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Bio-LNG and CO_2 liquefaction investment for a biomethane plant with an output of 350 Nm^3/h

A techno-economic-environmental analysis

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Preface

I would especially like to thank my lovely wife Sihui that have get to bear a much greater role in taking care of everything during my course of study since I also have a fulltime job, in addition to these fulltime studies. And a special thanks to my two wonderful children Johannes and Josefin for having accepted that I have sometimes been occupied with the studies. I would also like to thank all the personnel at the Institute of Biogas, Waste Management and Energy, Especially Prof. Dr.-Ing. Frank Scholwin who gave the idea for the topic of the thesis and M.Sc. Friedrich Brandes for being my supervisor with all that entails. I would also like to thank my colleagues (the engine department crew) on the Well Stimulation vessel Island Patriot who have supported me during these studies. Also, thanks to my supervisor, professors, teachers and classmates at the University of Gävle.

Abstract

Stricter requirements from the European Union and the German government regarding the utilization of renewable and sustainable fuels for transportation, power, and heat production are currently in effect. This has led to that heavy transportation companies are looking for a more sustainable alternative to liquefied natural gas, such as liquefied biomethane. The monetary costs for the release of greenhouse gas are also increasing due to the carbon certificates that are being traded are decreasing in numbers each year. Carbon certificates grant companies an allowance of releasing a certain amount of emissions without being fined. Carbon dioxide and biomethane liquefaction can be a good investment for producers of biomethane to find new markets by for example trading in carbon certificates, selling liquid carbon dioxide, and producing liquefied biomethane as an alternative transportation fuel. The sale price of biomethane is heavily dependant on the emission factor for the biomethane and as such, capturing the carbon dioxide from the biomethane plant and off-setting fossil carbon dioxide would increase the sale price of the biomethane.

The methods used are theoretical and quantitative, Numerical data was collected to be able to perform the economical and environmental calculations. The investment cost for the liquefaction technologies was scaled down to correspond to a plant with a production capacity of 350 Nm^3/h. Also included in this thesis is a review of biomethane production, together with theory for the economical and environmental calculations.

By performing a technical, economical and environmental assessment of the technologies for the liquefaction of carbon dioxide and biomethane. This thesis shows that liquefaction of biomethane is not an economical viable option at the moment for plants equal or below this production capacity, due to a negative net present value, negative return on investment, sensitivity to fluctuating costs, and a high payback time. However, it could help in achieving the sustainability goals set forth by the European Union and the German government. With regards to the liquefaction of carbon dioxide it is deemed a viable investment option with an investment cost of approximately 1 million Euro and a payback time of approximately 3 years. Liquefaction of carbon dioxide could bring an extra income to the biomethane plant. This due to an added revenue in the sales of liquid carbon dioxide and an increase in the sale price of biomethane due to a reduction of the emission factor from 17 $g_{CO2\text{-}eq}$ /MJ to -23 $g_{CO2\text{-}eq}$ /MJ. The investment could also help achieving the sustainability goals by decreasing the dependence on fossil carbon dioxide for various sectors.

Keywords: Biomethane liquefaction, Carbon dioxide liquefaction, Biogas upgrading, Liquefaction economy, Biomethane life cycle assessment, Biomethane greenhouse gas saving potential, Biomethane emission factor.

Nomenclature

Abbreviations and acronyms

LCA	Life Cycle Assessment
CO_2	Carbon dioxide
LCO_2	Liquefied carbon dioxide
BLNG	Bio liquefied natural gas
LNG	Liquefied natural gas
RED II	Renewable energy directive II
GHG	Greenhouse gas
H-gas	Higher heating value gas
L-gas	Lower heating value gas
NH_3	Ammonia
CH_4	Methane
N_2O	Dinitrogen oxide
N_2	Nitrogen
He	Helium
LPG	Liquefied petroleum gas
CHP	Combined heating and power
ORC	Organic Rankine cycle
CF	Cash flow
PV	Present value
NPV	Net present value
ROI	Return on investment
LCC	Life cycle cost
LC	Levelized cost
Nm^3/h	Gas flow at normal conditions (20˚C and 101.325 kPa)
Mtoe	Million ton of oil equivalent

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1 Introduction

1.1 Background

The production of biomethane is increasing at a faster rate at the present time and at the same time heavy transports utilizing Liquefied Natural Gas (LNG) as fuel are increasing and looking for more sustainable alternatives [1]. This can be due to greater environmental awareness and the Renewable Energy Directive II (RED II) [2]. RED II in accordance with the Paris agreement have set climate goals of a reduction of emission by at least 40% of 1990 levels by the year 2030. To achieve this goal renewable fuels utilized for the production of heat, electricity, and for transportation is a way to move forward and also reach sustainability. The European Union total percentage of renewable energy sources should be at least 34% by the year 2030 according to RED II. Other measures than renewable fuels should be taken by the member states to reach the total goal, for example improved energy efficiency and various incentives like carbon certificates. The European Union have an emission trading system were industry and companies are obliged to trade in emission certificates. These certificates will decrease in number each year and as such the price will increase. Germany has more stringent requirements since 2021 that also includes the heating and transportation sector and will in-cooperate a gradual increase in the price for every ton of CO_2 released [3]. The price will increase to 55 Euro/t to the year 2025 and to 65 Euro/t to the year 2026, followed by a price set by the supply and demand with a decreasing number of certificates as in the European Unions emission trading system. Since the prices of biomethane is connected to the Greenhouse Gas (GHG) saving potential achieved at the production plant [1] and since the transport sector are searching for sustainable alternatives, investing in Carbon Capture and Reuse (CCR) technologies and the liquefaction of biomethane to Bio-LNG (BLNG) could possibly be a good investment both for the environment and for the economy of biomethane plants. Therefore, this thesis will present an economical, technical and environmental assessment of these two investment options, liquefaction of CO_2 and liquefaction of biomethane. In addition, a short review will be given regarding biogas production and upgrading, this due to readers of this thesis in other fields may not be acquainted with the production of biomethane. The topic of this thesis was suggested by Prof. Dr.-Ing. Frank Scholwin at the Institute of Biogas, Waste Management and Energy in Weimar, Germany during a meeting with the author. This meeting was initiated due to the author was seeking to develop more knowledge regarding biogas technologies and engineering.

1.1.1 Biogas plant description

The suggested biomethane plant [1] [4] [5] consist of two pair of biogas reactors (digesters) that is utilizing mostly energy crops and a relatively small amount of manure as feedstock. The total amount of feedstock the year 2019 [5] for the two pair of digesters can be seen in Table 1 below.

Table 1: Feedstock total amounts to the digester during the year 2019.

Feedstock	Quantity [t]
Cattle manure	1921
Manure inc. rest feedstock	1000
Horse manure	48
Swine manure	26058
Dry chicken droppings	7000
Straw	387
Maize silage	37841
Grass silage	837
Whole plant silage	8917
Grain	84
Potatoes (field product)	421

The two pair of digesters are connected in parallel. The biogas from the digesters is lead to a chemical scrubber (upgrading plant) were the Carbon Dioxide (CO_2) and other impurities get separated from the methane (CH_4). As shown in Figure 1 below the upgraded biogas (biomethane) is then treated and lead into the German transportation gas grid as a higher heating value gas (H-gas). A rest product from the digesters is the digestate that is later utilized as fertilizer by regional farmers. The rest product from the upgrading plant is an off-gas that mainly consist of CO_2. The plant has three combined heating and power (CHP) plants that consist of three gas engines where one of them also have an Organic-Rankine Cycle in-cooperated to it to increase the waste heat utilization. The CHP plants is utilizing the produced biogas that is not upgraded to biomethane as fuel for heating and power production. The produced electricity is sold to the electricity grid and a portion of the electricity is utilized in the different processes at the biomethane plant. The produced heat is utilized in the processes and for district heating.

The plant also has a boiler utilizing biogas as fuel, it is in service if the biogas needs to be evacuated. The heat produced in this boiler can be utilized as district heating and to supply heat to the processes involved in the production of biogas and biomethane. In Figure 1 below a flowchart of the biomethane plant can be seen.

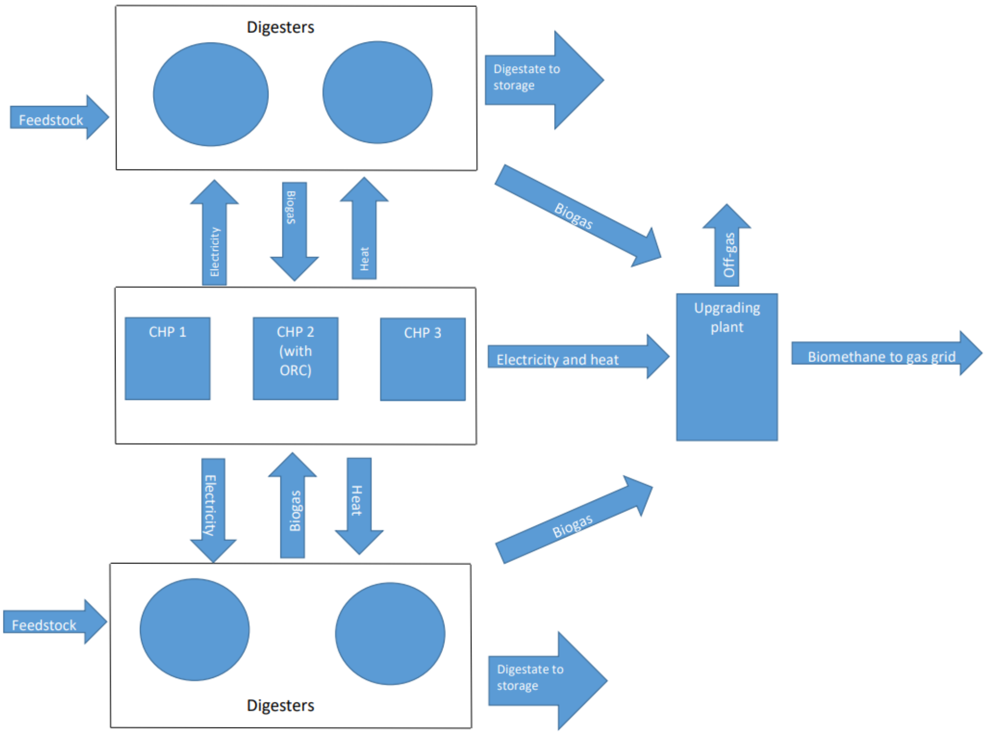

Figure 1: Flow chart of biomethane plant.

1.2 Literature review

To attain information regarding biogas, CO_2 and biomethane liquefaction, different databases were utilized in the search. The databases used were *Google, Google Scholar, Science Direct, Energiforsk* and the *University of Gavle's library web function*. The search words were *Liquefaction, CO_2, Biogas upgrading, Biomethane, Biomethane LCA*. To find different suppliers and manufacturers of the systems involved for the purpose of CO_2 and biomethane liquefaction, *Google* were used with similar search words. The Renewable Energy Directive II were found searching the *European commissions database*. Scientific articles with economical and environmental assessments regarding small scale liquefaction of biomethane and CO_2 were difficult to find. Most articles give a general description of the processes and later investigate how to improve the efficiency or the modelling of new theoretical processes.

For the liquefaction of biomethane F. Capra et al. [6] and K. Spoof-Tuomi [7] are both describing different processes and evaluating them economically. F. Capra et al. [6] performs a technical and economical evaluation of different technological processes involved in the liquefaction of biomethane and LNG. They further present their findings on five of these technologies, they are (1) the reversed Brayton cycle, (2) reversed Rankine cycle, (3) Claude cycle, (4) reversed Stirling cycle and (5) the liquid nitrogen vaporization cycle. The study on those different technologies was conducted by simulating and optimize the different processes in Aspen Plus, a simulation and optimisation program. These simulations are performed on a small-scale plant with the production of 4.6 t_{BLNG}/day and the conclusion they reach are that the most cost-effective process is the reversed Rankine cycle with mixed refrigerants with a levelized cost of 315 Euro/t (conversion made by author). The highest levelized cost however is for the process utilizing the Stirling process with a levelized cost of 704 Euro/t (conversion made by author) However for all the performed calculations, the cost of the biomethane that is feed into the liquefaction plant is disregarded. They also conclude that due to a high price of liquid nitrogen and the amount needed for plants with an output of over 4 t_{BLNG}/day, the liquid nitrogen vaporization cycle is not a viable option. A techno-economic report by K. Spoof-Tuomi at the University of Vaasa [7] arrives at similar conclusions for a plant with an output of 5 t/day. In this report the process of the reversed Brayton cycle, Linde cycle, reversed Rankine cycle, reversed Stirling cycle and liquid vaporization is described and reference is made to existing plants utilizing these technologies. He concluded that an investment cost for a 5.0 t_{BLNG} /day plant is in the range of 0.75 million Euro to 2.7 million Euro with a net present value of 1.7 million Euro to 6.0 million Euro during a 20-year lifetime and a discount rate of 5 %. The levelized cost for the most attractive plant, which is a process utilizing the reversed Rankine cycle, is calculated to 144 Euro/t_{BLNG} and for liquid vaporization that is the most expensive option with a levelized cost of 342 Euro/t_{BLNG}. With regards to the liquefaction of CO_2, it was even more difficult to find scientific literature covering economical and environmental calculations for small scale plants that is utilizing CO_2 produced by biomethane plants. The articles mostly cover large scale carbon capture and storage evaluations. L.E. Øi et al. [8] describes different processes for the liquefaction of CO_2 such as the external and internal refrigeration processes. They also investigate the economical aspects of CO_2 liquefaction plants with an off-gas input of 125 t/h utilizing the simulation program Aspen HSYS and conclude that the investment cost for a standard external refrigeration process is 22.3 million Euro with a levelized cost of 4 Euro/t_{LCO2}. For a internal refrigeration process the investment cost was estimated to be 26.3 million Euro with a levelized cost of 4.13 Euro/t_{LCO2}.

A master thesis from the Royal Institute of Technology in Sweden by M-S. Svanberg Frisinger [9] investigate the technological and economical aspects of small scale (45 t_{LCO2}/h) CO_2 liquefaction with the simulation and optimisation program Aspen Plus. The thesis was assessing a plant with and without heat pumps for the utilization of waste heat for district heating. She conclude that the levelized liquefaction cost of a internal refrigeration system is 17.42 Euro/t_{LCO2} and for a external liquefaction system 17.75 Euro/t_{LCO2}.

Regarding the GHG calculations Gustafsson and Svensson [10] performed a comperative environmental and economical assessment of bio-LNG and LNG for heavy transports. They conclude that the GHG saving potential are 45% to 70% for BLNG utilized in transportation and manure as the feedstock. And when utilizing food waste as a feedstock between 50% to 75%. Calculating with the utilization of the digestate as fertilizer, the GHG saving potential taking both feedstock in account, are between 80% and 125%. The values vary greatly depending on if the calculations are carried out according to RED II or the ISO standard for LCA. They further conclude that due to the high production costs of BLNG it will be difficult to compete with LNG.

1.3 Aims

The aim of this thesis is to investigate the economical feasibility of investing in biomethane and CO_2 liquefaction for a biomethane plant with a specific biomethane output of 350 Nm^3/h [1]. An overview of the liquefaction processes and uses of the end products will be described as well. The change in GHG saving potential should also be investigated since this have a great effect on the sale price of the biomethane and the bio-LNG. Side aims of this thesis is to increase the knowledge of biogas production, upgrading, liquefaction and GHG calculations of biomethane for the author and other readers.

