULTS AND DISCUSSION

4.1. TECHNICAL ANALYSIS

4.1.1 BASELINE SCENARIO

As referred in Chapter 3 the baseline scenario is modelled based in the data provided. Table 4.1 summarizes the results from the baseline scenario modelling and the comparison with the actual data.

2012	Modelling results in GWh	Actual data in GWh	Difference (%)
CHP heat production (with afterburning)	55.74	55.76	0.03
Auxiliary boiler heat production	5.29	5.27	0.3
Electricity production	32.33	38.44	17
Electricity exportation	14.35	not provided	-
Electricity importation	4.05	not provided	-
CHP (with afterburning) NG consumption	138.15	138.18	0.02
Auxiliary boiler NG consumption	5.57	5.55	0.4
Total fuel consumption	143.71	143.71	0

Table 4.1 – Baseline modelling results and comparison with the actual data.

As can be seen in Table 4.1, the modelled values of heat production and of fuel consumption are similar to the provided data values, this is due to the fact that, as explained in Chapter 3, the system was calibrated based on the values of heat production, until reaching percentage differences smaller than 1%. The bigger difference is in the electricity production, where the modelled value and the actual data value have a difference of 17%. As stated in the chapter 3.1.1, the CHP electricity production capacity is fixed and the model is producing at maximum electricity load just when it is producing at maximum heat load. In this way, increasing thermal capacity to match the heat demand would lower electricity production because the model is thermally overpowered and only uses the maximum heat capacity in the peaks, operating less time at maximum power capacity, resulting in lower electricity production on the model.

Since the plant operation is very different in the summer and in the winter, a summer and a winter weekday are analysed.

Although the production of electricity by the CCHP, there is still the need to import electricity. The CCHP plant is set to produce cooling from electricity (compression chillers) mostly during the night when the electricity price is low, storing cold water in the tank. Therefore, there is more electricity demand at night, resulting in electricity importation, especially in the summer, because there is no sufficient electricity production. This happens because the heat and electricity production are coupled. The electricity in excess during the day is sold to the grid at peak times. This can be observed in Figure 4.1, that shows

the importation and exportation of electricity in a day in August and in a day in January. In the summer, it can be noticed that, during the night, there is importation of electricity and during the day there is exportation to the grid. In the winter, there is only exportation because the electricity produced is sufficient for the demand due to the higher heat demand of winter. The electricity exportation peak occurs in the morning, 9 am -10 am and, also, there is a peak at night, 9 pm. For summer, it is interesting to verify that the periods of electricity importation coincide with the periods of cooling higher demand, because this electricity is mainly used on the compression chillers. For the same day, electricity importation occurred during the late afternoon, because the electricity production is not so high due to the low heat demand at that specific time.

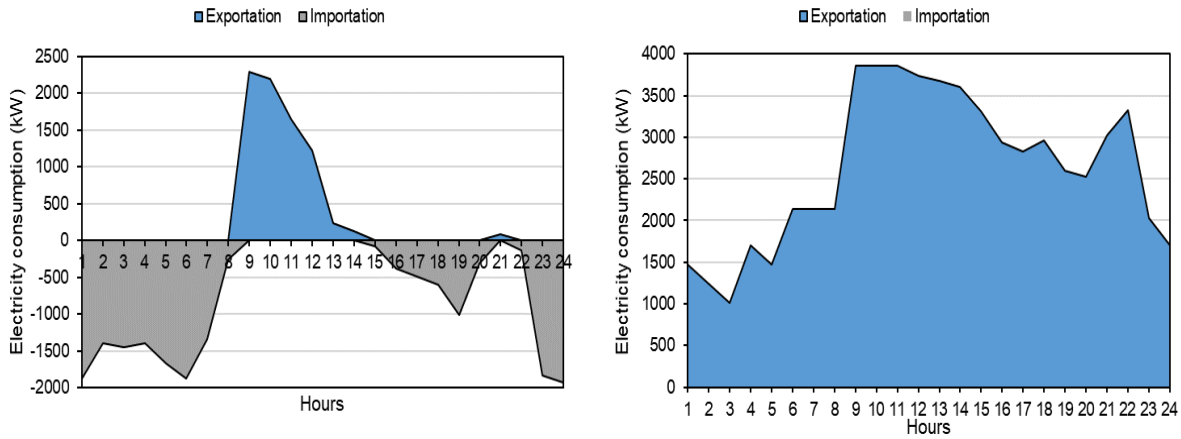


Figure 4.1 – Importation and exportation of electricity during a day in August, summer (left) and in January, winter (right).

Figure 4.2 shows the consumption and the exportation of electricity for both days. For the summer day, the exportation of electricity only occurs during the day as stated earlier. The cooling consumption is higher than in the winter day resulting in more electricity demand. As can be seen, the internal consumption excluding electricity for cooling is constant because the distribution is constant for all day in both season's days. For the winter day, since there is no importation in this day, all electricity consumed is produced from the CHP system. The electricity consumption for cooling production follows the cooling demand that is higher during the night. Also, there is a large amount of electricity exportation due to the low electricity necessity and higher heat demand, which results on excess of electricity production from the CHP.

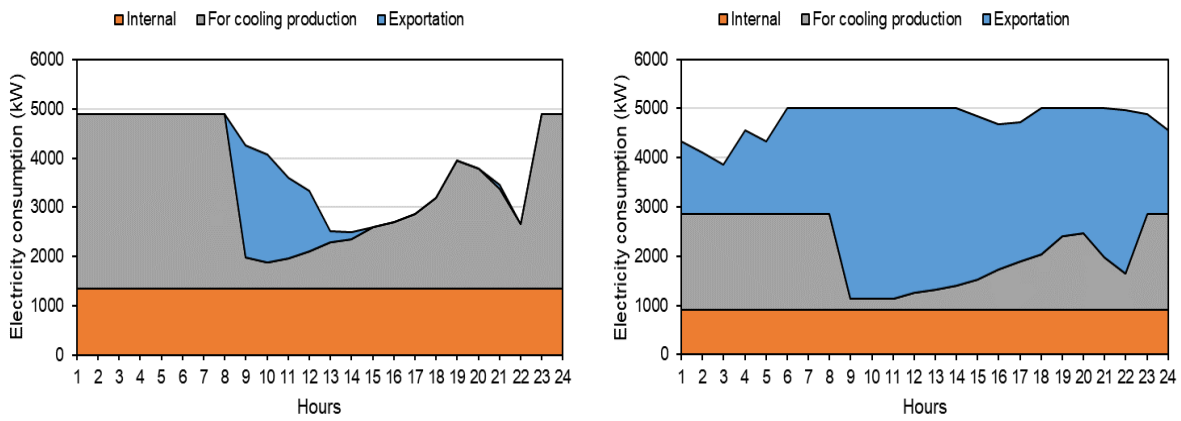


Figure 4.2 – Electricity consumption and exportation in the plant for a day in August, summer (left) and a day in January, winter (right).

Figure 4.3 shows the evolution of the total heating demand and the demand for cooling production in the absorption chillers for both days. It can be observed that the absorption chillers (heat for cooling demand) work more at night, because the distribution for both cooling demands is the same. As can be seen, in the winter the necessity of cooling is less than in the summer. It can be seen that the total heat demand is higher in the winter. The hourly load of the daily heat demand is possible to analyse also, with the peaks occurring during the morning and during the night between 8 am - 12 am and 19 pm - 21 pm. This indicates residential consumption peaks, although there are several types of consumers, the residential sector has a strong influence in these peaks.

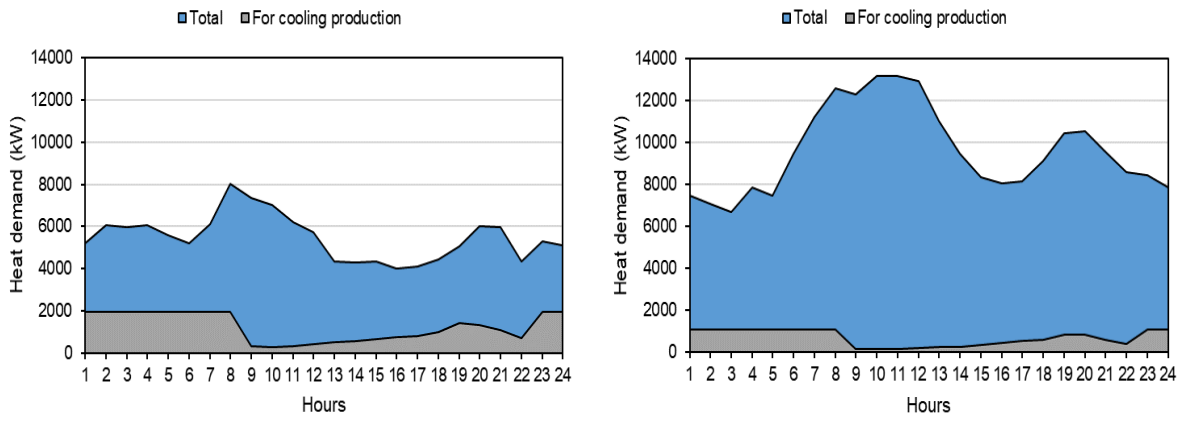


Figure 4.3 – Total heating demand and heating demand for cooling for a day in August, summer (left) and a day in January, winter (right).

Figure 4.4 shows the cooling production for the same days, where it can be observed that cooling is mainly produced from electricity. However, as referred earlier, the distribution input in the software is the same for both demands, so the proportion of each production in relation with the total production is equal along the year. In the reality, the period of working for the different chillers is not the same. The absorption chillers work only in periods where the heat is not needed to supply the clients. Despite this, it is possible to see the periods of more cooling production, at night. The cooling production load diagram

shape of the winter day is similar to the summer's one, however the values are much different with less cooling production in the winter. In the winter, there is still the necessity for cold water and this can be due to specific demand of some consumers such as the Lisbon Oceanarium.

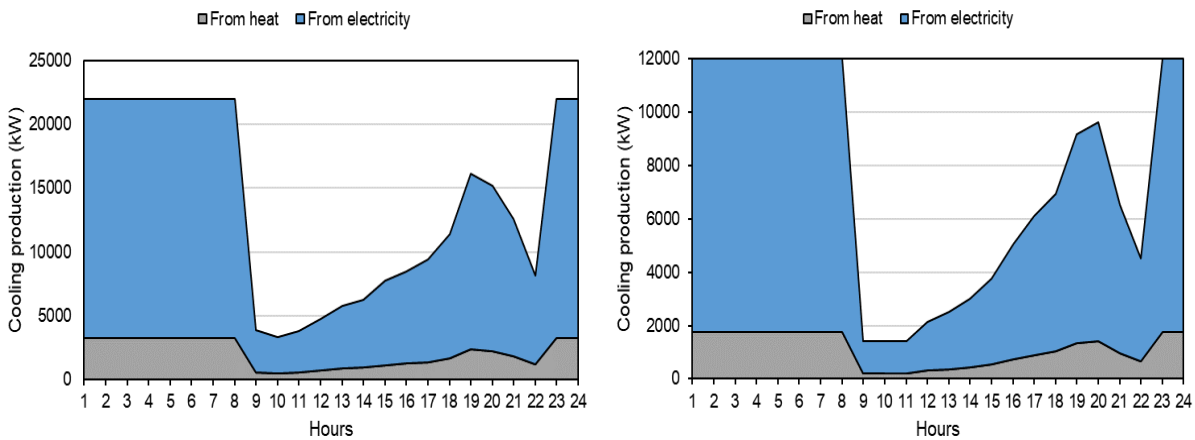


Figure 4.4 - Cooling production for a day in August, summer (left) and a day in January, winter (right).

The shape of the fuel demand curve for both days is similar to the shape of the heating demand curve. In the summer day, only the CHP system is working, the auxiliary boiler does not need to operate. Figure 4.5 shows distinctively the heat produced on CHP (with afterburning) system and on the auxiliary boiler for the day in the winter. In the winter, the heat peak loads are higher than in the summer and, in this sense to match this higher demand the auxiliary boiler needs to work since the CHP (with afterburning) does not have enough capacity.

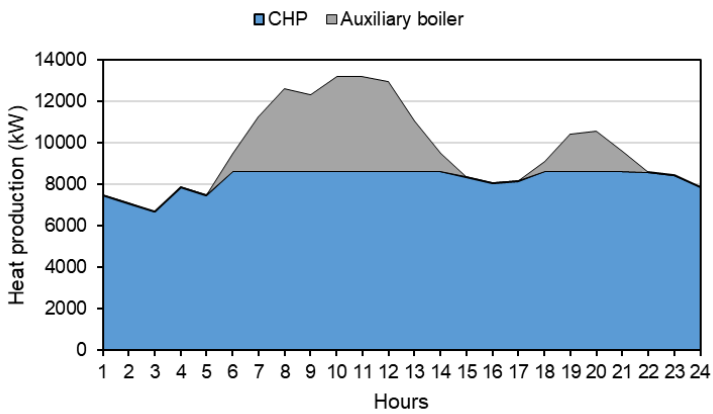


Figure 4.5 – CHP with afterburning and auxiliary boiler heat production for the day in January, winter.

4.1.2 CASE 1

As referred before, in case 1 the substitution of NG by bio-SNG from biomass is assessed, according to four different scenarios where different rates of substitution are taken into account. Table 4.2 shows

the results obtained for the different scenarios and the comparison with the baseline scenario. As can be seen, with the increase of gasification capacities, the electricity demand of the system increases. This results in a decrease of electricity exportation and an increase of its importation. The production of bio-SNG is linear along the scenarios. The modelling results for heating and cooling are not presented because no changes happen when compared with baseline scenario.

Scenarios	Baseline	25%Bio1	Difference (%)	50%Bio1	Difference (%)	75%Bio1	Difference (%)	100%Bio1	Difference (%)
Electricity demand in 2012 (GWh)	22.03	22.80	3.5	23.57	7.0	24.34	10.5	25.11	14.0
Exportation of electricity in 2012(GWh)	14.36	13.75	-4.3	13.14	-8.5	12.53	-12.7	11.93	-16.9
Importation of electricity in 2012(GWh)	4.05	4.21	4.0	4.37	7.9	4.54	12.1	4.71	16.3
Bio-SNG production in 2012(GWh)	-	35.93	-	71.85	-	107.78	-	143.71	-
Gasifier capacity (kW)	-	4,675	-	9,349	-	14,023	-	35,982	-
Upgrading capacity (kW)	-	4,090	-	8,180	-	12,270	-	16,360	-

Table 4.2 – Modelling results of Case 1 scenarios and comparison with the baseline.

The results regarding the electricity, heat and cooling production as well as fuel demand in the summer day are presented first and then the results for each scenario in the winter day are exposed.

Summer day

Figure 4.6 shows the electricity importation/exportation for the scenarios of case 1, for the same day of August considered in the baseline scenario. As biomass share increases, it is possible to observe the decrease of exportation and the increase of importation of electricity.

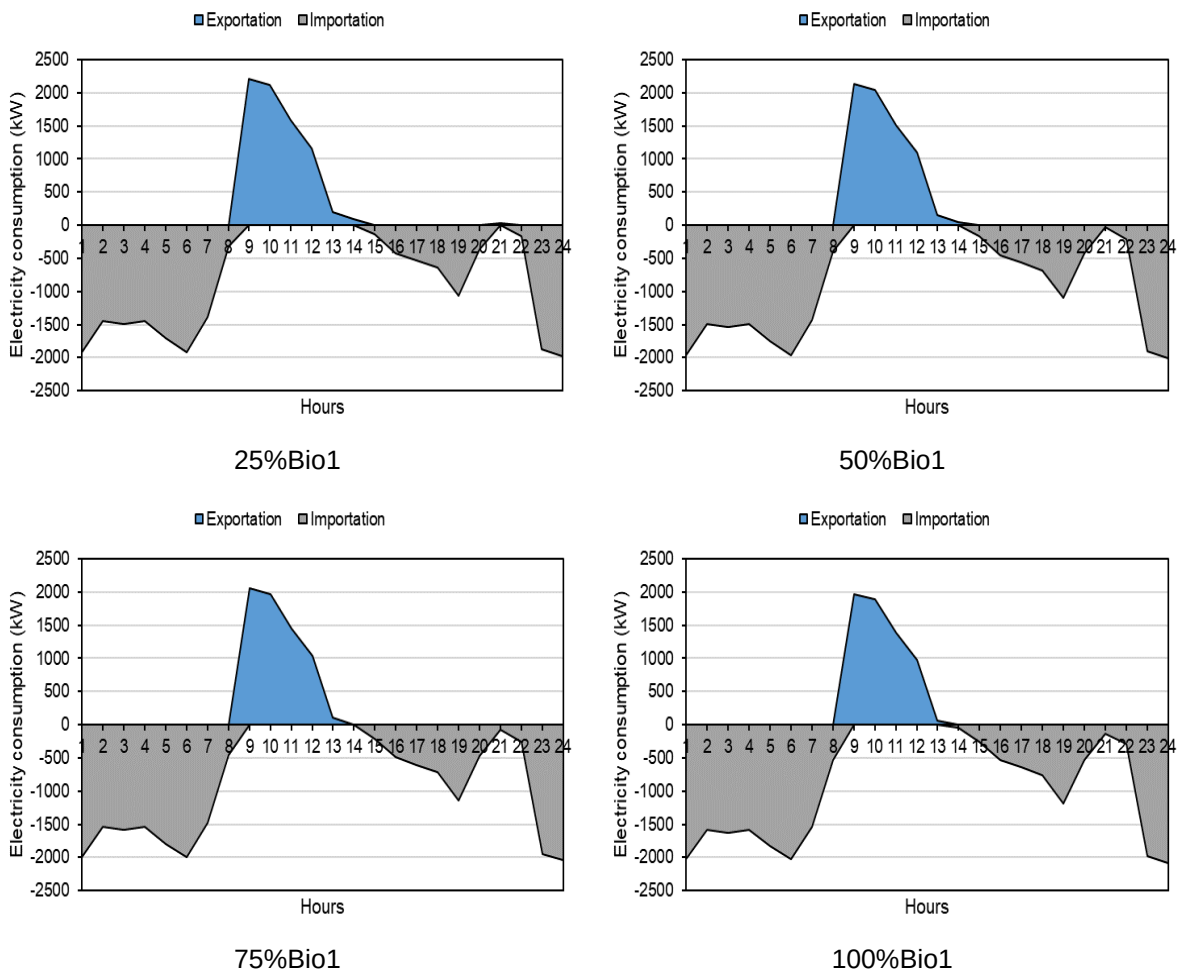


Figure 4.6 - Importation and exportation of electricity during a day in August - summer.

For this summer day, there is low electricity exportation as shown earlier. Figure 4.7 shows the consumption and the exportation of electricity for the summer day. It is possible to see the increase of internal electricity consumption due to the increase in gasification demand as biomass share increases. Since the electricity production is the same, the exportation decreases with the increase of internal consumption due to the gasification.