1.4 Approach

The approach utilized in this thesis were to collect numerical data of the biomethane plant and for the two investments. Also, technical reports and scientific literature were collected and studied with regards to biomethane production, CO_2 liquefaction, biomethane liquefaction, and GHG calculations.

2 Theory

2.1 Biogas and biomethane production review

2.1.1 Feedstocks

Agricultural, household, industry, and forestry wastes containing high amounts of protein, starch, sugar and fats are excellent feedstock for anaerobic digesters since they are easily decomposed [11]. The different feedstocks or biomasses have different yields, they can produce a different amount of methane (CH_4) during the digestion process depending on their composition. Agricultural feedstocks are for example animal manure, slurries, residual crops, and in the case of growing biomass for the production of energy, energy crops. Industrial wastes include for example wastes from the food industry, forestry wastes include for example residues from the pulp and paper industry. Household wasted include for example food wastes and other organic wastes that have been properly sorted, also sewage from households can be utilized as a feedstock. Manure by itself is not a very effective feedstock but mixing it with crops will increase the CH_4 yield. There is also CH_4 yield boosters such as fish oils from the fishing industry and wastes containing alcohol from the brewing industry. These are however only added in relatively small quantities. The feedstock is an important design parameter for the digesters since the different feedstocks have different characteristics for optimal biogas production.

2.1.2 Pre-treatment

Feedstocks need sometimes to be treated before entering the digester. There could be impurities mixed in the feedstock that would affect the performance of the digester in a negative way [12]. Separation can be needed to remove foreign objects that could block the flow or damage the following pre-treatment steps and agitators in the digester. The feedstocks could also need to be shredded to smaller pieces or cut open to increase the surface area for the bacteria in the digester. Some of the pre-treatment options can be for example thermal pre-treatment. It is carried out to break the hydrogen bonds in the feedstock and make the feedstock more easily digestible and also to stop the feedstock from swelling in the digester. Swelling of the feedstock occurs due to hemicellulose and this can be a problem for the digester [11], it can cause blockages etc. Chemical pre-treatment of the feedstock can also be carried out to prevent swelling, it is however not widely utilized in the biogas industry due to the relatively high cost of chemicals [13].

2.1.3 Digester

In anaerobic digesters, feedstock with a high amount of water and small amount of fibrous and inorganic material is preferred for an optional biogas yield. There are also aerobic digesters that is more suitable for feedstock that have the opposite characteristics just mentioned [11]. The rest of this section will focus on anaerobic digesters and it will only be mentioned as digester in this report. In the digester different microbes and bacteria are working on the feedstocks in four different reactions, these reactions occur in the digester simultaneous. In hydrolysis the bacteria are breaking down the organic material in to smaller and more easily digestive pieces such as sugar, fatty and amino acids. Fermentation or acidogenesis as it is also called occurs by splitting the previously mentioned easily digestive pieces to hydrogen, short chain fatty acids, CO_2, alcohols and acetate in a reaction called dehydrogenation combined with acidogenesis. All the products of these different reactions react together in a final reaction that is called methanation to form the biogas [14]. The digesters can be divided in three different temperature classes. The lower temperature class holds a temperature of 10-25˚C and is called psychrophilic digestion. The slightly higher temperature range of 25-45 ˚C is called mesophilic digestion and the class with the highest temperature of 50-80 ˚C is called thermophilic digestion [12]. Different bacteria multiply and interact better with the feedstock at different temperatures and the methane producing bacteria for thermophilic digestion is the most sensitive to temperature deviations [14].

2.1.4 Upgrading

The produced biogas needs to be cleaned and upgraded to biomethane before it can be injected to the gas grid, this to increase the Wobbe index [MJ/m^3] of the gas. The Wobbe index is showing the proportion between the specific gravity and the heating value of a gas used for combustion, as such it provides an indication on, if different gases can be utilized in the same equipment. The biogas only contains between 40 to 75 % CH_4 depending on the feedstock and digestive processes involved, the rest of the volume are contaminants of various kind. CO_2 take up the greatest amount in the biogas of the all the contaminants with roughly 25-55 %. Other contaminants are hydrogen sulphide, ammonia, water, nitrogen and hydrogen. Some of the contaminants causes corrosion problems in the pipeline or at the end consumers and they lower the heating value of the biomethane [15]. The off-gas or waste product from the upgrader is mostly CO_2 that is released to the atmosphere, normally a regenerative thermal oxidation unit is utilized to oxidise the CH_4 in the off-gas if the off-gas contain more than 1% CH_4. The cleaning of the biogas is performed to remove water, ammonia and hydrogen sulphide before the biogas is compressed for upgrading [16]. There are several ways to clean and upgrade the biogas, such as pressure swing absorption, chemical scrubbing, water scrubbing, membrane separation and cryo-technologies. In the pressure swing absorption process the biogas is compressed and sent through different materials such as activated carbon and zeolites, different gases are attracted to different material. The rule is that the higher the pressure the better the different contaminants get absorbed to said materials. When the material is fully absorbed by the contaminant the pressure is released and the contaminant for example CO_2 will detach itself from the material. Absorption units are often placed in several parallel connected units to achieve a continuous flow of gas during regeneration [15]. Membrane separation technologies take advantage of the fact that the different gases are of different sizes on a molecular level. The biogas is here also compressed and pushed through the membrane that only will let the contaminants pass through it and retain the CH_4 in and guide it out [16]. Water scrubbing and chemical scrubbing (amine washing and organic physical scrubbing) works in a similar way. The water or the amine is flowing against the direction of the biogas and the water or amine solution absorbs the CO_2 from the biogas and let the CH_4 continue on its path. For the water to absorb the CO_2 the pressure of the gas should be high since the higher the pressure the more CO_2 will be absorbed. The absorbent is regenerated by suddenly lowering the pressure or by heating it, sometimes both regeneration types is combined. Regarding amine scrubbers the amine solution absorbs more CO_2 than water and as such a smaller amount of fluid and smaller dimensions of the upgrading plant can be utilized. Also, the amine solution only needs to be heated to regenerate [17], the plant in this thesis is utilizing an amino scrubber with a production of over 99% pure biomethane [5]. Cryo-technologies for biogas upgrading can produce both liquefied biomethane and liquefied CO_2 in the same upgrading plant. There are two main processes involved, the anti-sublimation process and the cryogenic distillation process. In the anti-sublimation process the CO_2 is frosted out from the biogas in a solid form and later separately exposed to heat to change the phase to liquid [18]. In the cryogenic sublimation process the temperature is controlled much more carefully to avoid the solidification of the CO_2 and extract it in a liquid form directly. More information regarding cryogenic upgrading of biogas can be found in Spitoni et al. (2019) [19] and Naquash et al. (2022) [20]. Before the biomethane is injected into the grid the pressure needs to be increased and an additive is added to the biomethane to give an olfactory warning of possible leakages [17]. It may also be needed to increase the Wobbe index of the biomethane further, if the gas is injected to a H-gas grid. This by adding liquefied petroleum gas (LPG) for example propane to the biomethane before injecting it to the gas grid. In case of the biomethane being added to a L-gas grid it could be required to lower the Wobbe index, this is usually done by adding air to the biomethane [11].

2.2 Economical calculations

The economical calculations [21] utilized in this thesis are firstly calculating the simple payback time (equation 1) presented below,

$$Payback\ time[Years] = \frac{I\ [Euro]}{R\left[\frac{Euro}{year}\right] - \left(C_1\left[\frac{Euro}{year}\right] + C_2\left[\frac{Euro}{year}\right] + C_3\left[\frac{Euro}{year}\right]\right)} \qquad (1)$$

I is the investment cost in Euro, R is the annual revenue in Euro, C_1 is the annual electricity cost in Euro, C_2 is the annual maintenance cost also in Euro and C_3 is the cost of the biomethane in Euro. This calculation does not take the time value of money in consideration as can be seen by the raw data in appendix A when comparing it with the cumulative present value. The next calculation is the net present value and it takes the time value of money in consideration with a yearly interest rate or discount rate, also a yearly increase in the electricity price is in-cooperated. However firstly a yearly cash flow (CF) is calculated according to equation 2 below.

$$CF_n[Euro] = R_n[Euro] - (C_{2n}[Euro] + C_{3n}[Euro] + (C_{1n}[Euro] \cdot (1 + \frac{A[\%]}{100}))^n \qquad (2)$$

R is the revenue for the specific year in Euro, C_2 is the maintenance cost for the specific year n in Euro, C_3 is the cost of biomethane for the specific year, C_1 is the electricity cost for the specific year in Euro, A is the annual increase of the electricity cost in percent and n is the specific year. For year zero the cash flow is equal the investment cost, the same apply to the present value (PV) and the cumulative value or net present value (NPV). The following equation (3) calculates the PV of the cash flow,

$$PV_n[Euro] = \frac{CF_n[Euro]}{\left(1 + \frac{r[\%]}{100}\right)^n} \qquad (3)$$

were r is the discount rate in percent and the other factors are same as mentioned above. The cumulative value of the investment is the same as the NPV, it is calculated by starting at n zero (0) adding up all the following PV's until reaching the expected lifetime of the investment. To calculate the return on investment (ROI) the NPV is divided by the investment cost as presented in equation 4,

$$ROI[\%] = \frac{NPV[Euro]}{I[Euro]} \cdot 100 \qquad (4)$$

For this report the next to be calculated was the life cycle cost (LCC) and it can be seen in equation 5 below. This was done by adding up all the costs, taking the expected lifetime n[Years] and the yearly increase of the electricity price A [%] into consideration. However, it does not take the time value of money in consideration.

$$LCC[Euro] = I[Euro] + \left(C_1[Euro] \cdot \left(1 + \frac{A[\%]}{100}\right)\right)^n + (C_2[Euro] \cdot n) + (C_3[Euro] \cdot n) \tag{5}$$

Where I is the investment cost in Euro, C_1 is the annual electricity cost in Euro, C_2 is the annual maintenance cost in Euro, C_3 the annual cost of biomethane in Euro. Lastly the levelized cost (LC) was calculated, it is the cost for producing one mass unit of the end product. In equation 6 below the mass unit is kg.

$$LC\left[\frac{Euro}{kg}\right] = \frac{LCC[Euro]}{P\left[\frac{kg}{year}\right] \cdot n[Years]} \tag{6}$$

Here P is the annual production output in kg per year, LCC is the life cycle cost in Euro previously calculated in equation 5 above and n is the expected lifetime in years.

2.3 Greenhouse gas emission calculations

The calculations for the GHG emissions and the GHG saving potential of the biomethane are carried out in accordance to RED II [2] and with the guidelines formulated by The German Biomass Research Centre [22].The GHG considered for these calculations should be carbon dioxide (CO_2), dinitrogen monoxide (N_2O) and methane (CH_4). They do need to be converted to CO_2 equivalents (eq) were CO_2 have a value of 1, N_2O have a value of 298 and finally CH_4 have a value of 25. That means for example that 1 kg of CH_4 is equal to 25 kg CO_2-eq. When different feedstock is mixed in a digester, equation 7 below should be utilized to calculate the actual emissions.

$$E = \sum_1^n S_n \cdot (e_{ec,n} + e_{td,feedstock,n} + e_{l,n} - e_{sca,n}) + e_p + e_{td,product} + e_u - e_{ccs} - e_{ccr} \tag{7}$$

The total emission from the production of the biomethane is E [$g_{CO2\text{-}eq}$/MJ], the fractional total share of the feedstock is S_n, emissions during cultivation is $e_{ec,n}$, $e_{td,feedstock,n}$ is the emissions during transportation of the feedstock and $e_{l,n}$ is regarding the annualized emissions actualized by land use change by carbon stock change for feedstock n. When manure is utilized in the digester the CH_4 is not released into the atmosphere but is instead taken care of in the digester, due to this there is a bonus (manure credit) of 45 g CO_2-eq/MJ_{manure} rewarded in the calculations. The manure bonus can be seen as e_{sca} since it deals with improved agricultural management. The emissions from the processing is e_p, where the production of other products should be taken into account as well, this is a so-called allocation, that the emissions are counted to the right product. From the transportation of the biomethane $e_{td,product}$ the emissions created by for example keeping the pressure in the transport pipeline etc, should be included. The biomethane during it use as a fuel is e_u and e_{ccs} and e_{ccr}

are carbon captured and storage (CCS) and carbon captured and replaced (CCR). For calculating e_n equation 8 is utilized,

$$e_{ec,p,td,u}[\frac{kg_{CO2-eq}}{kg}] = \frac{\sum Input\ material[kg] \cdot Emission\ factor[\frac{kg_{CO2-eq}}{kg}]}{Amount\ of intermediate\ product[kg]} \tag{8}$$

When calculating e_{ec} different emissions need to be taken in consideration such as from cultivation, extraction and emission leakage of raw materials. To calculate e_{td} it is important to consider that the truck might drive empty when it is picking up the feedstock, thus adding this in the calculations with a different emission factor. For calculating $e_{l,n}$ equation 9 below must be utilized and there are also other things that need to be taken in consideration, for example the emissions need to be equally distributed over a 20-year period, this due to the soil organic carbon reach equilibrium at this point [23]

$$e_{l,n} = (CR_R - CR_A) \cdot 3.664 \cdot \frac{1}{20} \cdot \frac{1}{P} - e_B \tag{9}$$

Where CR_R is the reference land, mass of carbon per area were both vegetation and soil are considered. CR_A is the actual land, mass of carbon stock per area. The bonus e_B is to be taken in consideration when the cultivated land has not been in use as farmland before first of January 2008. Also, the land must have been severely degraded, for example been eroded or salinized if including former farmland. To be able to consider e_{ccr} there must be evidence of the carbon being captured from the transportation, extraction, distribution or process of biomethane, biogas and the feedstocks and it must be stored in geological formations. With e_{ccr} there must be evidence of carbon being captured from the transport, extraction, distribution or processing of biomethane, biogas or the feedstocks and it must also be proven that the carbon that is captured are utilized to replace fossil carbon. To calculate the greenhouse gas saving potential a fuel comparator $E_{comperator}$ is utilized. The fuel comparator has different values depending on if the fuel is consumed as a transportation fuel, a fuel for the production of electricity and as a fuel for producing heat. The fuel comparator for transportation is 94 g_{CO2-eq} /MJ_{fuel}, for electricity production 183 g_{CO2-eq} /MJ_{fuel} and for heat production 80 g_{CO2-eq} /MJ_{fuel} [2]. The GHG saving potential is then calculated according to equation 10 below.

$$GHG\ saving\ potential\ [\%] = \frac{E_{Comperator} - E_{Product}}{E_{Comperator}} \cdot 100 \tag{10}$$

3 Method

The research methods utilized in this report are theoretical and quantitative. The theoretical method involved studying literature on biogas production, biogas upgrading and liquefaction technologies. The quantitative method regards the collection of data from scientific reports and interviews. The abstracts were read from several scientific articles and the articles that seemed most relevant to this case, mentioning a general description of the systems and environmental or economical data were read through thoroughly. The numerical data for the biomethane plant, biomethane, and CO_2 liquefaction plants were given during interviews with personnel at the Institute for Biogas, Waste Management and Energy. This data constitutes of numbers for the economical calculations such as investment costs, electricity consumption and data such as capacities and production flows among other. However, the data collected with regards to the liquefaction plants are not designed for the specific biomethane plant investigated in this report (biomethane output of 350 Nm^3/h). Actual measurements at the biomethane plant were not carried out due to time constrains and the COVID-19 situation. Most data for the energy consumptions and feedstock quantity are from 2019, regarding the biogas into the upgrading plant and biomethane out from the upgrading plant a mean value is utilized with data from the years 2018 and 2019. The upgrading plants electrical consumption was calculated with a specific consumption of 0.14 kWh/m^3 [16] The economical calculations were carried out in Excel in accordance to the previously described methodology in chapter 2.2 in this report. To perform the calculations, information regarding biogas upgrading had to be acquired and studied. This to be sure that the right assumptions are being made, this since the quality of the off-gas and the biomethane need to be within certain limits (depends on liquefaction technology) and the be able to assume a specific electrical consumption. Also, a general review of biogas production had to be carried out for the environmental calculations to get a better understanding of the processes involved. Mathematical estimations had to be made by scaling the data attained to fit the plant in question. This were done by calculating conversion factors for the two liquefaction plants. For example, the CO_2 liquefaction plant´s conversion factor was calculated by dividing the amount of liquid CO_2 (LCO_2) produced with the amount of off-gas flowing in to the LCO_2 plant. This conversion factor was later utilized to calculate this specific plant´s possible LCO_2 production output, by multiplying the conversion factor with the output of off-gas from the biogas upgrading plant. The off-gas was calculated as the difference in the biogas into the upgrading unit and the biomethane out from the upgrading unit. The same procedure as for the LCO_2 were carried out for the biomethane liquefaction plant except the output of biomethane was utilized and divided by the output of BLNG.