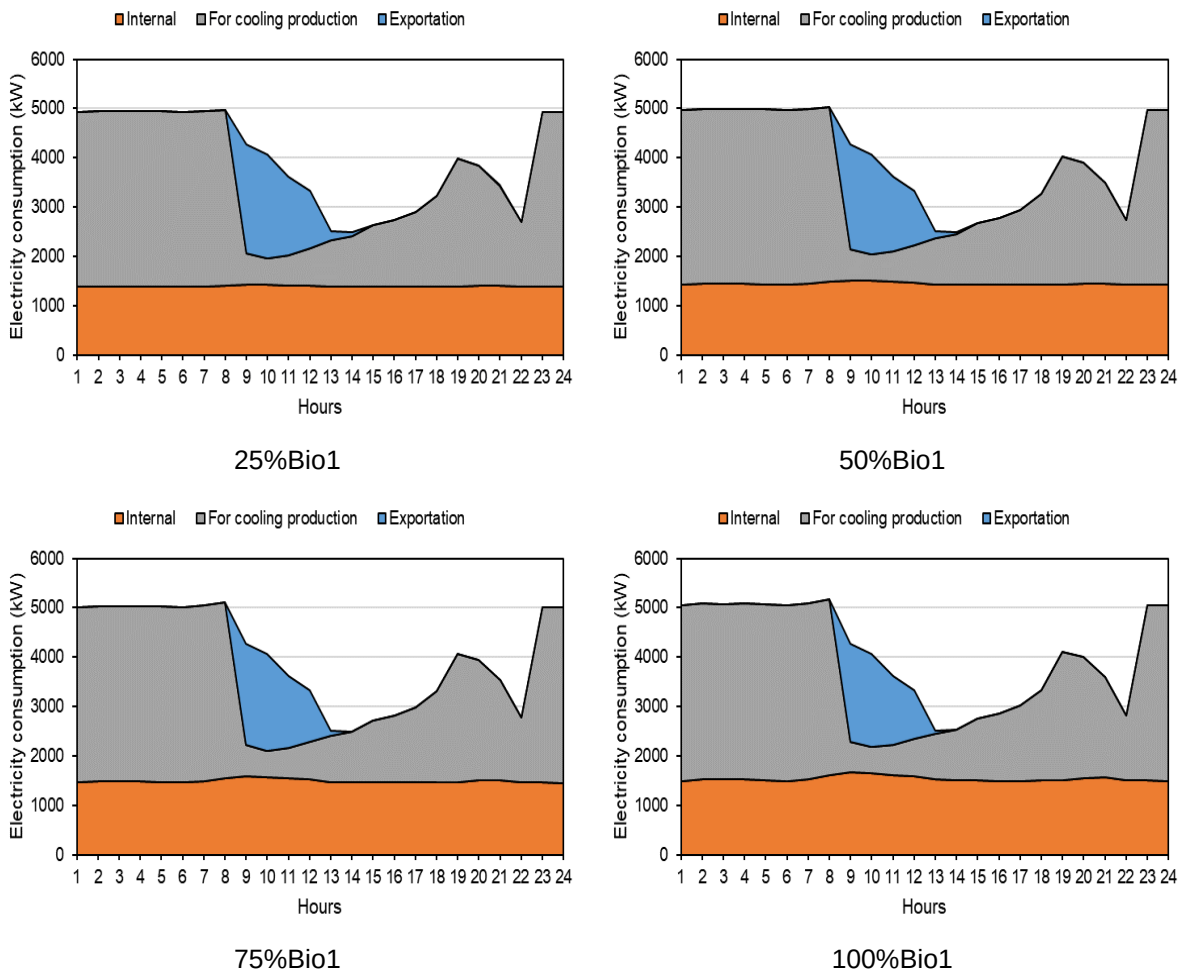


Figure 4.7 - Electricity consumption and exportation in the plant for a day in August – Summer.

Figure 4.8 shows the evolution of the production of bio-SNG for the different scenarios for the same day of August. The gasification process is provided with flexibility to avoid exportation to NG grid and to prevent NG importation. Such flexibility can be seen in the load diagram of bio-SNG production. When the demand is high, the gasifier uses the maximum capacity, but it can reduce the production when the demand is lower in order to not overproduce bio-SNG and consequently export gas. This is very notorious in the third scenario where a constant production would produce more than the demand during the afternoon. This flexibility allows the system to adequate the total production according to the demand. In the last scenario, all the fuel demand is fulfilled by bio-SNG.

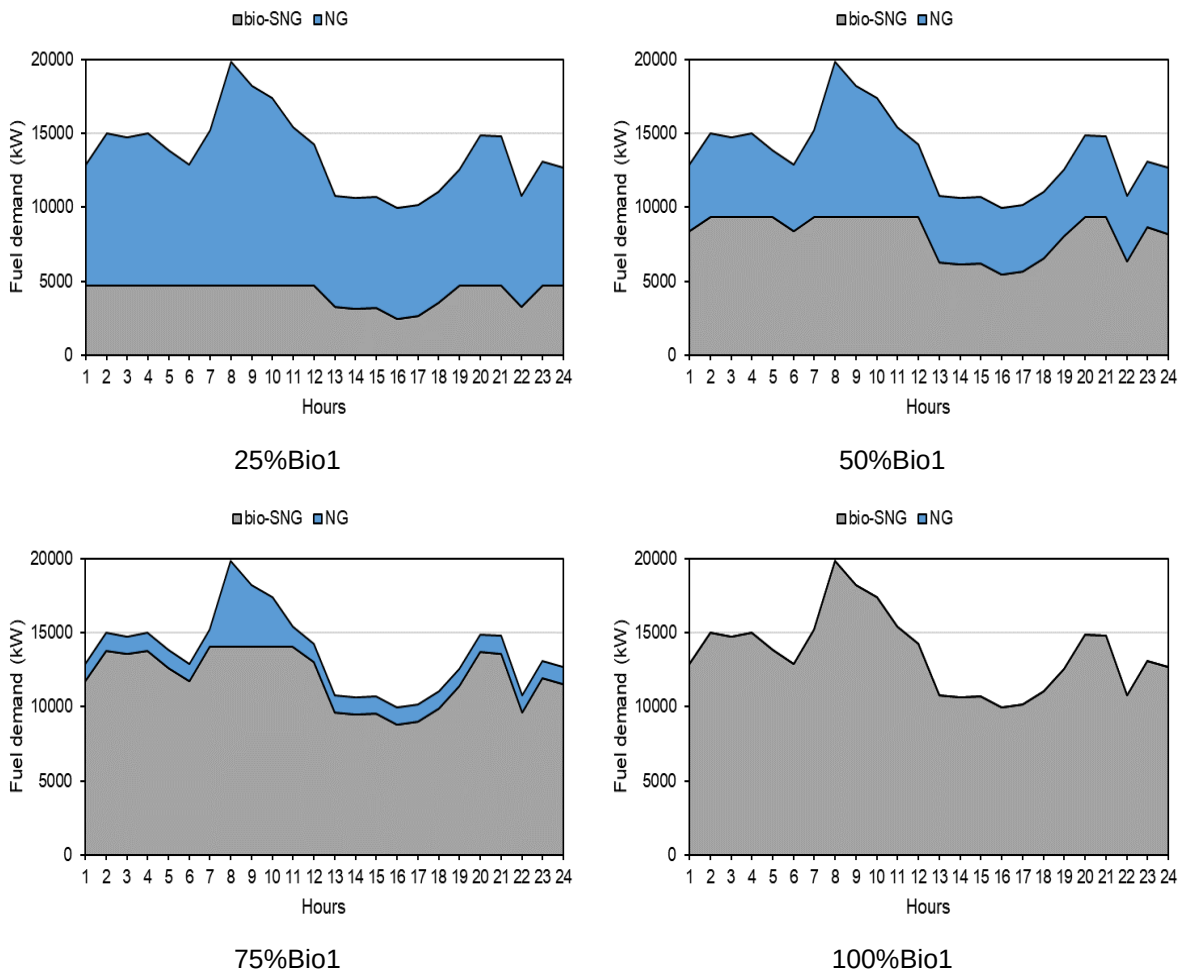


Figure 4.8 – Fuel demand for a day in August – Summer.

Winter day

Regarding the results obtained for the winter day, there are higher demands of heat, resulting in sufficient electricity production for internal consumption and even resulting in exportation of electricity. Figure 4.9 shows the exportation of electricity along the scenarios for the winter day. In this day, there is only exportation, so one image is presented for the four scenarios. As biomass share increases, the electricity exportation decreases.

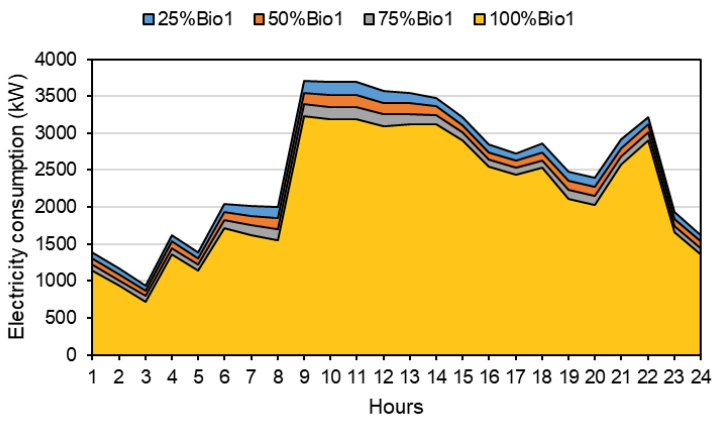


Figure 4.9 – Electricity exportation for a winter day.

Figure 4.10 shows the consumption and the exportation of electricity for case 1. It is possible to see the increase of internal electricity consumption due to the increase in gasification demand. Since the electricity production is the same, the exportation decreases with the increase of internal consumption due to gasification.

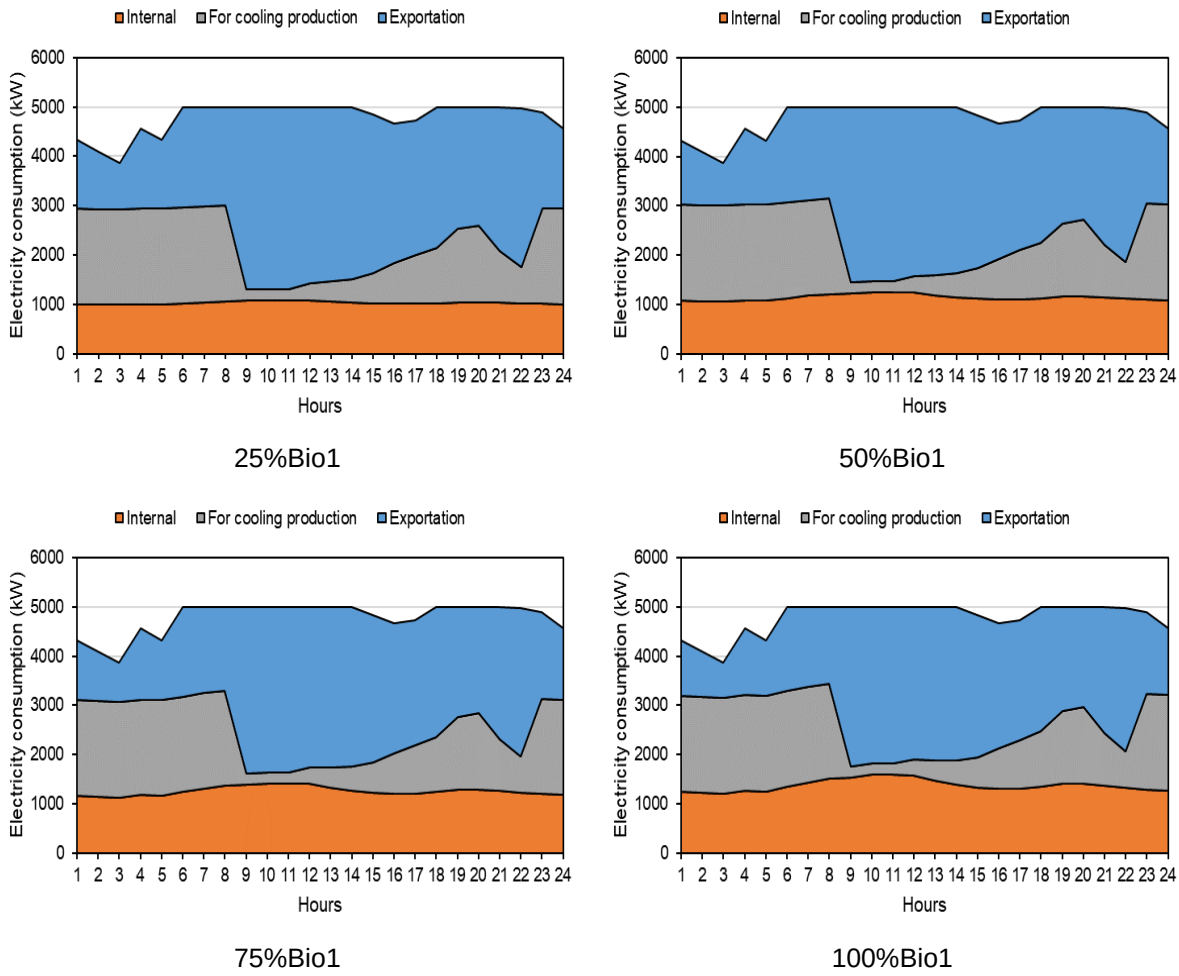


Figure 4.10 - Electricity consumption and exportation in the plant for a day in January – Winter.

Figure 4.11 shows the fuel demand for the day in January, winter. Contrary to the day in summer, bio-SNG production is constant along the day and the gasification process is working at maximum load capacity. This shows the flexibility of the process because there is more fuel demand in the winter and, in this sense, the gasification system can work at is maximum capacity for the three first scenarios. In the last scenario, there is flexibility accordingly to the load fuel demand.

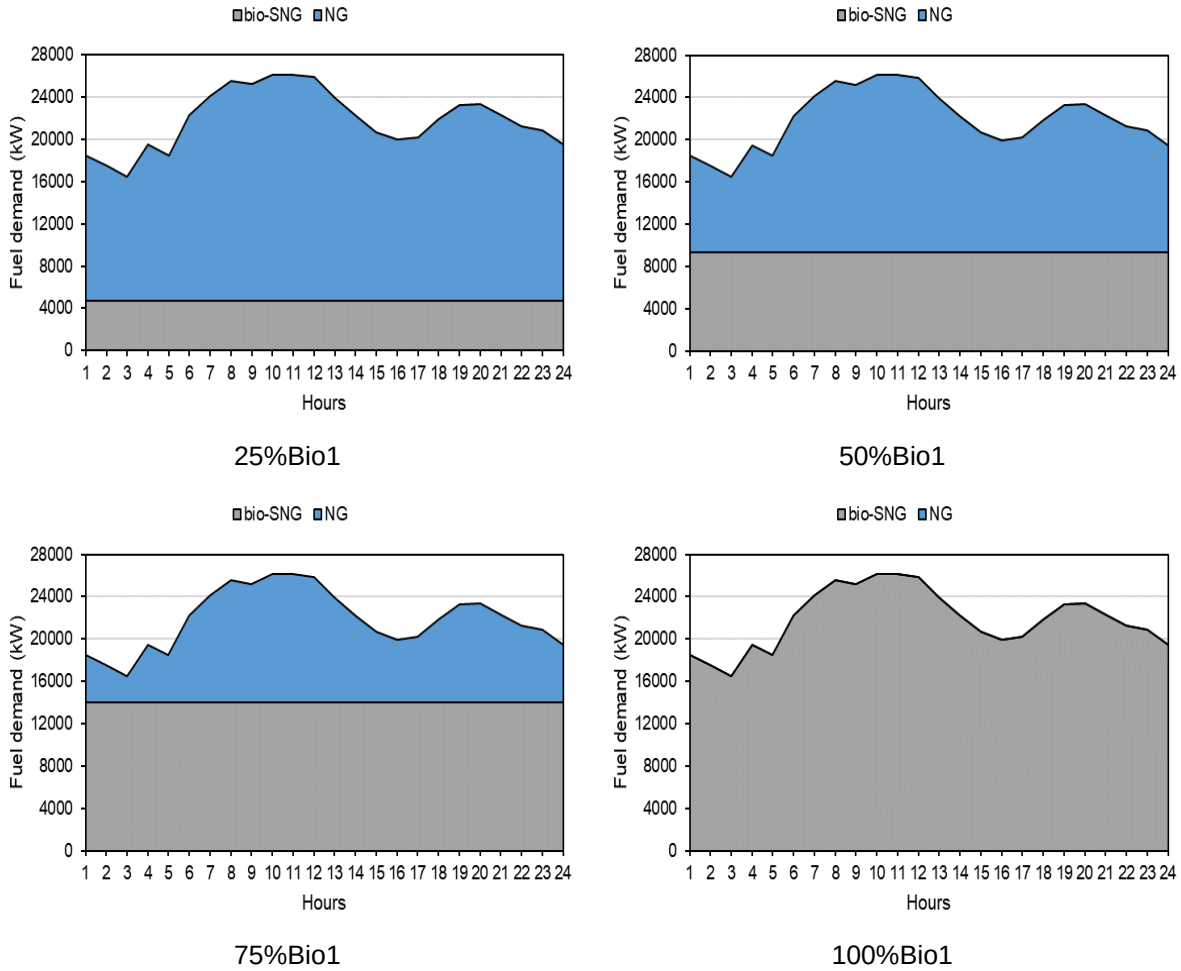


Figure 4.11 – Fuel demand for a day in January – Winter.

4.1.3 CASE 2

As referred earlier, in case 2 the substitution of NG by bio-SNG in the CHP system and the integration of an auxiliary biomass boiler are assessed, according to four different scenarios where different rates of substitution are take into account. Table 4.3 shows the difference in the electricity and gas grid in relation with the baseline scenario. As in case 1, with the increase of gasification capacities, the electricity demand increases. This results in a decrease of exportation and an increase of importation of electricity. The production of bio-SNG is not linear along the scenarios because the biomass boiler

has the same heat production along the scenarios. Again, heat and cooling values are not presented because no changes happen when compared with the baseline scenarios.

Scenarios	Baseline	25%Bio2	Difference (%)	50%Bio2	Difference (%)	75%Bio2	Difference (%)	100%Bio2	Difference (%)
Electricity demand in 2012 (GWh)	22.03	22.68	3.0	23.45	6.5	24.22	9.9	24.99	13.4
Exportation of electricity in 2012 (GWh)	14.36	13.84	-3.6	13.23	-7.9	12.63	-12.1	12.03	-16.2
Importation of electricity in 2012 (GWh)	4.05	4.19	3.5	4.35	7.4	4.51	11.4	4.68	15.6
Bio-SNG production (GWh)	-	30.36	-	66.29	-	102.22	-	138.14	-
Gasifier capacity (kW)	-	3,951	-	8,625	-	13,299	-	21,364	-
Upgrading capacity (kW)	-	3,456	-	7,547	-	11,636	-	15,727	-

Table 4.3 - Modelling results of Case 2 scenarios and comparison with the baseline.

Some results for case 2 are very similar of those from case 1, namely regarding the importation and exportation of electricity and, in this sense are not presented here. In relation with case 1, there is less importation and more exportation of electricity because there is less need of the gasification system, however the difference is not significant. Figure 4.12 represents the fuel demand for the winter day. In the summer day, there is no need for the boiler to work so the greater difference for case 2 is in the fuel demand for the winter day. It is possible to see the constant value of biomass for the boiler along the scenarios. Also, it is possible to see that like in the case 1, the production of bio-SNG is constant along the day, working at maximum capacity during the winter day because there is more fuel demand. As stated earlier, the production of bio-SNG is not linear across the scenarios, which can be seen in the Figure 4.12.