A specific investment cost was calculated by dividing the investment cost with the production output and this was interpolated for the biomethane liquefaction plant and extrapolated for the LCO_2 plant to match the output's of the plant sizes in this report. This were also carried out to the cost options and the specific electricity consumption for the LCO_2 plant. For the liquid biomethane (BLNG) plant the specific electrical consumption was deemed to be relatively similar among the manufacturers and sizes after studying the literature and the data given during the interviews. In view of that, the specific electrical consumption utilized are from a BLNG plant with a production capacity of 25 t/day. The electrical consumptions are at nominal capacity and can as such be seen as a yearly average. Regarding options for the BLNG plant it was included in the price for the greater output plant and an assumed cost of 200 000 Euro were added to the smaller output plant since options were not included in the obtained investment cost. With the specific costs and consumptions, the investment cost and electricity consumption for the plant in this report could be calculated. It should be mentioned that since the plant is producing its own electricity and are utilizing it in the processes in conjunction to selling the surplus electricity to the electrical grid, it can be seen as a loss of income to supply the investments with electricity depending on the current tariffs and sale prices. As such the electricity price is in-cooperated in the economical calculations. Raw data for the scaling and for the biogas upgrading plant can be seen in the screenshots from the calculations from Excel in appendix B. In Figure 2 below the calculated specific investment cost for the CO_2 liquefaction plant together with the data collected is presented. On the y-axis the specific investment cost in Euro t^{-1} day^{-1} can be seen and on the x-axis the plant output in t/day is presented. It can be seen that the cost for a plant with an output of 42 t_{LCO2}/day have a specific investment cost of 32 143 Euro t^{-1} day^{-1} [5]. A plant with an output of 16.8 t_{LCO2}/day have a specific investment cost of 65 923 Euro t^{-1} day^{-1} [4] and the extrapolated specific investment cost for a plant with an output of 12.8 t_{LCO2}/day is 80 858 Euro t^{-1} day^{-1}.

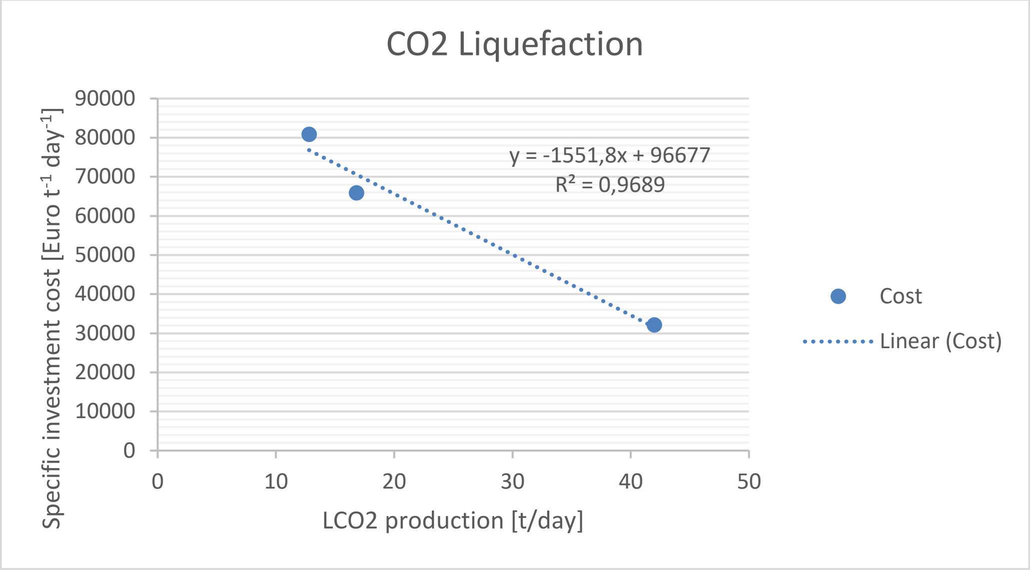

Figure 2: LCO2 specific investment price.

The costs for the LCO_2 plants are based on the Rankine cycle [4] although different refrigerants are utilized. The smaller of the plants (700 kg_{LCO2}/h) is utilizing CO_2 as a refrigerant and the plant with an output of 1750 kg_{LCO2}/h is utilizing Ammonia (NH_3) as a refrigerant. In Figure 3 below the specific investment cost in Euro t^{-1} day^{-1} can be seen on the y-axis for the liquefaction of biomethane. On the x-axis the plant biomethane output is presented in t/day. The greater of the plants have an output of 25 t/day and a specific investment cost of 306 520 Euro t^{-1} day^{-1} [5]. The smaller of the plants have an output of 3.4 t/day and a specific investment cost of 470 588 Euro t^{-1} day^{-1} [4]. For the plant size in this report the output is 6.7 t/day and the specific investment cost is calculated to 445 728 Euro t^{-1} day^{-1}.

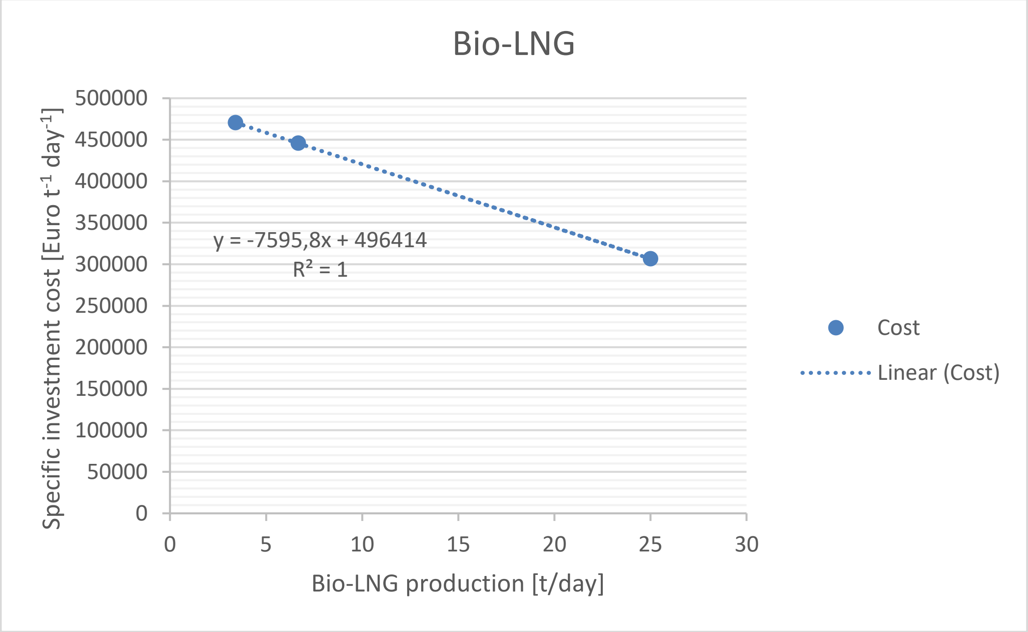

Figure 3: Biomethane liquefaction (Bio-LNG) specific investment cost.

Technologies for BLNG plants are based on different processes, the plant with the larger output is based on the reversed Brayton cycle and the plant with the smaller output is based on the reversed Stirling cycle. Assumptions made for the economical calculations are that the yearly discount rate is 5 %, the lifetime is 10 years, operating time of a year is 95 % and the yearly maintenance cost is 3 % of the investment cost with options (storage tank, filling station etc.) included. There is also a steady increase of the electricity cost of 2 % per year. The electricity cost (0.163 Euro/kWh), the sale price of LCO_2 (0.13 Euro/kg), the cost of biomethane (0.66 Euro/Nm^3) and the sale price of Bio-LNG (1.18 Euro/kg) are values from the end of the year 2021 and the beginning of the year 2022 [4]. Costs for permits and other miscellaneous and overhead cost are disregarded in this report as well as possible rest values. For the LCO_2 calculations the cost of biomethane is not included since the off-gas is currently a waste gas. Sensitivity analysis for the options is made by changing the investment cost, electricity price, biomethane cost, sale price of LCO_2 and Bio-LNG and the discount rates with different percentages. The raw data for the economical calculations can be seen in the screenshots from Excel in appendix A.

The environmental calculations were carried out in Excel according to chapter 2.3 in this report and it can be seen as a cradle-to-gate life cycle assessment (LCA). Where the functional unit is 1 MJ of biomethane, and the gate is either the biomethane leaving the upgrading unit or the liquefaction unit. When the information was gathered and compiled the calculations started by adding together the input [5] of feedstock from the two biogas reactors. They were as such treated as one digester for the calculations made. The methane yield [24] for the different feedstocks were utilized to be able to calculate the percentage share of the yield for the different feedstocks. Some assumptions and simplifications were made to perform the LCA calculations. The simplifications made are that all the feedstock that is plant based are calculated as maize silage with regards to the input data and emission factors of said data [22] for the cultivation emissions. This due to time constrains on the deadline for this report and that the cultivation emissions are assumed by the author to be relatively comparable between different plant-based feedstocks. Another simplification made is that the transport distance for all the feedstock are the same. Finally, this report has disregarded e_l, $e_{td, product}$, e_u and e_{ccs} this due to lack of data, time constrains, or it was not applicable in this case. Since electricity is produced by gas engines running on biogas the electricity and heat emission factors for the consumption of electricity and heat for all the plants are based on such a case [25]. Also, the conditioning of the biomethane to H-gas is disregard in this report.

Sensitivity analysis made on the LCA were done by changing the emission factors for the feedstocks firstly according to a LCA study [26] from Denmark and secondly with typical values from the Renewable energy directive II [2]. The electrical and heat emission factors were also changed to see how the biomethane emission factors would change. This due to, depending on the tariffs it could be more profitable to buy electricity from the grid. The electricity emission factor was changed to were the electricity is produced in a CHP plant burning straw (0.00571 $kg_{CO2\text{-}eq}/MJ$) [25], a emission factor were the electricity is produced by natural gas (0.12442 $kg_{CO2\text{-}eq}/MJ$) [25], the EU electricity mix 2016 (0.1063 $kg_{CO2\text{-}eq}/MJ$), and heat produced from woodchips (0.00043 $kg_{CO2\text{-}eq}/MJ$) were used in the calculations [25]. The manure credit was also removed to see its effect on the calculations. The sensitivity analysis was made on the total emission for the biomethane without investments and with the liquefaction of CO_2 investment, the liquefaction of biomethane was left out. Raw data for the GHG calculations can be seen in appendix C in the form of screenshots from the authors calculations in Excel. In all appendices it is clearly stated the source of the data and when it is the authors own calculations based on the stated data.

4 Results

4.1 Liquefaction

4.1.1 Biomethane liquefaction

4.1.1.1 Process description

To liquefy biomethane the temperature needs to come down to cryogenic levels under -161 ˚C, the boiling point for CH_4 at atmospheric pressure [27]. There are in principle a few different technologies for the liquefaction of biomethane and they follow the same principles as for liquefying natural gas to LNG. For smaller scale liquefaction there is for example the reversed Brayton cycle, the Rankine cycle with mixed refrigerants, the Linde cycle, reversed Stirling cycle and Cryogenic liquid vaporization [7] [28] [29]. The reversed Brayton cycle is utilizing a pure refrigerant sometimes in a cascade process. The refrigerant can for example be Nitrogen (N_2) or the biomethane itself and it is compressed and expanded in one or several stages to reach the low temperature needed for liquefaction to take place. After the compression and expansion of the refrigerant, the refrigerant and the biomethane is flowing in to one or several heat exchangers where the heat transfer occurs. The expansion of the refrigerant is carried out in turbines and as such the energy taken out from the turbines is supplied to the compressors to improve the efficiency. Figure 4 below shows a simplified version of the reversed Brayton process.

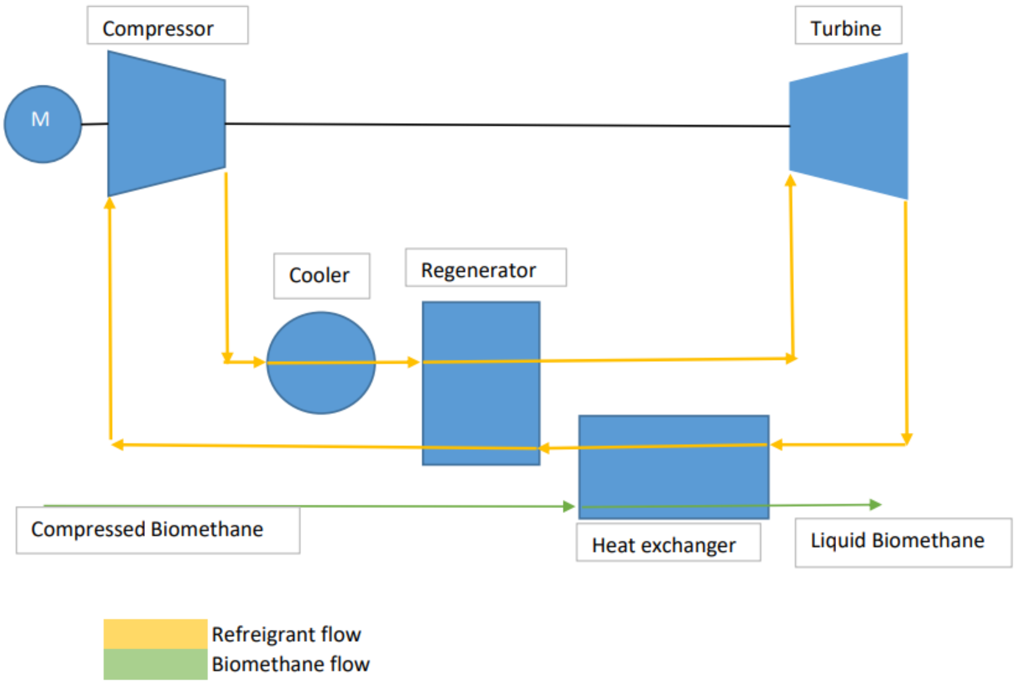

Figure 4: Basic reversed Brayton process with regeneration, modified from [6].