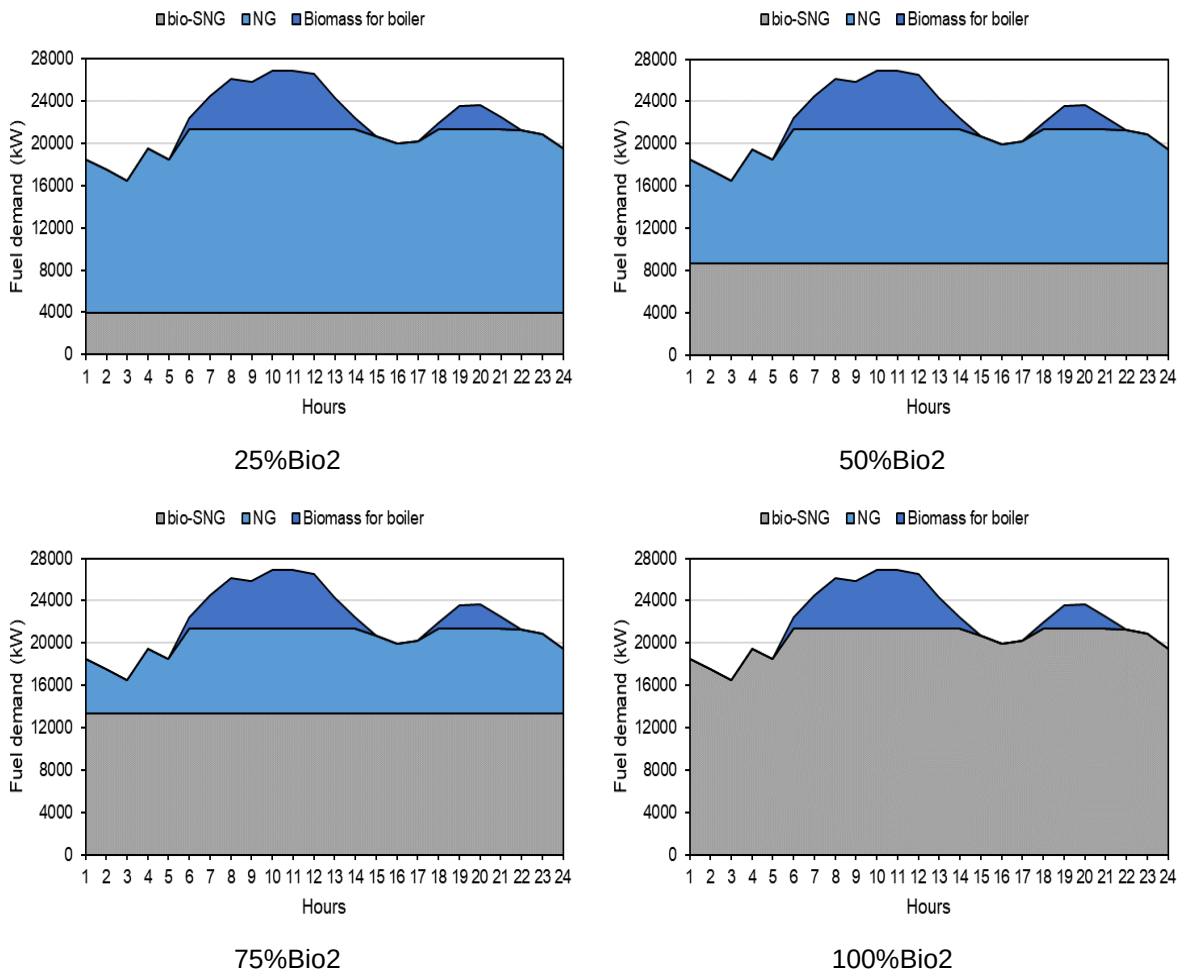


Figure 4.12 – Fuel demand for a day in January - Winter.

4.2. CO_2 EMISSIONS ANALYSIS

Other aspect approached in the present thesis is the CO_2 emissions due to the use of NG in the CCHP plant. It is shown in Table 4.4, as one should expect, that the CO_2 emissions decrease with the increasing share of biomass. The trend is linear along the scenarios since truck emissions for biomass transportation are not considered. As discussed earlier, biomass CO_2 emissions are considered to be zero.

Scenario	Baseline	25%Bio1 25%Bio2	50%Bio1 50%Bio2	75%Bio1 75%Bio2	100%Bio1 100%Bio2
CO_2 emissions (kton CO_2)	29.02	21.77	14.51	7.26	0

Table 4.4 - CO_2 emissions for each scenario.

4.3. FINANCIAL ANALYSIS

The study is focused on the modelled case simulated in the EnergyPLAN, therefore all the calculations are related to the model. For the baseline scenario, the NG importation costs are 3983.54 k€ and the CO_2 emissions costs are 155.27 k€. When avoided costs are referred or calculated, they are related to these values.

4.3.1 CASE 1

Table 4.5 shows a resume of the investment, as well as, the costs and revenues per year for each scenario in the case 1. The gasifier and the upgrading system are purchased on the year zero and their costs are annualized with a CRF. The other costs and revenues are the ones considered at the end of each year. The biggest costs for all the scenarios are the biomass costs. O&M costs depend exclusively on the gasifier and upgrading system since the calculations are done in comparison with the reference scenario, where there is no gasifier and upgrading system's. The difference between the electricity revenue from the baseline scenario is also assessed, since with the increase of the gasifier and of the upgrading system size, the exported electricity is reduced because some electricity is consumed by the process. However, the selling price of electricity increases after the use of 50% of primary energy from renewable sources, which results in significant changes along the scenarios.
The last scenario has higher costs in relation with the other scenarios, because the gasification capacity needed is much bigger, which increases the O&M costs that have a great weight in the costs.

Scenarios	25%Bio1	50%Bio1	75%Bio1	100%Bio1
Annualized Costs (k€)				
Gasifier	146.28	292.54	438.79	1125.90
Upgrading System	126.34	252.67	379.01	505.34
Biomass costs	625.97	1251.94	1877.91	2503.88
O&M costs	292.85	585.69	878.52	1537.79
Revenues (k€)				
CO_2 emissions cost avoided	38.82	77.64	116.45	155.27
NG costs avoided	995.88	1991.77	2987.65	3983.54
Electricity revenue difference from reference scenario	-53.25	-9.66	-67.41	-124.22

Table 4.5 – Resume of annual costs and revenues from case 1.

Figure 4.13 shows the weight of each cost for the different scenarios in case 1. It is possible to observe that the biomass costs have the higher weight and are responsible for a little bit more than 50% of the total costs for the first three scenarios, for the last one, biomass costs are approximately 44%. The weight of the gasification infrastructure costs is higher in the last scenario, as well as the O&M's costs inherent to them.

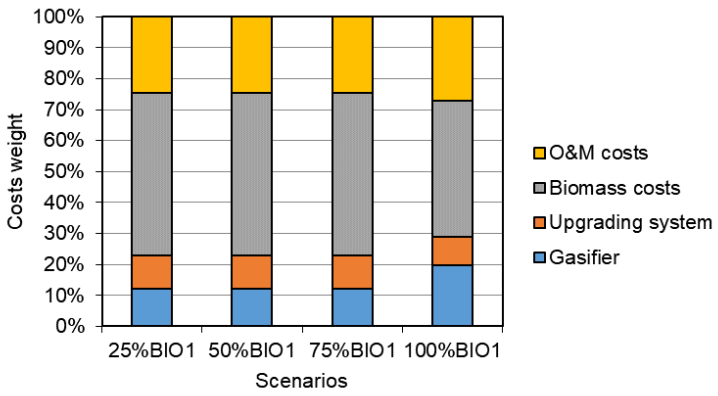


Figure 4.13 – Costs weight for the different scenarios in case 1.

With all the assumptions and values assumed in the previous chapter, the NPV and the Payback Period were calculated. Table 4.6 shows the results for each scenario considered. All the scenarios have negative NPV in the time considered, therefore there is no PB.

Scenarios	25%Bio1	50%Bio1	75%Bio1	100%Bio1
NPV (M€)	-2.57	-3.90	-6.53	-20.58

Table 4.6 - NPV results for case 1 regarding all the scenarios.

Figure 4.14 shows the NPV for each scenario.

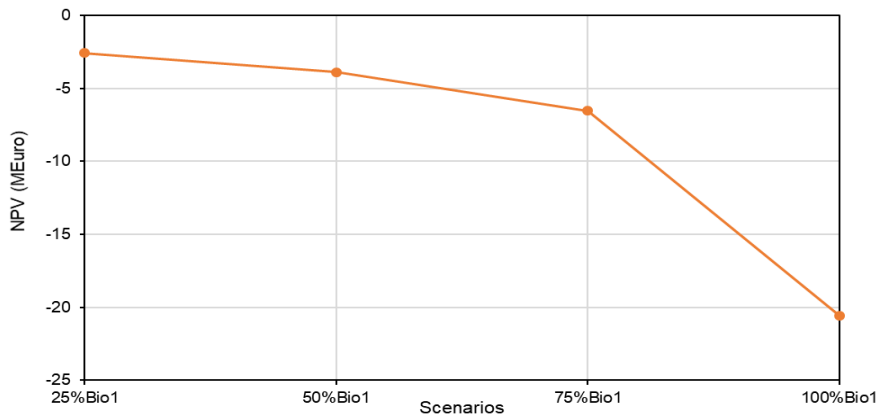


Figure 4.14 - NPV for each scenario for case 1.

It is possible to observe that there is a decrease in the values of NPV with the increase of the share of biomass in the CCHP system. This is mainly due to the incapacity of the revenues to recover the initial investment of the gasification equipment and the yearly costs. With the increase of biomass consumption, the gap between the sum of the initial investment and the yearly costs with the profits increases along time. It can be verified that there is a change in the slope between 25%Bio1-75%Bio1

and 75%Bio1-100%Bio1. This can be explained by a significant increase in the gasification power capacity in the second slope in relation with the first one.
The 100%Bio1 is highly negative, which results from the high gasification capacity needed to match the heat peak loads, which increases significantly the costs.

4.3.2 CASE 2

Table 4.7 summarizes the investment costs as well as the costs and revenues for each scenario in case 2. As in the previous case, the gasifier, the upgrading system and the biomass boiler are purchased on the year zero, and the investment done is annualized with CRF. The other costs and revenues are the ones considered at the end of each year. The results show that the major costs for all the scenarios are the biomass costs as in case 1. It can also be verified that the O&M costs, like case 1, depend exclusively on the gasifier and upgrading system capacity. The difference between the electricity revenue from the baseline scenario is lower than in case 1 due to the lower electricity consumption of the gasification system in case 2.
Also, it is possible to see the non-linearity of the increasing costs of the gasification system. The gap between the first and last scenario is not so huge as in case 1. This occurs because the fuel peak load demands are now fulfilled by the biomass boiler and not by the gas engines all alone. As result, the gasification capacity needed decreases because the bio-SNG demand is lower in the peak loads. Since the boiler produces the same heat along the scenarios, there is no linearity in the bio-SNG production.

Scenarios	25%Bio2	50%Bio2	75%Bio2	100%Bio2
Annualized Costs (k€)				
Gasifier	123.63	269.88	416.14	668.49
Upgrading System	106.75	233.12	359.42	485.79
Biomass Boiler	98.08	98.08	98.08	98.08
Biomass costs	607.00	1232.97	1858.94	2484.91
O&M costs	264.01	556.89	849.67	1214.44
Revenues (k€)				
CO_2 emissions cost avoided	38.82	77.64	116.45	155.27
NG costs avoided	995.88	1991.77	2987.65	3983.54
Electricity revenue difference from reference scenario	-45.40	-1.14	-57.95	-114.75

Table 4.7 - Resume of annual costs and revenues from case 2.

Figure 4.15 shows the weight of each cost category for the different scenarios in case 2. The weight of the different costs is similar for all scenarios. It is possible to observe that the biomass costs are again the principal costs and are responsible for a little bit more than 50% of the total costs for all the scenarios. The weight of the gasification system as well as of the O&M costs increase along the scenarios. For this

case, since the biomass boiler has the same capacity for all the scenarios, its price is equal. As result, its cost's weight decreases along the scenarios.