The reversed Rankine cycle that uses mixed refrigerants is particularly effective at purifying the biomethane as it liquefies. This due to the so-called refrigerant glide, different refrigerants have different boiling points. As such the boiling points can be matched between the refrigerant and the contaminants. The mixed refrigerant is compressed, cooled, condensed and expanded via a Joule-Thompson valve before it is evaporated. In a single mix refrigerant system that is more suitable for smaller scale operations the heat transfer occurs in a cryogenic heat exchanger. Figure 5 below show a simplified version of the reversed Rankine cycle.

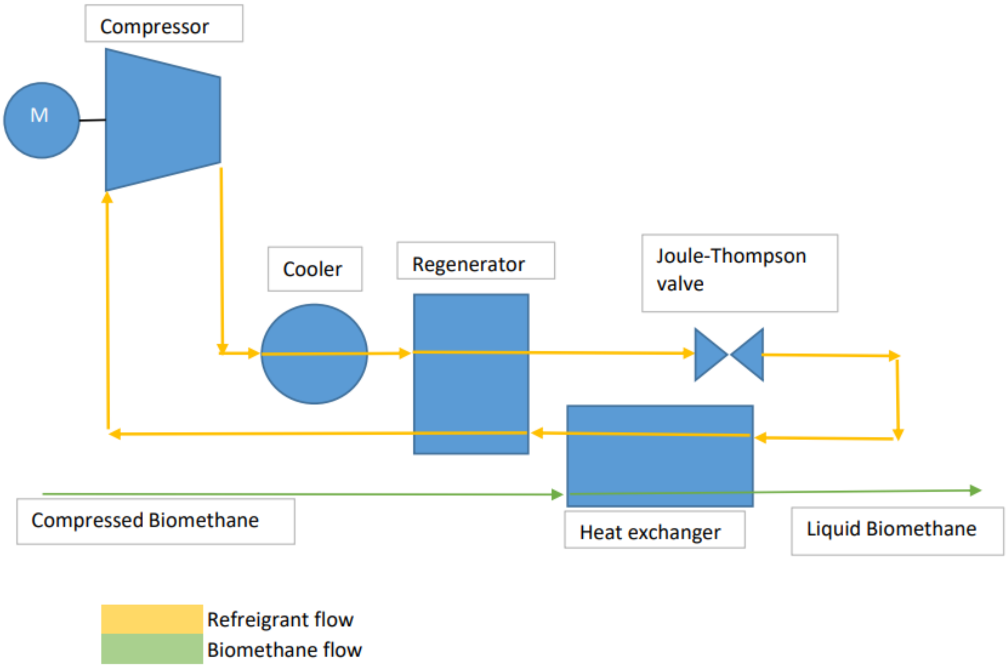

Figure 5: Basic reversed Rankine cycle with regeneration, modified from [6].

The Linde cycle works in a similar way as the mix refrigerant cycle but the biomethane itself is utilized as a refrigerant. The biomethane is compressed, cooled and passes a regenerator unit. It is then expanded in a Joule-Thompson valve and flows to a separator that separate the remaining gaseous biomethane from the liquid part. The gaseous part is then lead through the regenerator unit and the liquefied biomethane is lead to storage [6] [7]. Figure 6 below shows a simplified version of the Linde cycle.

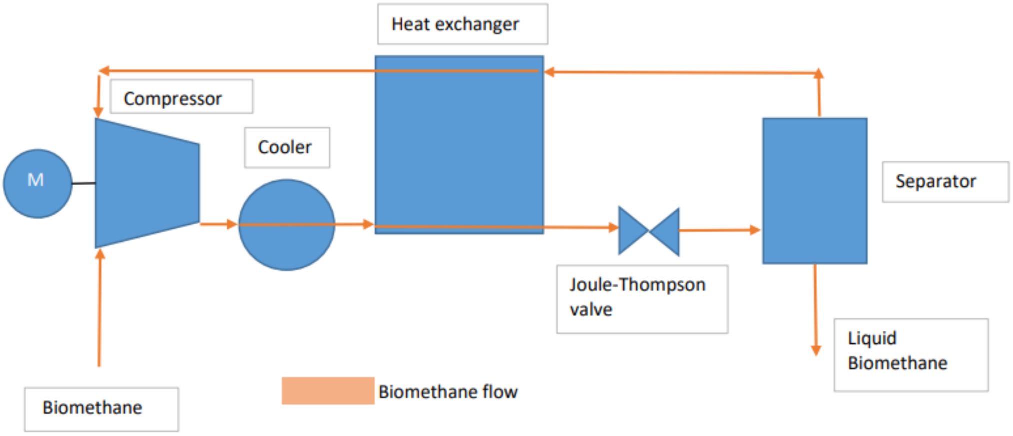

Figure 6: Basic Linde cycle, modified from [6].

The reversed Stirling cycle uses a piston compressor to compress and expand Helium (He). The biomethane is purified and led through the compressor without any physical contact with the Helium. The He is compressed, cooled, expanded and displaced in the compressor [30] [31]. The expansion occurs when the piston moves to its lower position and the biomethane will transfer heat to the He though the condenser head. After the expansion the He is displaced and a compression stage begins. The heat from the compression stage is removed by a regenerator that the He must pass before the compression starts. Figure 7 below shows a simplified version of the reversed Stirling cycle.

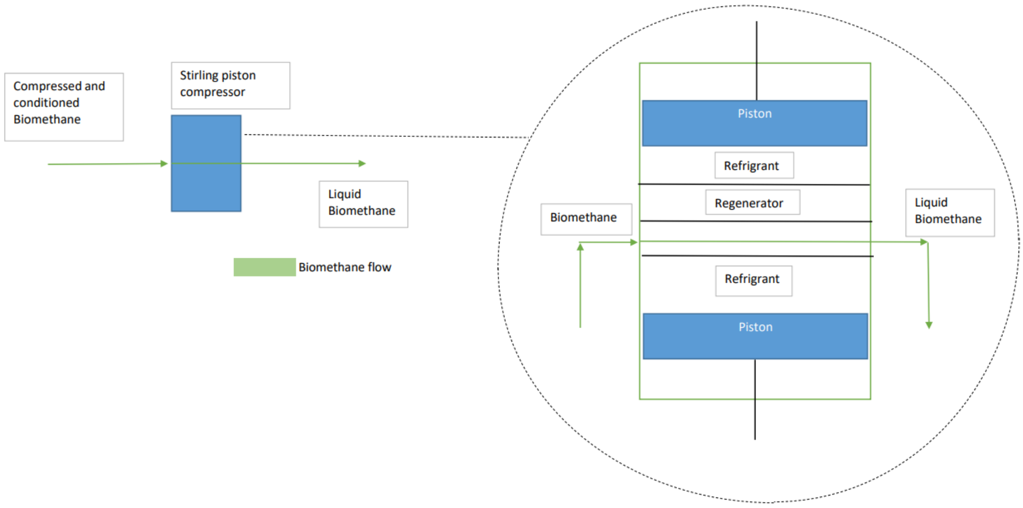

Figure 7: Simplified reversed Stirling process flow, modified from [6].

Cryogenic liquid vaporization uses liquid N_2 to liquefy the biomethane. This is done by letting the biomethane transfer heat to the liquid N_2 in a heat exchanger [6]. This is often a once through process, meaning that the liquid N_2 is evaporated just once and then released in the atmosphere. Figure 8 below show the process flows of the liquid vaporization process.

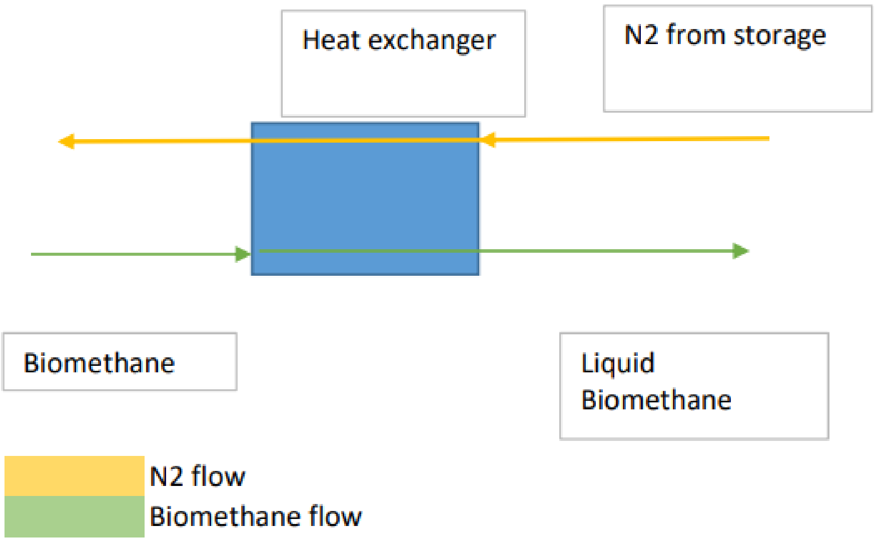

Figure 8: Basic process flow of liquid vaporization. Made by author in Excel, modified from [6].

4.1.1.2 Suppliers

One experienced supplier of liquefaction plants for the biomethane and LNG market is Air Liquide [32]. According to the suppliers they have experience in the reversed Brayton cycle, mix refrigerant cycle and cryogenic technologies for various purposes and gas treatments. One supplier of the reversed Stirling technology is Stirling cryogenics together with HSYSTECH [30]. They are experienced in various fields in the cryo-technology segment. There are also other suppliers such as Cryo Pur who supplies biogas upgrading and biomethane liquefaction technologies [33].

4.1.1.3 Applications of Bio-LNG

Liquid CH_4 have a much higher energy density than CH_4 in gas form at normal conditions. Since the energy density is around 600 times higher [34] in liquid form and around 2 to 3 times higher than compressed CH_4 gas [6] it is a very attractive form for storing and transporting energy. Since bio-LNG is a much more environmentally friendly and sustainable fuel than fossil LNG it can be of great use in the transportation sector to reduce emissions. Specifically heavy transports such as the shipping industry and trucking. The forest industry and the agricultural industry also have heavy equipment that could be converted to running on bio-LNG instead of compressed natural gas and diesel [35].

4.1.2 CO_2 liquefaction

4.1.2.1 Process description

The technologies are relatively similar to the liquefaction of biomethane, however the temperature at which CO_2 will liquefy is much higher. The boiling point and as such the liquefaction temperature of CO_2 at normal conditions is -78.5 ˚C [36]. In general, two different principles of liquefaction are most widely utilized, they are internal refrigeration and external refrigeration, however the CO_2 gas is often compressed to a higher pressure to increase the liquefaction temperature and reduce the cooling requirement. In internal refrigeration the CO_2 itself is compressed and expanded through one or several stages with Joule-Thompson valves or turbines, this to lower the temperature and liquefy the CO_2 [37]. A simplified model of an internal refrigeration process is shown in Figure 9 below.

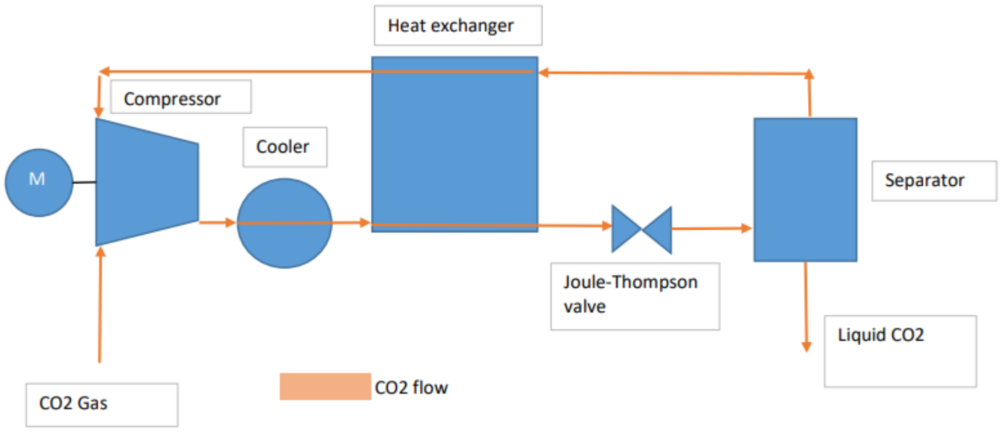

Figure 9: Basic internal refrigeration process, modified from [6] [37].

The Linde Hampson cycle is an example of an internal refrigeration principle, that compresses the CO_2 in several steps before letting it expand through a Joule Thompson valve. The External refrigeration uses other refrigerants such as Ammonia (NH_2) or CO_2 (R774) in a separate Rankine cycle to liquefy the CO_2 gas with the help of heat exchangers [8]. A simplified version of the external refrigeration process is shown in Figure 10.

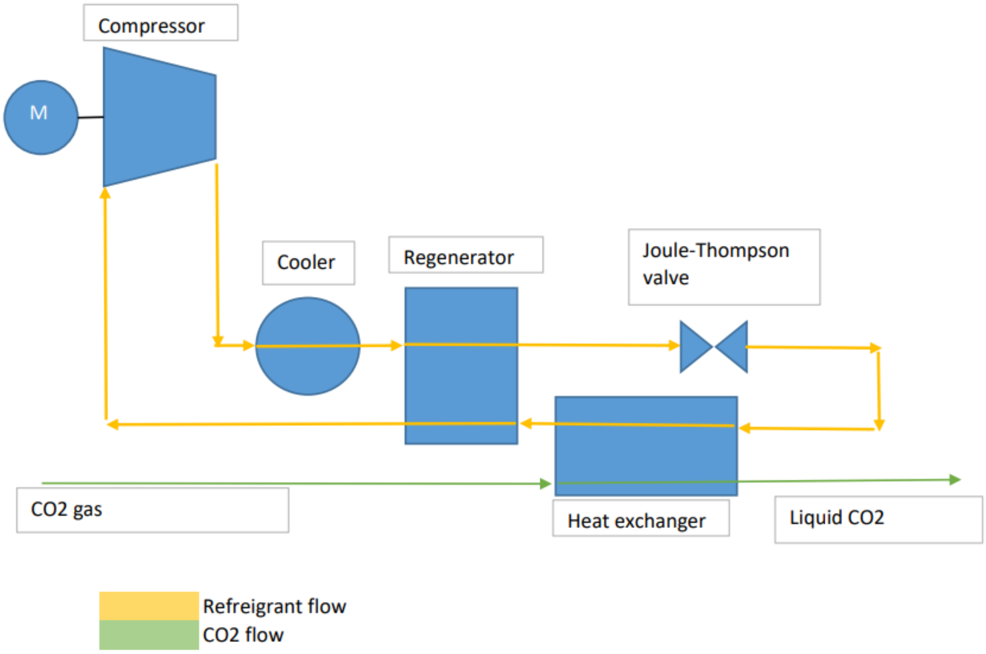

Figure 10: Basic external refrigeration process, modified from [6] [37].

4.1.2.2 Suppliers

For the supply of CO_2 liquefaction plants different suppliers with references were found. They are Cryotech [38], Linde engineering [39] and Bright [40]. The processes used by the suppliers is mostly the external refrigeration process, were the different suppliers use different refrigerants.

4.1.2.3 Applications of liquid CO_2

Liquid CO_2 have several applications where it would be a good substitute for fossil CO_2 [41]. The CO_2 do however need to be very pure, free of other substances for the following applications. The purity grade of CO_2 is different depending on its application [42]. The range is from 99.999% for CO_2 utilized in research down to 99.5% when it is utilized in industrial applications. Food grade CO_2 which the suppliers claim can be reached with their equipment need to be of at least 99.9% purity. Plants have an optimized growth curve at higher concentration of CO_2 in the air and as such the LCO_2 could be vaporized at the destination and utilized in greenhouses to increase the yield. In the food industry CO_2 is utilized during the production of sparkling beverages and during the packing of food products to slow down the rate of oxidation. In the cooling industry CO_2 is utilized as a refrigerant in air condition units, freezers and heat pumps and it is called R774. It can be used to produce CH_4 in what is called power-to-gas were renewable energy is utilized to produce hydrogen (H_2) by electrolysis and when H_2 reacts with CO_2, CH_4 and water (H_2O) is formed. It can also be used for the cultivation of algae that later can be utilized as a feedstock for biogas and biomethane production [43]. Other applications could be to store the CO_2 in cement blocks for constructions. This would capture the CO_2 in the construction block and at the same time increase the structural properties of the block [44] [45] [46].

4.1.3 Liquefaction of biomethane

As can be seen from Table 2 below the plant would have an annual production of approximately 2 300 ton liquefied biomethane. The electricity cost and maintenance cost were calculated to approximately 0.3 million Euro per year and 0.1 million Euro per year respectively. The cost of the biomethane was calculated to 1.9 million Euro. The investment cost for the liquefaction of biomethane was calculated to be approximately 3.0 million Euro with a simple payback time of 7.2 years. The NPV (Net present value) of the investment after a period of 10 years was calculated to be approximately 0.0 million Euro. That in turn gives a calculated ROI (return on investment) of a negative -1%. The LCC (life cycle cost) was calculated to be approximately 23.4 million Euro and a levelized cost for the production of Bio-LNG (BLNG) to approximately 1010 Euro/t. A possible annual revenue for the sales of BLNG was calculated to 2.7 million Euro.

Table 2: Calculated economical results of biomethane liquefaction.

Produced BLNG [t/year]	2 300
Electricity cost [M Euro/year]	0.3
Maintenance cost [M Euro/year]	0.09
Cost of biomethane [M Euro/year]	1.9
Investment cost [M Euro]	3.0
Payback time [Years]	7.2
Net present value [M Euro]	0.0
Return on investment [%]	-1.0
Life cycle cost [M Euro]	23.4
Levelized cost [Euro/t]	1010
Revenue for BLNG [M Euro/year]	2.7

4.1.4 Liquefaction of CO_2

Table 3 below show the economical results for the liquefaction of CO_2. The plant would produce approximately 4 400 ton of liquid CO_2. The annually electrical and maintenance cost were calculated to approximately 0.2 million Euro and 0.03 million Euro respectively. The basic payback time for liquefaction of CO_2 was calculated to 2.8 years with an investment cost of approximately 1.0 million Euro. The NPV was calculated to approximately 1.7 million Euro with a ROI of 160%. The LCC for the LCO_2 investment was calculated to be 1.6 million Euro and a levelized cost of production for the liquefaction of CO_2 is approximately 34 Euro/t. A possible annual revenue for the sales of LCO_2 was calculated to 0.6 million Euro.

Table 3: Calculated economical results for liquefaction of LCO2.

Produced LCO_2 [t/year]	4 400
Electricity cost [M Euro/year]	0.2
Maintenance cost [M Euro/year]	0.03
Investment cost [M Euro]	1.0
Payback time [Years]	2.8
Net present value [M Euro]	1.7
Return on investment [%]	160
Life cycle cost [M Euro]	1.6
Levelized cost [Euro/t]	34
Revenue for LCO2 [M Euro/year]	0.6

4.1.5 Liquefaction of biomethane and CO_2

If both investments were to be carried out at the same point in time the investment cost would be approximately 4.0 million Euro with a payback time of 5 years. The annual electricity and maintenance cost would be 0.5 million Euro and 0.1 million Euro respectively. The cost of biomethane was calculated to 1.9 million Euro. The NPV for both investments were calculated to be approximately 2.0 million Euro. The ROI was calculated to 50% and the LCC was calculated to 25 million Euro. A possible annual revenue for the sale of both products was calculated to approximately 3.3 million Euro. The above values are also presented in Table 4 below.

Table 4: Calculated economical results for CO2 and biomethane liquefaction.

Electricity cost [M Euro/year]	0.5
Maintenance cost [M Euro/year]	0.1
Cost of biomethane [M Euro/year]	1.9
Investment cost [M Euro]	4.0
Payback time [Years]	5
Net present value [M Euro]	2.0
Return on investment [%]	50
Life cycle cost [M Euro]	25
Revenue of products [M Euro/year]	3.3

4.1.6 Sensitivity analysis

The sensitivity analysis was made by changing different parameters such as electricity cost, sale price of the products, investment cost and the discount rate. Starting with the net present value (NPV) for the investments in relation to the discount rate. The NPV is presented on the y-axis in million Euro and the discount rate in percent is presented on the x-axis in Figure 11 below. It can be seen that the NPV decrease with a rising discount rate. At a discount rate of 20% the NPV for the LCO_2 investment have a NPV of 0.4 million Euro and the BLNG investment becomes zero at a discount rate of roughly 5%. The BLNG investment reach a negative value of -1.3 million Euro at a discount rate of 20%.

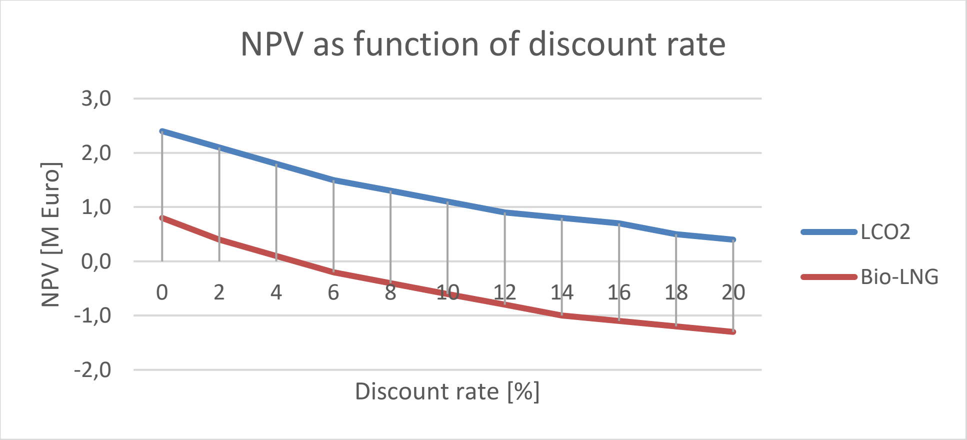

Figure 11: NPV as a function of the discount rate for LCO_2 and BLNG investments.

The electricity cost at year 0 was changed with a percentage to see how the levelized cost would change for the investments. The levelized cost in Euro/t for producing LCO_2 is presented on the y-axis and the electricity price change in percent, is presented on the x-axis. From Figure 12 below it can be seen that the levelized cost of producing liquefied CO_2 increase from 34.3 Euro/t to 35.3 Euro/t when the electricity cost increase by 25%. It can also be seen that if the electricity price is reduced by 25% the levelized cost is reduced to 33.3 Euro/t.

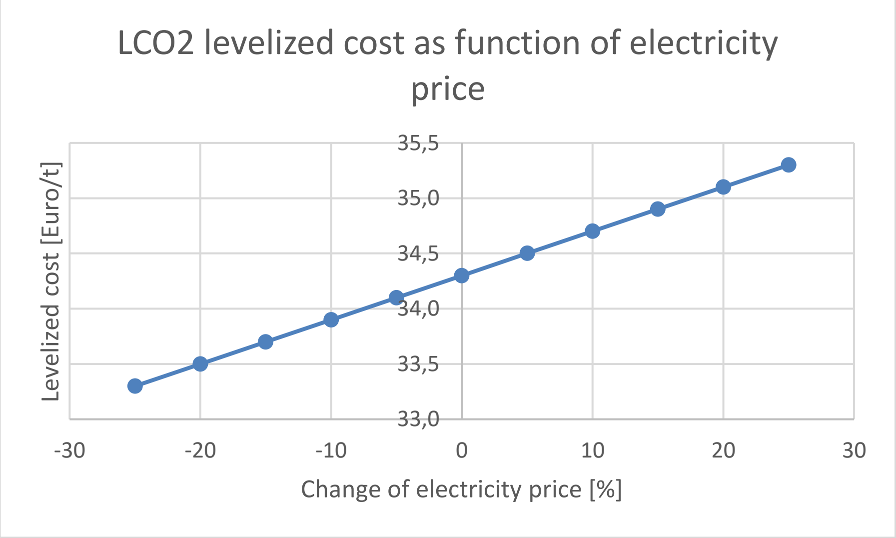

Figure 12: Levelized cost as a function of the electricity price for the liquefaction of CO_2.

Figure 13 below shows similar changes to the levelized cost as a function of the electricity price for the production of Bio-LNG. The levelized cost in Euro/t for producing BLNG is presented on the y-axis and the electricity price change in percent is presented on the x-axis. It can be seen that the levelized cost increase to approximately 1013.6 Euro/t when the electricity price is increased by 25%. However, if the electricity price decrease by 25% the levelized cost will decrease to approximately 1007 Euro/t.

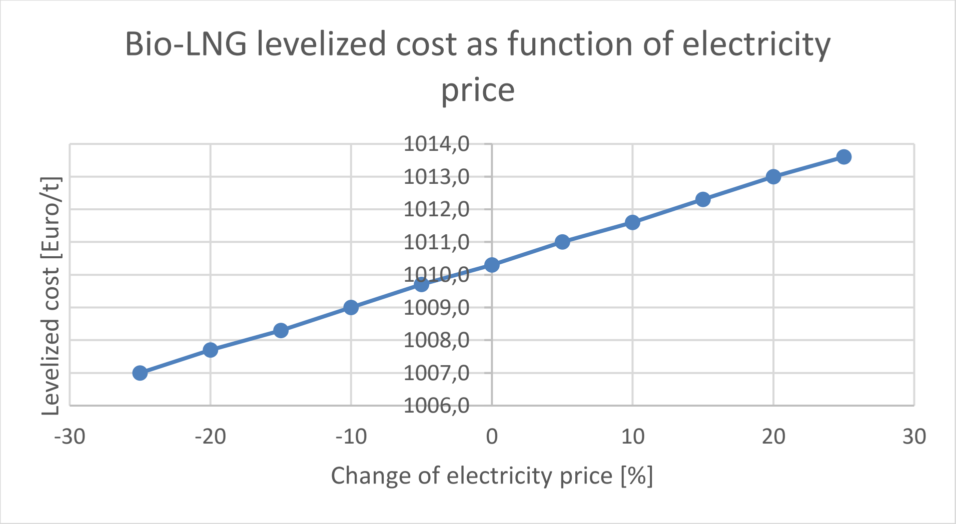

Figure 13: Levelized cost and a function of electricity price for the liquefaction of biomethane.

The NPV as a function of the sale price for the liquid CO_2 investment is presented in Figure 14 below. NPV is presented on the y-axis in million Euro and the percent change of the LCO_2 sale price is presented on the x-axis. It can be seen that if the sale price is decreased by 25% the NPV will decrease to approximately 0.5 million Euro. If the sale price is increased by 25% the NPV for this investment will increase to 2.8 million Euro.

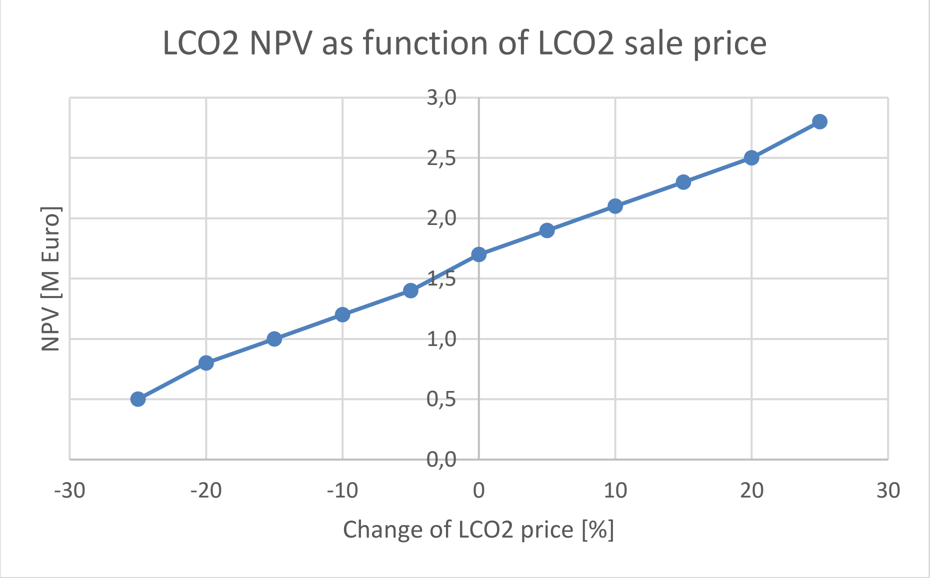

Figure 14: NPV as a function of the LCO2 sale price.

For the liquefaction of biomethane investment, it can be seen in Figure 15 with the y-axis being the NPV in million Euro and the x-axis being the percent change of the sale price for BLNG. When the sale price decrease by 25% the NPV decrease to a negative value of -5.3 million Euro. When the sale price of BLNG increase by 25% the NPV of the investment will increase to a value of 5.2 million Euro.

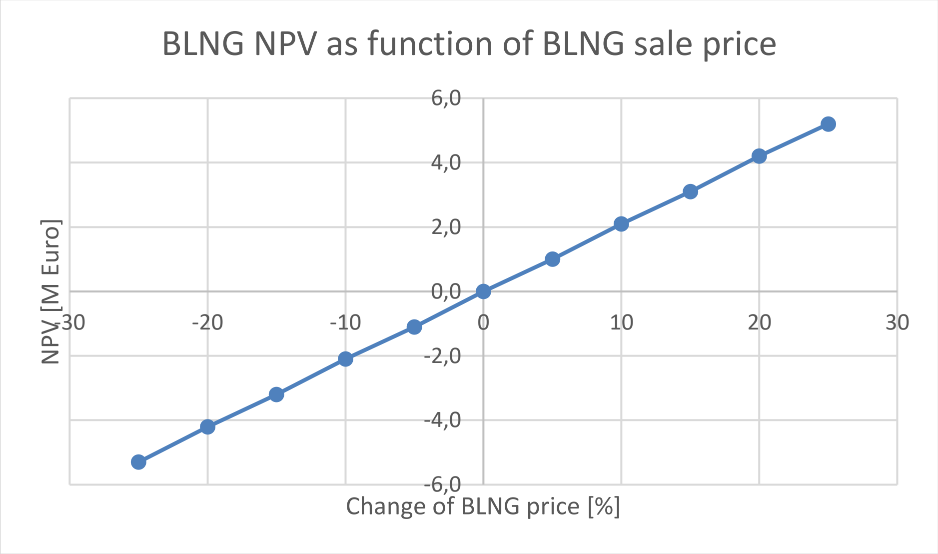

Figure 15: NPV as a function of BLNG sale price.