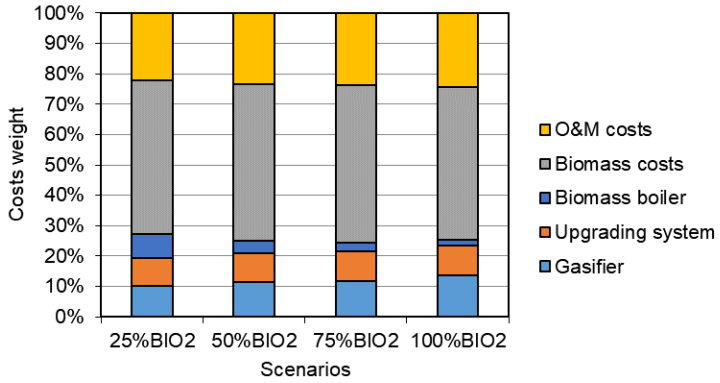


Figure 4.15 – Costs weight for the different scenarios in case 2.

As in case 1, NPV and PB period are calculated for case 2, the case in which the plant would acquire a biomass boiler for direct combustion to match the peak loads. Table 4.8 shows the results for the scenarios analysed. Again, all the scenarios have negative NPV and their values are similar with those in case 1 except for the last scenario. The objective of introducing the boiler was to reduce the investment and O&M costs related to the gasification system since these costs are responsible for a significant percentage of costs. Since the heat produced by the boiler is just approximately 8.6%, it has no big impact in the financial analysis because there are investment costs inherent to its acquirement.

Biomass %	25%Bio2	50%Bio2	75%Bio2	100%Bio2
NPV (M€)	-2.57	-3.90	-6.51	-11.37

Table 4.8 - NPV results for case 2 regarding all the scenarios.

Figure 4.16 shows the NPV for each scenario. It is possible to observe that there is a decrease in the values of NPV along the scenarios. Again, this is due to the incapacity of the revenues to recover the initial investment of the gasification equipment and the yearly costs. With the increase of biomass demand, the gap between the sum of the initial investment and of the yearly costs with profits along time increases. It is possible to see a notorious difference in the slope between 25%Bio2-50%Bio2 and 50%Bio2-100%Bio2, because the investment is increasing but the profits stayed almost constant after the 50% scenario.

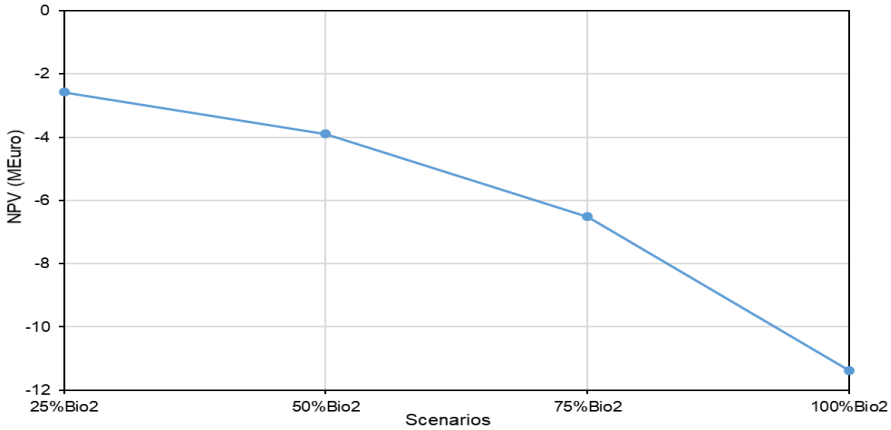


Figure 4.16 - NPV for each scenario for case 2.

4.3.3 COMPARISON BETWEEN THE TWO CASES

Results presented in Table 4.9 show that case 2 has in total slightly higher costs than case 1 except for the last scenario. In fact, these higher costs are due to the investment costs related to the gasification system and to the boiler, since the biomass and O&M costs are lower in case 2. This is due to the reduction of the gasification needs with the addition of the boiler. The last scenario of case 1 presents higher costs. This is because the gasification capacity needed is much bigger than the one of case 2 due to the need to match the peaks with bio-SNG combustion. Also, less quantity of biomass is needed in case 2 because some part of biomass is for direct combustion, which has higher efficiency than gasification process, so less cost.

Scenarios	25%Bio		50%Bio		75%Bio		100%Bio	
	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2
Annualized Costs (k€)								
Gasifier	146.28	123.63	292.54	269.88	438.79	416.14	1125.90	668.49
Upgrading System	126.34	106.75	252.67	233.12	379.01	359.42	505.34	485.79
Biomass boiler	-	98.08	-	98.08	-	98.08	-	98.08
Biomass costs	625.97	607.00	1251.94	1232.97	1877.91	1858.94	2503.88	2484.91
O&M costs	292.85	264.01	585.69	556.89	878.52	849.67	1537.79	1214.44
Total costs	**1191.44**	**1199.47**	**2382.84**	**2390.94**	**3574.23**	**3582.25**	**5672.91**	**4951.71**
Revenues (k€)								
CO_2 emissions cost avoided	38.82	38.82	77.64	77.64	116.45	116.45	155.27	155.27
NG costs avoided	995.88	995.88	1991.77	1991.77	2987.65	2987.65	3983.54	3983.54
Electricity revenue difference from reference scenario	-53.25	-45.40	-9.66	-1.14	-67.41	-57.95	-124.22	-114.75

Table 4.9 - Comparison of costs and revenues for the two cases.

Figure 4.17 shows that both cases have similar NPV except for the last scenario where there is a bigger difference, about 58%. The difference in the last scenario is very high due to the gasification system capacity and related O&M costs.

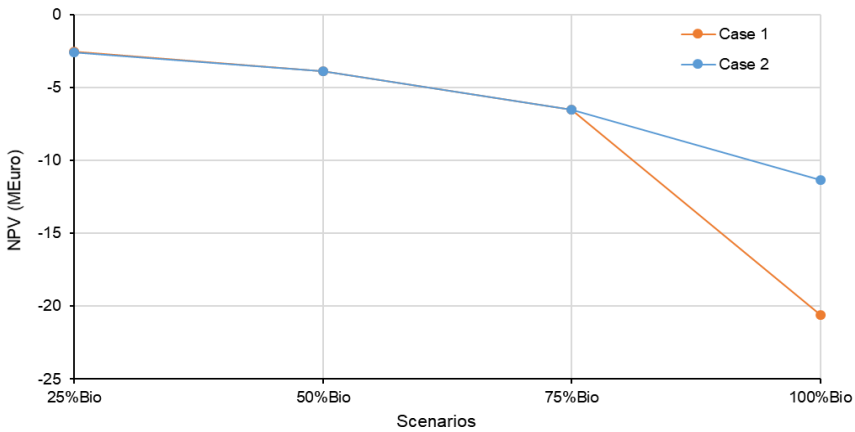


Figure 4.17 - Comparison of the NPV along the scenarios for case 1 and 2.

4.4. SENSITIVITY ANALYSIS

In this section, a sensitivity analysis is done to the parameters that have a higher impact in the costs or in the revenues and, also to the parameters which costs variation can be wide.

Based in the Figure 4.18, which presents the biomass price in different countries for each trimester, from mid-2006 until the beginning of 2011, the sensitivity analysis a to the biomass price is done considering a price variation of ±40% [48]. With the variation proposed the prices range from 2.03 €/GJ to 4.74 €/GJ.

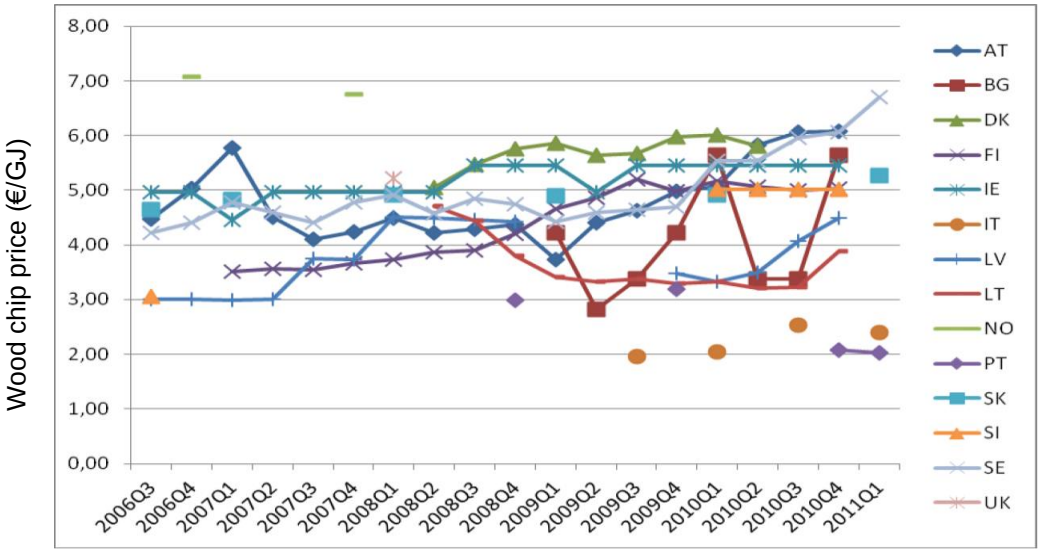


Figure 4.18 – Wood chip price variation (industrial market) from mid-2006 until the beginning of 2011. Different lines for different countries (adapted from [48]).

For the NG price, the sensitivity analysis is done considering a price variation of ±30% based on the average German import price variation from 2008 until 2015 showed in Figure 4.19 [49]. This data can give a notion of the volatility of the NG market price. Since the prices range from 6 $/MBtu to 12 $/MBtu, it agrees with the used variation of ±30% (5,39 €/GJ -10,01 €/GJ).