When decreasing the production cost for biomethane with a negative -25% the NPV will increase to a value of 3.7 million Euro for the BLNG investment. When increasing the cost of biomethane with 25% the NPV will decrease to a negative value of -3.7 million Euro, this can be seen in Figure 16 below.

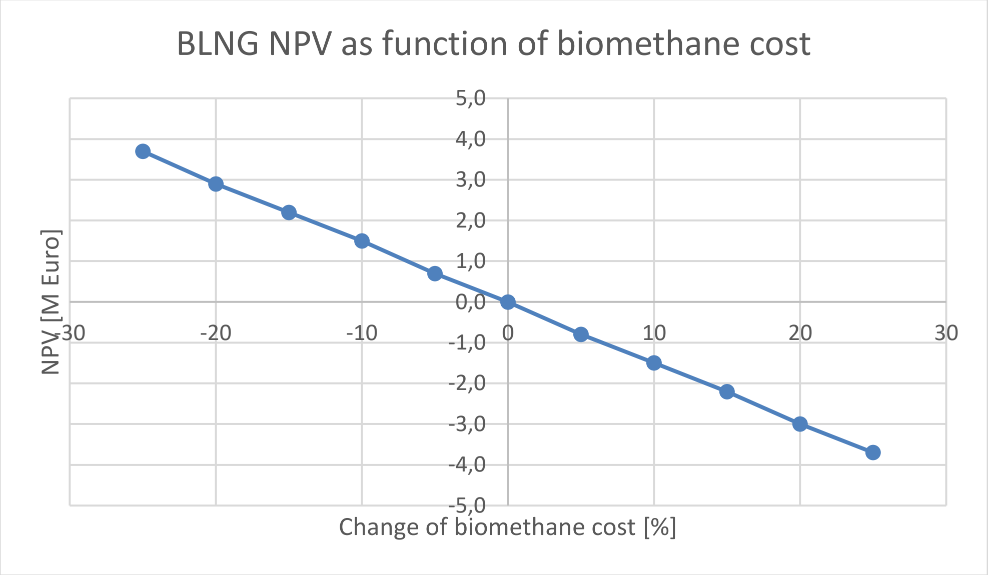

Figure 16: BLNG NPV as a function of the biomethane production cost.

Increasing or decreasing the investment cost with a percentage for the liquefaction of CO_2 and how it affects the return on investment is presented in Figure 17 below. There the ROI in percent is on the y-axis and the percent step change on the investment cost is on the x-axis. It can be seen that at a reduction of 15% of the investment cost there is an increase of the ROI to 210%. An increase of the investment cost with 15% will decrease the ROI to 123%.

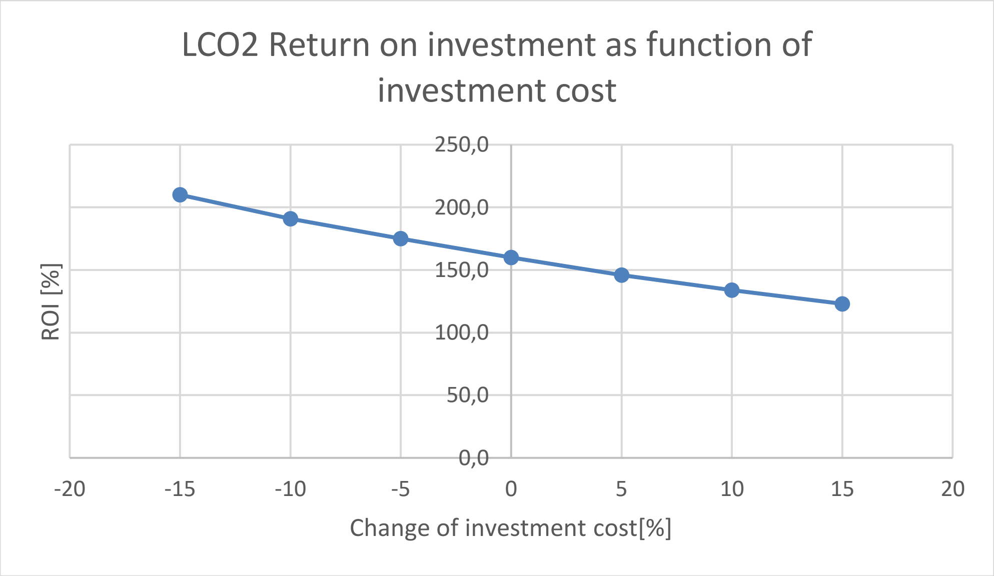

Figure 17: Liquefaction of CO2 investment cost change on ROI.

For the liquefaction of biomethane changing the same parameter as above, the results can be seen in Figure 18. There the ROI in percent is on the y-axis and the percent change of the investment cost is presented on the x-axis. It can be seen that as the investment cost decrease by -15% the ROI will increase to a value of 21%. When the investment cost is increased by 15% the ROI will decrease to a negative value of -17%.

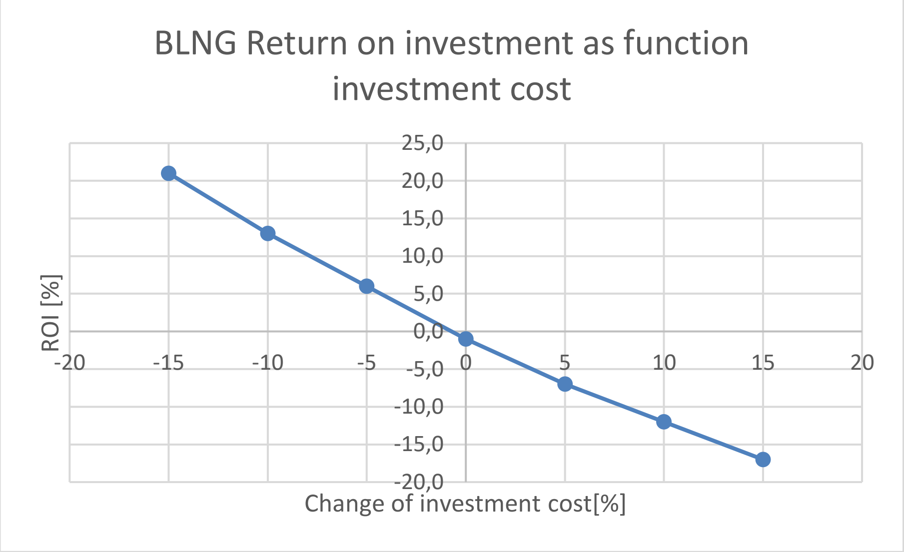

Figure 18: Liquefaction of biomethane investment cost change on ROI.

A sensitivity analysis on both investments performed at the same time is presented in Figure 19 below. The NPV in million Euro is presented on the y-axis and the change in the electricity price in percent is presented on the x-axis. It can be seen that if the electricity price decrease by 25% the NPV will increase to a value of 3.0 million Euro and if the electricity price increase with 25% the NPV will decrease to a value of 1.0 million Euro.

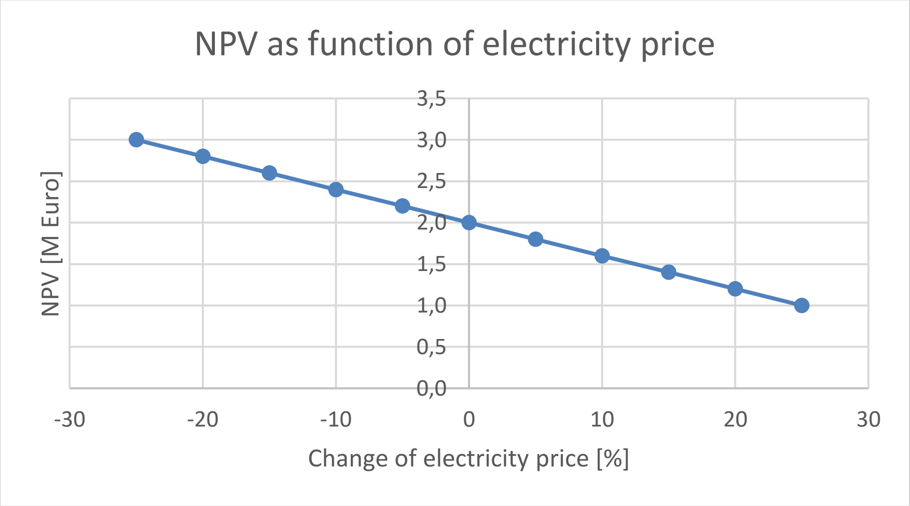

Figure 19: NPV as a function of electricity price for both investments.

Figure 20 below shows how the NPV depends on the discount rate for both investments seen as one. It can be seen that at a discount rate of 0% the NPV is 3.8 million Euro. When the discount rate increases to14% the NPV is zero. A further increase in the discount rate to 20% will reduce the NPV to a negative value of -0.7 million Euro.

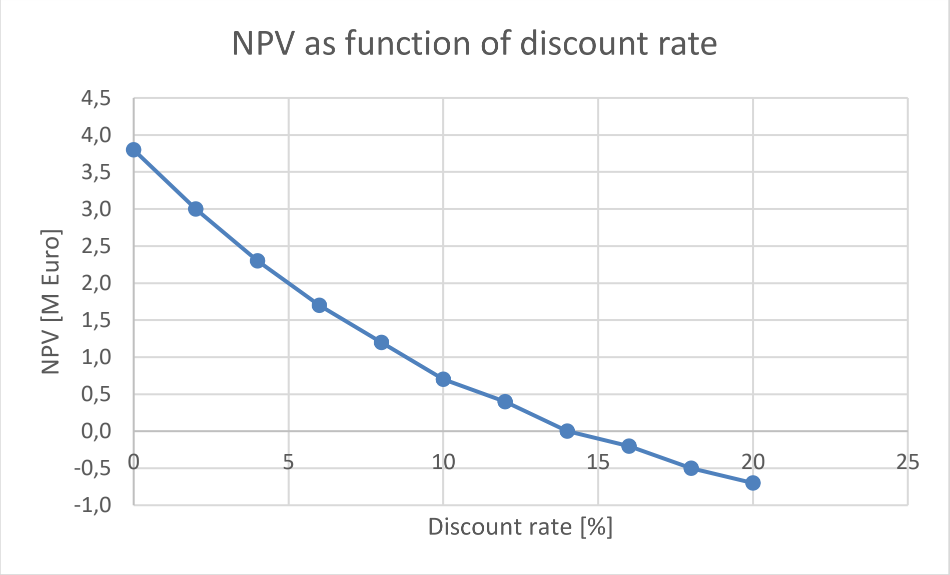

Figure 20:NPV as a function of discount rate for both investments.

When performing the same change as previously to the biomethane production cost but for the option of both investments, the NPV is increasing to a value of 5.7 million Euro at a reduction of the biomethane production cost of -25%. And when increasing the cost of biomethane production by 25% the NPV will decrease to negative value of -1.7 million Euro as can be seen in Figure 21 below.

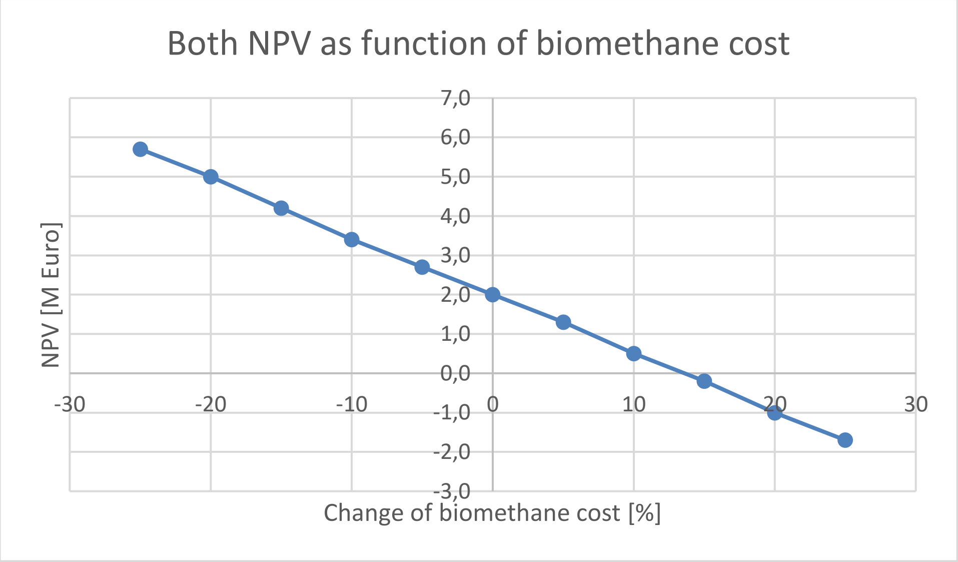

Figure 21: NPV of both investments together as a function of the biomethane production cost.

4.2 Greenhouse gas emissions

4.2.1 Without investments

The emission factor E for the biomethane was calculated to 17 $g_{CO2\text{-}eq}$ /MJ. The Greenhouse gas (GHG) saving potential of the biomethane for the plant without investment is presented in Table 5 below. It can be seen that if the biomethane is consumed as a transportation fuel the GHG saving potential is approximately 82%. If it is consumed for the production of electricity the GHG saving potential is approximately 91% and if it is consumed for heat production the GHG saving potential is approximately 79%.

Table 5: GHG saving potential for the biomethane without investments.

GHG saving potential as a transport fuel [%]	82
GHG saving potential for electricity production [%]	91
GHG saving potential for heat production [%]	79

4.2.2 Liquefaction of biomethane

If adding the investment for liquefaction of biomethane to the GHG calculations the emission factor E is calculated to 18 $g_{CO2\text{-}eq}$ /MJ. The GHG saving potential is presented in Table 6 below. There it can be seen that if the liquefied biomethane is consumed as a transportation fuel the GHG saving potential will be approximately 81%. If it is consumed for electricity production the GHG saving potential is approximately 90% and if it is consumed for heat production the potential will be approximately 77%.

Table 6: GHG saving potential for the biomethane with BLNG investment.

GHG saving potential as a transportation fuel [%]	81
GHG saving potential as an electricity production fuel [%]	90
GHG saving potential as a heat production fuel [%]	77

4.2.3 Liquefaction of CO_2

If calculating only with the liquefaction of CO_2 investment the emission factor E is negative at -23 $g_{CO2\text{-}eq}$ /MJ. In Table 7 below the GHG saving potential is presented, it can be seen that if the biomethane is consumed as a transportation fuel the potential saving is approximately 124%. If it is consumed for electricity production the GHG saving potential is 150% and if consumed for the production of heat the potential is 190%.

Table 7: GHG saving potential for Biomethane with the LCO2 investment.

GHG saving potential as a transportation fuel [%]	124
GHG saving potential as an electricity production fuel [%]	150
GHG saving potential as a heat production fuel [%]	190

4.2.4 Liquefaction of biomethane and CO_2

If both investments are combined E is calculated to a negative -21 $g_{CO2\text{-}eq}$ /MJ. The GHG saving potential for the different usages of the fuel is presented in Table 8 below and it can be seen that if the fuel is consumed for transportation, the GHG saving potential is 123%. If the fuel is consumed for electrical production the GHG saving potential is 112% and if consumed for the production of heat the potential is 127%.

Table 8: GHG saving potential for Biomethane with both investments.

GHG saving potential as a transportation fuel [%]	123
GHG saving potential as an electricity production fuel [%]	112
GHG saving potential as a heat production fuel [%]	127

4.2.5 Sensitivity analysis

The sensitivity analysis was made on the emission factor E for the biomethane without investments and with the LCO_2 investment calculating with emission factors from an LCA study [26] and typical emission factors from the Renewable Energy Directive II (RED II) [2]. Also, the manure credit was removed and the emission factors for heat and electricity were changed to other emission factors such as electricity produced from natural gas and EU electricity mix 2016 for example. It can be seen in Table 9 that E without investments is 15 $g_{CO2\text{-}eq}$/MJ and with the added investment of liquefaction of CO2 a negative -25 $g_{CO2\text{-}eq}$/MJ with the emission factors from the LCA study.

Table 9: Emission factor for the biomethane calculated with emission factors from a LCA study.

E [$g_{CO2\text{-}eq}$/MJ]	15
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-25

In Table 10 below E calculated with typical emission factors from RED II is presented, it can be seen that without investments E is again 15 $g_{CO2\text{-}eq}$/MJ and with the LCO_2 investment a negative -25 $g_{CO2\text{-}eq}$/MJ.

Table 10: Emission factor for the biomethane calculated with emission factors from RED II.

E [$g_{CO2\text{-}eq}$/MJ]	15
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-25

Table 11 presents the emission factors for the biomethane when removing the manure credit for the GHG calculations. Without the LCO_2 investment E would be 21 $g_{CO2\text{-}eq}$/MJ. With the LCO_2 investment the emission factor E would be -19 $g_{CO2\text{-}eq}$/MJ.

Table 11: Emission factor without manure credit for biomethane with and without LCO2 investment.

E [$g_{CO2\text{-}eq}$/MJ]	21
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-19

If the biomethane plant would get its electricity from a combined heat and power plant with straw as fuel, the emission factor E would be 16 $g_{CO2\text{-}eq}$/MJ. If the LCO_2 investment would be added to this case, E would be -24 $g_{CO2\text{-}eq}$/MJ as can be seen in Table 12 below.

Table 12: Biomethane emission factors with electricity produced from a CHP plant burning straw.

E [$g_{CO2\text{-}eq}$/MJ]	16
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-24

In Table 13 below the emission factor E with and without the LCO_2 investment is presented. E is 24 $g_{CO2\text{-}eq}$/MJ without the investment and -12 $g_{CO2\text{-}eq}$/MJ with the LCO_2 investment.

Table 13:Biomethane emission factors with electricity produced from natural gas.

E [$g_{CO2\text{-}eq}$/MJ]	24
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-12

When changing the emission factor for electricity from biogas to EU electricity mix 2016 the calculated emission factors are 23 $g_{CO2\text{-}eq}$/MJ without the investment and minus 14 $g_{CO2\text{-}eq}$/MJ with the investment, as can be seen in Table 14 below.

Table 14: Biomethane emission factors, EU electricity mix 2016.

E [$g_{CO2\text{-}eq}$/MJ]	23
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-14

In Table 15 below the emission factor for heat have been changed to one with heat being produced by burning woodchips. It can be seen that without the investment the calculated emission factor E is 17 $g_{CO2\text{-}eq}$/MJ and with the LCO_2 investment -23 $g_{CO2\text{-}eq}$/MJ.

Table 15: Biomethane emission factors, heat produced from burning woodchips.

E [$g_{CO2\text{-}eq}$/MJ]	17
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-23

Combining the EU electricity mix 2016 and the heat production from woodchips emission factors. The calculated emission factors for the biomethane are 23 $g_{CO2\text{-}eq}$/MJ without investment and -14 $g_{CO2\text{-}eq}$/MJ with the investment. This is presented in Table 16 below.

Table 16:Emission factors for biomethane, EU electricity mix 2016 and heat from woodchips.

E [$g_{CO2\text{-}eq}$/MJ]	23
E [$g_{CO2\text{-}eq}$/MJ] (with LCO_2 investment)	-14

4.3 Energy consumptions

In Table 17 below, the electricity demand and the annual electricity consumption for the liquefaction of biomethane and CO_2 at nominal capacity is presented. The annual energy consumptions were calculated to be 1.9 GWh for the biomethane liquefaction plant at 225 kW and 1.1 GWh for the CO_2 liquefaction plant at 131 kW.

Table 17: Electricity demand and consumptions at nominal capacity.

Electricity demand BLNG plant [kW]	225
BLNG plant annual electricity consumption [GWh]	1.9
Electricity demand LCO_2 plant [kW]	131
LCO_2 plant annual electricity consumption [GWh]	1.1

5 Discussion

The economical, technical, and environmental investigation of the CO_2 and biomethane liquefaction investments have been fulfilled by calculating the economical and environmental values of the two investments. The technical description of the two options together with the biogas and biogas upgrading review have fulfilled the side aims of this thesis. The results are showing that it is a viable investment option to invest in the liquefaction of CO_2 and it was expected after studying the literature and concluding that since the off-gas is a waste, it can be calculated as a resource without a cost. Regarding the liquefaction of biomethane the author did not have any expectation since the knowledge of the processes involved were relatively unknown at the time. However, the literature studied seemed to point to the fact that small scale liquefaction of biomethane is not an economical viable option, as the results of this thesis also will conclude. If this option should be interesting the investment cost need to decrease with roughly 50% or the sale price of BLNG must increase with a similar percentage, this to come closer to be able to safely handle fluctuations in different costs. Another option to make the BLNG investment more resilient could be a reduction of the production cost of the biomethane. Also, using absorption chillers to reduce the electrical costs could be an option [47]. The simplifications made could probably affect the result to a certain point, but it is doubtful the results would change very much. Regarding the technical review of the liquefaction processes it was difficult to find scientific journals explaining the processes specifically for biomethane and CO_2 from upgrading plants. Most literature found dealt with the liquefaction of natural gas and scrubbing CO_2 of combustion exhaust gases, such as Song et al. (2019) [48] and Jackson & Brodal [49]. There seem to be a lack of research being made on small scale biomethane liquefaction and in view of this the author think that this thesis could also help fill that gap to some extent. The data gathered for the biomethane liquefaction were based on two different processes (reversed Brayton cycle and reversed Stirling cycle) and as such the economical results for the biomethane liquefaction plant can be seen as an average, covering the different processes available. This due to the studied literature name the same technologies utilized for this thesis calculations, as the best and worst economical solution, with a range of other processes in between. With that said the results of this thesis are in the higher range than the literature regarding the levelized cost at 1010 Euro/t_{BLNG}. This is most likely due to that the cost of biomethane production is disregarded in the literature where in this thesis it is not. If disregarding the cost of the biomethane the results in this thesis would give a levelized cost of 180 Euro/t_{BLNG} and a return on investment of 506% and as such make this investment option viable. Comparing that levelized cost to that of the literatures at 315 to 704 Euro/t_{BLNG} [6] and 144 to

342 Euro/t_{BLNG} [7] this thesis results are within the range of the latter source values without the biomethane production cost. With regards to the payback time for the BLNG investment. The simple payback time gives a value of 7.2 years but according to the data in Appendix A, it can be seen that the net present value is still negative at year 10. This means that when the time value of money is taken in consideration the investment has not paid for itself during the time frame chosen. According to the literature [8] [9], regarding the CO_2 liquefaction investment the greater capacity plant have a smaller levelized cost. Going from around 4 Euro/t for the greater capacity plant to 17-18 Euro/t_{LCO2} for a smaller capacity (45 t_{LCO2}/h) plant. Since the plant in this report is much smaller with an output of around 0.5 t_{LCO2}/h it seems possible that the calculated levelized cost of roughly 34 Euro/t_{LCO2} is valid.

Regarding the GHG calculations, the simplifications made there are deemed not to change the outcome of the results to such a great extent. This due to the sensitivity analysis made with both the LCA data and the typical values from RED II showing the same result and the result in this thesis is relatively close to that value. The greatest effect on the GHG calculations seem to be the amount of manure utilized as feedstock since this gives much bonus points and will decrease the total emission factor for the biomethane from 21 $g_{CO2\text{-}eq}$ /MJ to 17 $g_{CO2\text{-}eq}$ /MJ. RED II [2] states the typical emission factors for biomethane from 50 $g_{CO2\text{-}eq}$/MJ with only maize as feedstock and down to -103 $g_{CO2\text{-}eq}$/MJ with manure as the only feedstock. If looking closer to for example a mixture of 60% manure and 40% maize the emission factors are between 7 $g_{CO2\text{-}eq}$/MJ and 36 $g_{CO2\text{-}eq}$/MJ. Taking that in account and the values gained from Gustafsson and Svensson [10] that states a GHG saving potential for BLNG from 45% to 125% for transportation, this thesis value of 81% is quite close to the mean values of the literature. Further, it can be seen in 4.2.5 that the plant operator is running the plant in an environmentally friendly manner, since the emission factors of the biomethane are much higher if the plant would be consuming electricity from fossil sources. However, if the plant would get heat and electricity from a CHP plant using straw as fuel, the emission factor would decrease to 16 $g_{CO2\text{-}eq}$ /MJ, compared to 17 $g_{CO2\text{-}eq}$ /MJ, without investments. The sale price of biomethane with an emission factor of -20 $g_{CO2\text{-}eq}$ /MJ was estimated to around 12 Euro cent/kWh [4], approximately 1.67 Euro/kg. This is slightly higher than the sale price utilized in this thesis, that can be seen as the sale price of biomethane without the liquefaction of CO_2. LNG for transportation have a sale price of 2.079 Euro/kg according to source [50] and BLNG have the same basic cost but with a premium on it. This means that the price of BLNG will be higher than that of LNG. This is good in one way, making sure that the producers of BLNG get a good earning on their product. However, it will most likely lead to less sales since the consumers would most likely buy the cheaper fuel, this is probably one of the reasons why

Germany has stricter demands on transportation fuels. Consumers that have a high environmental awareness are most likely to buy the BLNG even if it has a higher price. The sale price of BLNG is very dependent on the emission factor but it also seems to follow the LNG price, as such it will fluctuate quite much, which in turn would make this investment a risk, if it would have been viable. When the emission certificates will be on an open market the prices of it too will most likely fluctuate due to supply and demand. When looking at the sensitivity analysis in this thesis it is clear that the CO_2 liquefaction investment have a relative high stability against fluctuations in the investment cost, electricity cost, and the sale price of LCO_2, the investment will stay feasible even with fluctuation costs. The opposite can be said regarding the liquefaction of biomethane investment. The changes are relatively great, this is most likely due to that to different costs are a great part of the investment while the revenue is relatively small.

The market for LCO_2 is deemed to be relatively small in the near future but expected to grow in the long run, specifically for building materials, a large potential for the production of fuel using CO_2 is expected as well. The greatest barrier to an increasing market for the use of CO_2 are not technological but depending on regulations and the economical aspects. The global consumption of CO_2 is estimated by the International Energy Agency to grow from 250 million ton/year the year 2020 to 272 million ton/year in the year 2025. Depending on scenarios used, the estimated annual increase in the use of CO_2 to the year 2030 are less than 1 000 million ton/year to a very unlikely 7 000 million ton/year. If, they use the clean energy scenario together with a reduction in the capacity for carbon storage the estimate is an increase of 77% between the year 2030 and 2060 [51].

6 Conclusions

6.1 Study results

The production of biogas and biomethane is an excellent way of reducing wastes and produce energy in a sustainable way. Both liquefaction of CO_2 and the liquefaction of biomethane is conducted with similar processes. The main difference is that the biomethane must be cooled down much more than the CO_2.

Liquefied biomethane could help offset a lot of fossil fuel and be a good fuel source for the farmers around the biomethane plant. However, small-scale liquefaction of biomethane up to 350 Nm^3/h biomethane input is not an economically profitable investment at the current time. The investment costs for these technologies must decrease substantially or the sale price for BLNG must increase much before it will be a stable option for biomethane plants with lower or similar production capacity. As it stands now this option is not viable due to a long payback time, negative net present value, negative return on investment, and a great sensitivity to changes on the discount rate and the various costs. However, if both investments are seen as one investment and pursued at the same time the investment could be seen as viable due to less sensitivity and positive NPV and ROI. Figure 22 below summarise the economical results of this thesis. It can be seen that the liquefaction of CO_2 (LCO_2) investment is the best option with a short payback time, low investment cost and a high return on investment. Both investments together could be attractive, but it does have a somewhat high payback time and investment cost. The least attractive investment is the liquefaction of biomethane (BLNG) as a sole investment.

Figure 22: Summery of the economical results for both investments option separate and combined, made by author in Excel.

Liquefaction of CO_2 will increase the GHG saving potential with no regard to what the biomethane is utilized for. Be it transportation, electricity production or heat production. The emission factor for biomethane decreased from 17 $g_{CO2\text{-}eq}$/MJ to a negative -23 $g_{CO2\text{-}eq}$/MJ with the added liquefaction of CO_2 investment. This investment would increase the sale price of the biomethane and the possible offset of fossil CO_2 would help reducing the dependency of fossil CO_2. If the BLNG investment would have been a good option it would have only increase the emission factor of biomethane to -21 $g_{CO2\text{-}eq}$/MJ, if the liquefaction of CO_2 also was added. However, it is important to keep in mind that the emission factor of the biomethane is dependent on the sold $LCO_{2,}$ that it is either stored or it is replacing fossil CO_2, proof for those two options must be given to the authorities.

The processes utilized for liquefaction are heavy consumers of electricity but when the electricity is being produced by the plant itself, it is utilizing sustainable energy. The literature seems to agree that the reversed Stirling process have the highest levelized cost while the reversed Rankine cycle is economically the best option with regards to the liquefaction of biomethane. When it comes to the liquefaction of CO_2 the best option seems to be the internal refrigeration process but in general the cost difference between the two processes seems to be quite small and in the authors opinion it can be generalized to the same cost. One other conclusion that can be drawn from this thesis is that environmental and economical assessment of small-scale liquefaction seem to be relatively unexplored in the scientific community, there is a lack of scientific literature covering this topic.

It can finally be concluded that it is according to the author, based on the data in this thesis not profitable to invest in the liquefaction of biomethane until the investment cost is highly reduced, the sale price of BLNG have increased, or perhaps if the biomethane input to the liquefaction plant is increased. The liquefaction of CO_2 is a good investment option that could bring an extra income to the plant and offset fossil carbon.