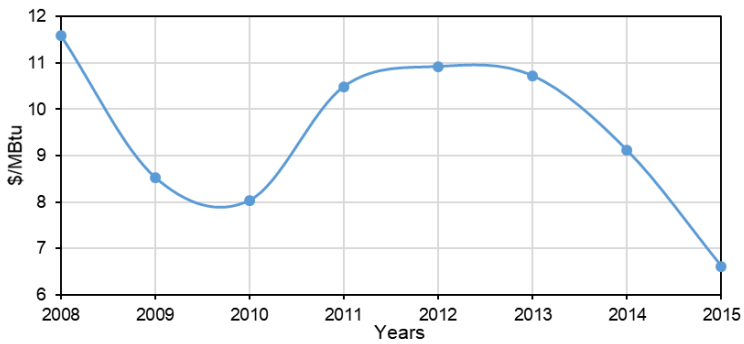


Figure 4.19 - Price evolution for the average German import price (adapted from [49]).

For the price of CO_2 emissions, a variation of ±50% was applied. The EU ETS market started in 2005, and the CO_2 allowances price has been very inconstant along the operation period. In Figure 4.20 it is

possible to see the evolution of the average annual price from 2008 to 2016 [47]. As can be seen, the price is significantly volatile with an observable decrease in general, so a variation of ±50% is considered with the values ranging from 2,675 €/GJ to 8,025 €/GJ. Since the CO_2 emission costs reached an average of 26.86 €/ton in June 2008 [47] (almost in the beginning of the market), the NPV for this value is calculated for all the scenarios.

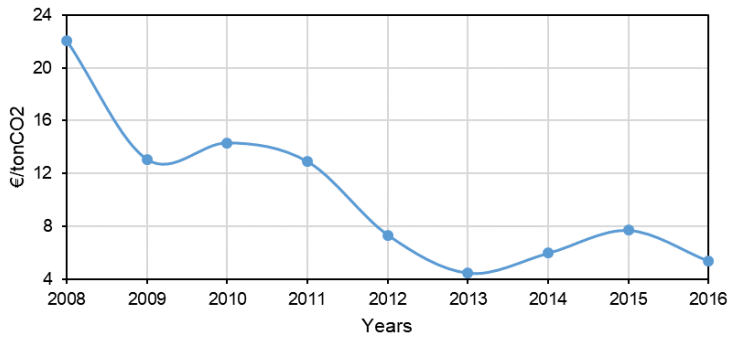


Figure 4.20 - Price evolution for the CO_2 emissions price (adapted from [47]).

For the gasification efficiency, a range from -20% (54%) to 10% (74,25%) is chosen based on the literature [22,42].

Table 4.10 shows the values used for the sensitivity analysis.

% Variation	NG price (€/GJ)	Biomass price (€/GJ)	CO_2 emission price (€/ton)	Gasification biomass-SNG efficiency (%)
-50%	-	-	2,68	-
-40%	-	2,03	3,21	-
-30%	5,39	2,37	3,75	-
-20%	6,16	2,71	4,28	54,00
-10%	6,93	3,05	4,82	60,75
0%	7,70	3,39	5,35	67,50
10%	8,47	3,73	5,89	74,25
20%	9,24	4,07	6,42	-
30%	10,01	4,40	6,96	-
40%	-	4,74	7,49	-
50%	-	-	8,03	-

Table 4.10 – Values variation for the sensitivity analysis.

4.4.1 CASE 1

Figure 4.21 shows the NPV Sensitivity Analysis for each scenario regarding the case 1, where the NG is only substituted by bio-SNG. The black line is placed in the NPV=0 for better demonstration of the turning point. An increase in the NG price turns the NPV more positive because the avoided costs are

higher. The increase of biomass price results in more negative NPV because it increases the scenario cost. It is possible to observe that the project feasibility is strongly dependent on the NG and biomass price. On the contrary, the CO_2 emissions price does not influence much the results. The total efficiency of the process (from biomass to bio-SNG) also strongly influences the NPV result because the biomass quantity to be bought is dependent on the efficiency of the process. However, a 10% increase in the gasification efficiency does not turn the project NPV positive for any scenario. For the 25%Bio1 scenario, an increase of 30% in NG price and a decrease in 40% of biomass price turns the NPV positive. Also, it is possible to observe that an increase of more than 20% in NG price would turn the NPV positive for the 50%Bio1 and 75%Bio1 scenarios. The same is true if biomass price decreases more than 30%. The last scenario never has a positive NPV for any value variation. Table 4.11 summarizes the PB for the positive NPV scenarios.

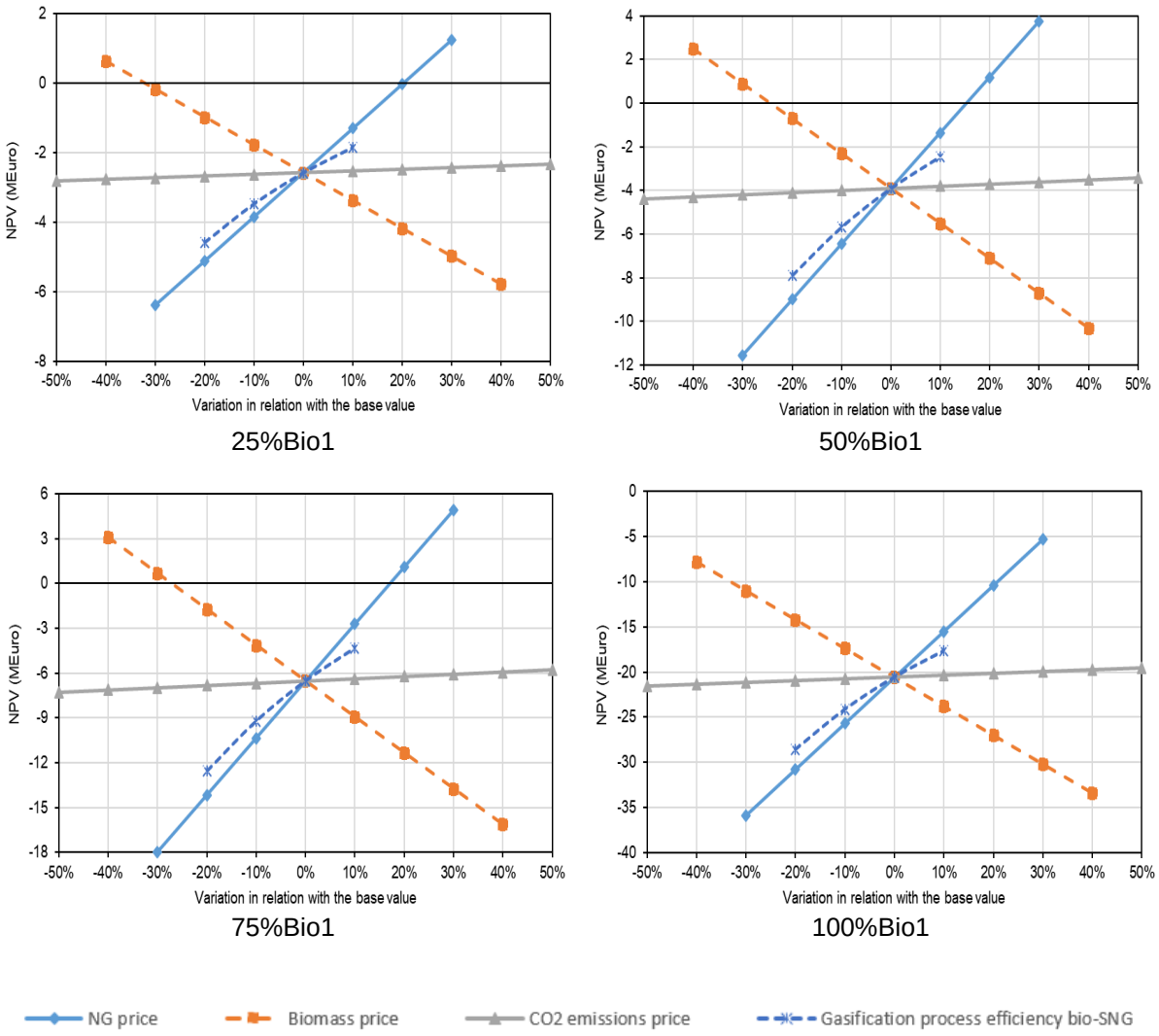


Figure 4.21 – NPV sensitivity analysis for case 1.

PB (years)	NG price variation		Biomass price variation	
	+20%	+30%	-30%	-40%
25%Bio1	-	1.3	-	0.6
50%Bio1	1.2	3.7	0.9	2.5
75%Bio1	1.1	4.9	0.7	3.1

Table 4.11 – PB values for the positive NPV scenarios.

In order to assess the impact of the two most influential values, NG and biomass prices, in the NPV sensitivity analysis, a comparison between all the scenarios for each price variation is carried out for case 1.

Figure 4.22 shows clearly the NPV sensitivity analysis comparison of all the scenarios considered in function of the NG (left) and biomass (right) price variation. First, it is possible to see that the 75%Bio1 scenario is financially the best scenario if an increase of 30% in NG price or a 40% reduction in biomass prices occurs. Also, if the contrary happens, the less negative NPV scenario is the first one. As stated earlier, the last scenario has a highly negative NPV that does not turn positive for any price variation. Finally, it can be seen that the NG price has more impact than the biomass price.

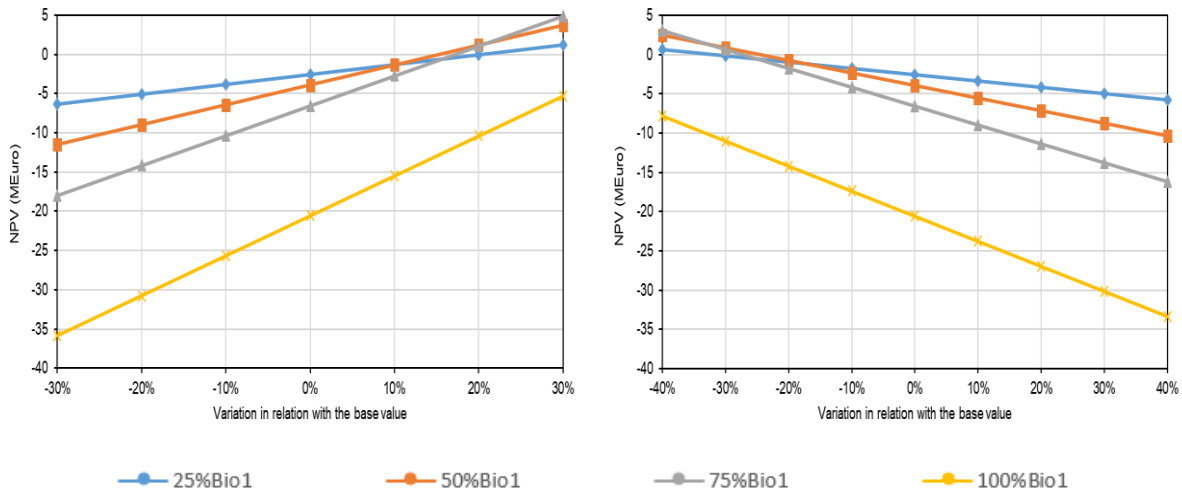


Figure 4.22 – NPV sensitivity analysis comparison of all the scenarios in function of NG (left) and biomass (right) prices.

4.4.2 CASE 2

The NPV sensitivity analysis for case 2 is carried out. Results reveal that the NPV sensitivity analysis for this case is very similar to case 1, as they have almost the same NPV values, except for the last scenario. Since the last scenario is the most different, a comparison between the last scenario of the two cases is presented. Figure 4.23 illustrates the comparison of the NPV Sensitivity Analysis for each value variation, for the last scenario of both cases. The black line is placed in the NPV=0 for better demonstration of the turning point. As can be seen, a 30% increase in NG price and a 40% decrease in

biomass price turn the NPV positive for the last scenario of case 2. This shows that for this case study, a 100% renewable system with biomass is possible with those price values. For the 30% increase in NG price, the PB is 3,9 years and for the 40% reduction in biomass price, the PB is 1.3 years.

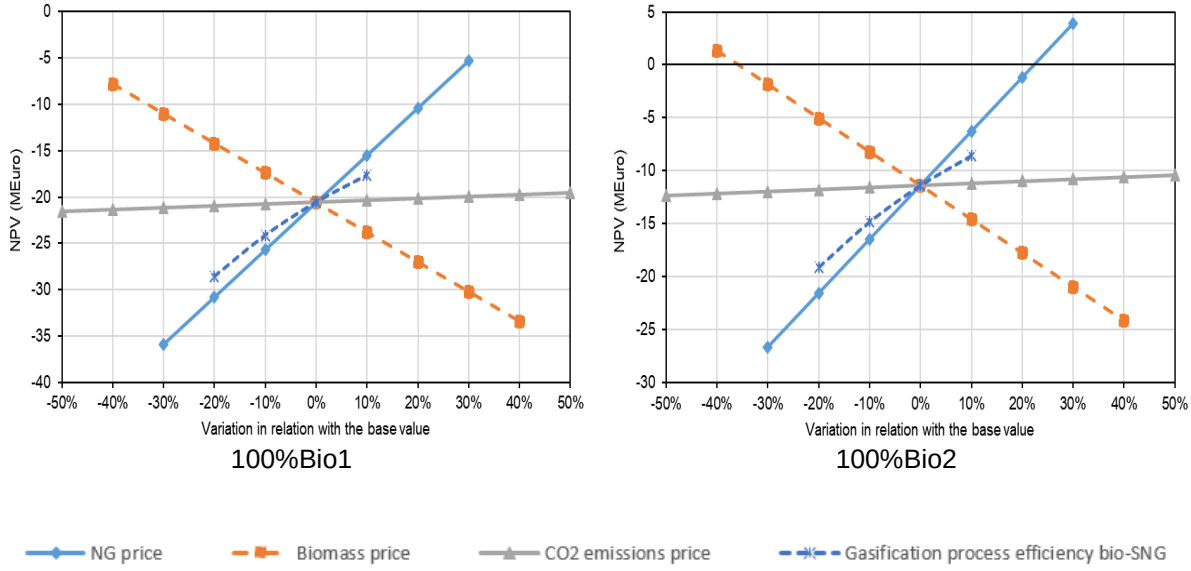


Figure 4.23 – NPV sensitivity analysis comparison for the last scenario of both cases.

4.4.3 CO_2 EMISSIONS PRICE VARIATION

Since CO_2 emissions cost reached 26.86 €/ton, a NPV analysis for both cases is carried out for that value. The results are presented in the Table 4.12. The scenarios with 50% of biomass share are the only ones with positive NPV for that value of CO_2 emissions' cost. The payback period is approximately 25 years for these scenarios.

NPV (MEuro)	25%Bio	50%Bio	75%Bio	100%Bio
Case 1	-0.575	0.088	-0.544	-12.601
Case 2	-0.579	0.092	-0.527	-3.391

Table 4.12 – NPV values for a CO_2 emissions cost of 26.86 €/ton.

5. CLOSURE

5.1. CONCLUSIONS

In this study, a replacement of NG by biomass gasification is proposed to reduce the fossil fuel consumption and the inherent CO_2 emissions in an existent CCHP located in the East of Lisbon that operates in a new district since 1998. A technical and financial analysis are carried out.

Based on the heat and cooling demand of the CCHP plant, first a baseline scenario and then two cases, each with different scenarios, are built and modelled using EnergyPLAN. For the first case, only the fuel is replaced; in the second case the fuel and the existent auxiliary boiler are replaced.

The technical analysis is carried out with the help of EnergyPLAN, firstly by setting up the baseline scenario and then by integrating the gasifier technology in the Climaespaço system as well as the new boiler for the second case. Two EnergyPLAN limitations were faced. The first was the impossibility of increasing the CHP thermal power due to the afterburning without increasing the model error in the electricity production. The second limitation was in the cooling demand because the cooling distribution is common for both cooling demands, namely, cooling from electricity and from heat demand
s. This results in inseparable cooling productions, reducing the flexibility of the model.

The financial analysis is carried out using a NPV analysis, considering a project lifetime of 25 years, that shows the sum of all future discounted cash flows for all the scenarios. Also, a cost analysis is made for better understanding of the costs weight. The discount rate used in this study is 6%.

For the technical analysis, results show that in order to avoid excessive NG importation (due to fuel demand peak loads) and surplus production of bio-SNG, the gasifier requires flexibility. This flexibility allows the gasifier to produce at high or low load in order to meet the restrictions above. However, for this flexibility a higher gasifier capacity is needed. A 100% replacement of NG would require more than 40,000 tons of wood chips per year, which can be unsustainable for a decentralized plant in terms of availability and delivering. The increase of the gasifier capacity reduces the exportation of electricity and increases its importation, which results in lower profits.

For the financial analysis, the results show that the NPV is negative for all the scenarios. Also, as the share of biomass increases, the NPV reduces along the scenarios, however, the reduction is not linear. Therefore, the less negative scenario is the one with 25% of biomass share. The higher the biomass share, the more negative is the NPV. This is due to the increase of gasification capacity for the needed flexibility. The cost analysis can help in demonstrate better the non-linear increase of the costs with the increase of the biomass share as well as the weight of each type of cost. Biomass costs are the highest ones with more than 50% of weight in the total costs. Comparing the two cases, they share similar NPV for the first three scenarios. For the last scenario, case 1 has a highly negative scenario comparatively

to case 2 with a difference about of 58%. For this study, the increase of NG price due to the decrease of the plant NG demand is not assessed. Also, the economy of scale is not considered for the gasification equipment, the prices are considered linear, only dependent of the gasification capacity.

Also, a NPV sensitivity analysis is carried out, showing that the feasibility of this type of project is strongly dependent on the NG and biomass prices. Some variations in those prices, for instance a reduction of more than 30% in the biomass price or an increase of more than 20% in the NG price, would result in scenarios with positive NPV, namely 50%Bio and 75%Bio for both cases. The efficiency of the gasification is analysed also, it shows that the efficiency strongly influences the outcome of the NPV analysis, however the variation is very limited by the range that the value can take. On the contrary, CO_2 emissions costs does not influence much the results because the current price on emissions is very low, 5.35€/ton. Since the prices were higher in the past, the NPV is calculated with a price of 26.86€/ton, an average peak price occurred in June 2008. The results show that the NPV became less negative and that the 50%Bio1 and 50%Bio2 scenarios even had a NPV of approximately 0.9 M€ (case 2 slightly higher) and a PB period of approximately 25 years.

This type of project is not economically feasible in Portugal for the considerations proposed. However, funds and incentives are not taken into account. With the increasing pressure of decarbonizing the EU, more funds and incentives should be addressed for renewable power generation. Also, the EU is going to revise the EU ETS market for the years 2021-2030 reducing the overall number of emission allowances over the years [50]. This can contribute to the financial feasibility of this type of projects. As seen, a higher price on CO_2 emissions could turn the NPV positive for the 50% scenario, that would be responsible for a 50% reduction of CO_2 emissions.

5.2. FUTURE WORK

To face the issue of the bioenergy sustainability it is important to study the integration of more RES regarding the objectives of a SES. Since the study is focused in a decentralized plant and the place where it is constructed is limited, some RES can be discarded like off-shore wind and wave energy. Also, since the space is limited, the gasification plant sizes of the high biomass share scenarios must be assessed in order to see the feasibility of the project regarding space availability. So, further work should focus in the inclusion of solar photovoltaic and urban wind turbines to produce electricity with the aim of balancing the electricity grid and, if feasible, to produce heat through heat pumps.

Also, there are some European countries like Germany [51], where it is possible to sell biomethane to the NG grid. In Portugal that is not yet possible. However, studies were carried out by the Portuguese Laboratório Nacional de Energia e Geologia regarding the potential assessment of the biomethane impact in Portugal [52], which fixes the cost of production with injection on the grid in 46 €/MWh. Also, the Portuguese company Rede Eléctrica Nacional developed a study regarding the technical issues of

injecting the biomethane into the NG grid [53]. With this conjecture in mind, it would be interesting to study the technical and financial feasibility of this type of project with the possibility of injecting the produced gas into the NG grid. For instance, a real-time optimization tool could be developed that integrates the NG prices fluctuation and the bio-SNG production price. For example, if at a specific time, the NG import price is lower than the production price of bio-SNG, the system would import NG and sell the bio-SNG produced to the grid. This would increase the penetration of the biomass gasification, and, although the plant would be consuming NG, at the same time it would contribute to the reduction of CO_2 emissions by providing a greener gas to the NG grid.

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