6.2 Outlook

It would be interesting to perform the same study again but taking in proper cost proposals for a plant with this specific size from the manufacturers of the different technologies. It would have been a better and more precise way of performing the economical calculations. To actually measure the quality and quantity of the off-gas would have been a good start but was at the time not an option. It is recommended that cost proposals are collected from suppliers of CO_2 liquefaction plants and that the data from this thesis is compared with that data and actions taken accordingly. It is highly recommended before cost proposals are requested that actual measurements of the off-gas is carried out, this since more cleaning of the gas could be needed before it enters the CO_2 liquefaction plant. An interesting continuation of this thesis would be to investigate how an added investment in algae production utilizing the LCO_2 from the plant would affect the methane yield and the economy of the whole plant when being added to the digesters. Better policies and incitements for small scale biomethane liquefaction should be formed to make it a viable option and help reduce the emissions from the heavy transportation sector that stands for roughly 25% [10] of the transportation sector total emissions. As seen in chapter 2.3, to calculate the CO_2 as captured and stored, it is stated that the carbon must be stored in geological formations. With the current regulations it is not viable to sell the LCO_2 for purpose of storage in building materials. The regulation needs to be changed to also include other storing options than in geological formations.

6.3 Perspectives

With the liquefaction of CO_2 the GHG emissions would be negative and utilizing biomethane as an energy source will reduce the total GHG emissions and help moving closer to the goals formulated in RED II. From an energy system point of view biomethane is best utilized in hybrid heat pumps to heat older buildings already connected to the gas grid. Biomethane with low emission will also be of great value as a fuel for peak power plants such as gas turbines. In the industry the biomethane can be utilized as a fuel for supplying high heat demands and as mentioned in this thesis help reduce emissions from the transportation sector if it is liquefied, since the energy density increase. Biogas and biomethane plants in general increase the employment rate outside of cities due to the needed work force to run the plant and potentially grow and collect the feedstocks [52]. Looking at the sustainable development goals [53] that consist of 17 goals to improve the conditions for all life forms on this planet, biomethane with the liquefaction of CO_2 and liquefied biomethane can help achieving many of the goals. With less emissions the health for humans, plant-based life and animals be it above or under the sea can be improved to a great extent. This by sustainable waste management, improved biodiversity, and reverse land degradation. Poverty can be reduced due to an increase in employment rates followed by people will be able to afford cleaner energy. If the liquefied CO_2 is utilized in greenhouses to cultivate food, the food production can increase to a great extent and help reduce starvation.

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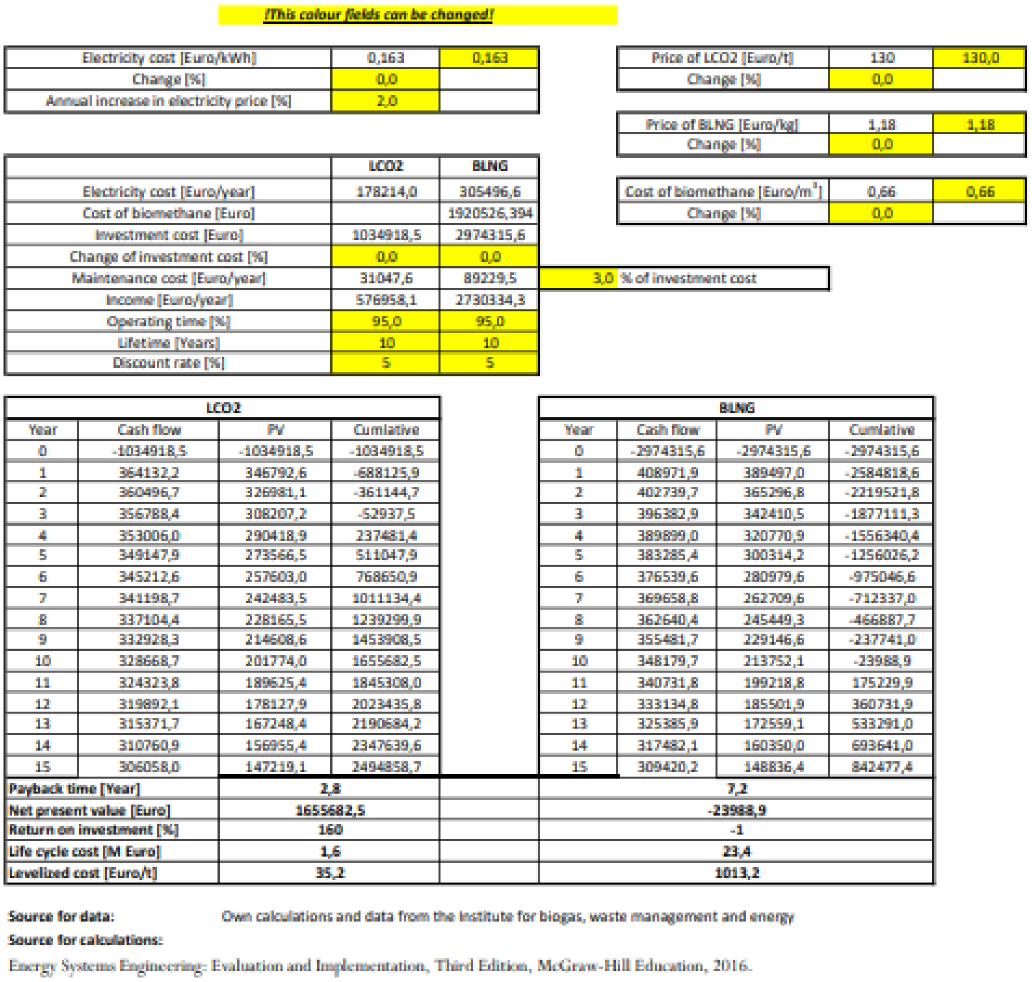
Appendix A

Economical Data:



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Electricity cost [Euro/kWh]	0,163	0,163
Change [%]	0,0	
Annual increase in electricity price [%]	2,0	

Price of LCO2 [Euro/t]	130	130,0
Change [%]	0,0	

Price of BLNG [Euro/kg]	1,18	1,18
Change [%]	0,0	

Cost of biomethane [Euro/m³]	0,66	0,66
Change [%]	0,0	

	LCO2	BLNG		
Electricity cost [Euro/year]	178214,0	305496,6		
Cost of biomethane [Euro]		1920526,394		
Investment cost [Euro]	1034918,5	2974315,6		
Change of investment cost [%]	0,0	0,0		
Maintenance cost [Euro/year]	31047,6	89229,5	3,0	% of investment cost
Income [Euro/year]	576958,1	2730334,3		
Operating time [%]	95,0	95,0		
Lifetime [Years]	10	10		
Discount rate [%]	5	5		

LCO2			
Year	Cash flow	PV	Cumlative
0	-1034918,5	-1034918,5	-1034918,5
1	364132,2	346792,6	-688125,9
2	360496,7	326981,1	-361144,7
3	356788,4	308207,2	-52937,5
4	353006,0	290418,9	237481,4
5	349147,9	273566,5	511047,9
6	345212,6	257603,0	768650,9
7	341198,7	242483,5	1011134,4
8	337104,4	228165,5	1239299,9
9	332928,3	214608,6	1453908,5
10	328668,7	201774,0	1655682,5
11	324323,8	189625,4	1845308,0
12	319892,1	178127,9	2023435,8
13	315371,7	167248,4	2190684,2
14	310760,9	156955,4	2347639,6
15	306058,0	147219,1	2494858,7

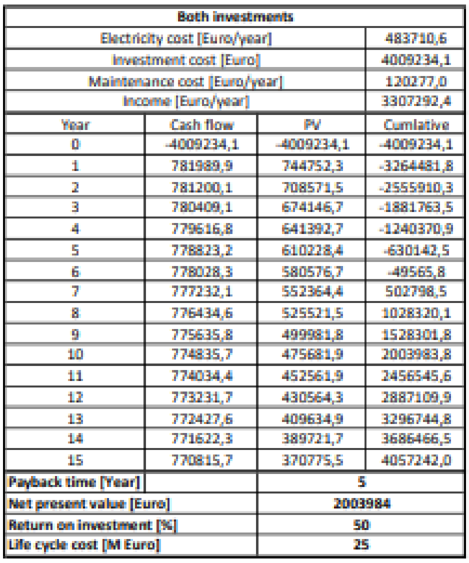
BLNG			
Year	Cash flow	PV	Cumlative
0	-2974315,6	-2974315,6	-2974315,6
1	408971,9	389497,0	-2584818,6
2	402739,7	365296,8	-2219521,8
3	396382,9	342410,5	-1877111,3
4	389899,0	320770,9	-1556340,4
5	383285,4	300314,2	-1256026,2
6	376539,6	280979,6	-975046,6
7	369658,8	262709,6	-712337,0
8	362640,4	245449,3	-466887,7
9	355481,7	229146,6	-237741,0
10	348179,7	213752,1	-23988,9
11	340731,8	199218,8	175229,9
12	333134,8	185501,9	360731,9
13	325385,9	172559,1	533291,0
14	317482,1	160350,0	693641,0
15	309420,2	148836,4	842477,4

	LCO2	BLNG
Payback time [Year]	**2,8**	**7,2**
Net present value [Euro]	**1655682,5**	**-23988,9**
Return on investment [%]	**160**	**-1**
Life cycle cost [M Euro]	**1,6**	**23,4**
Levelized cost [Euro/t]	**35,2**	**1013,2**

Source for data: Own calculations and data from the institute for biogas, waste management and energy

Source for calculations:

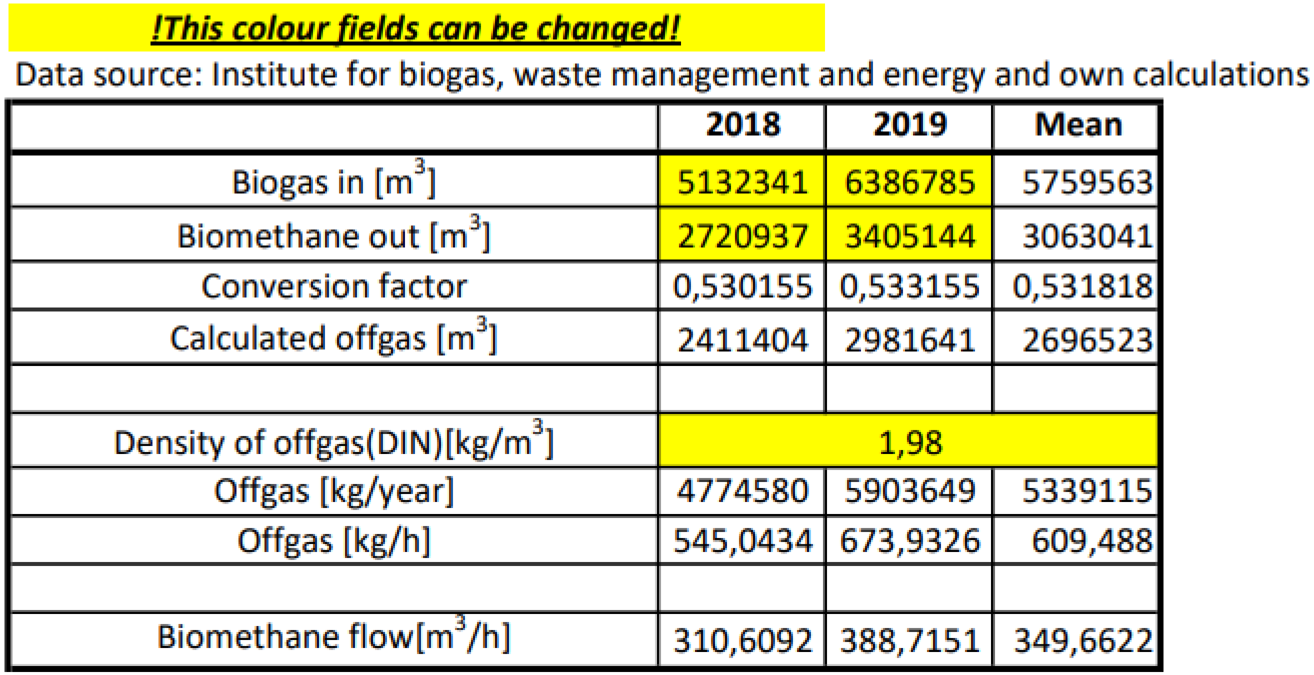
Energy Systems Engineering: Evaluation and Implementation, Third Edition, McGraw-Hill Education, 2016.



Both investments			
Electricity cost [Euro/year]			483710,6
Investment cost [Euro]			4009234,1
Maintenance cost [Euro/year]			120277,0
Income [Euro/year]			3307292,4
Year	Cash flow	PV	Cumlative
0	-4009234,1	-4009234,1	-4009234,1
1	781989,9	744752,3	-3264481,8
2	781200,1	708571,5	-2555910,3
3	780409,1	674146,7	-1881763,5
4	779616,8	641392,7	-1240370,9
5	778823,2	610228,4	-630142,5
6	778028,3	580576,7	-49565,8
7	777232,1	552364,4	502798,5
8	776434,6	525521,5	1028320,1
9	775635,8	499981,8	1528301,8
10	774835,7	475681,9	2003983,8
11	774034,4	452561,9	2456545,6
12	773231,7	430564,3	2887109,9
13	772427,6	409634,9	3296744,8
14	771622,3	389721,7	3686466,5
15	770815,7	370775,5	4057242,0
Payback time [Year]		**5**	
Net present value [Euro]		**2003984**	
Return on investment [%]		**50**	
Life cycle cost [M Euro]		**25**	

Appendix B

Upgrading plant data:



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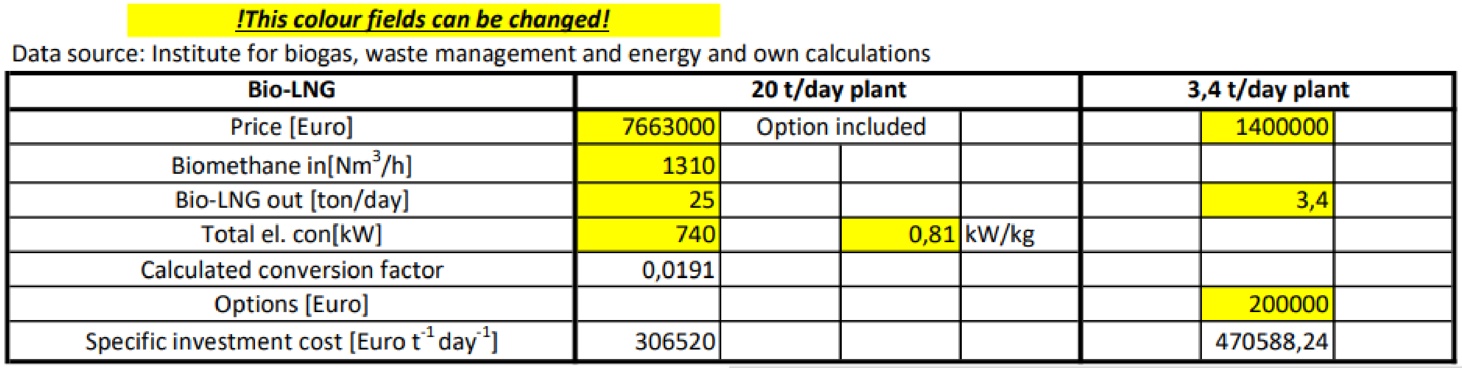
Data source: Institute for biogas, waste management and energy and own calculations

	2018	2019	Mean
Biogas in [m^3]	5132341	6386785	5759563
Biomethane out [m^3]	2720937	3405144	3063041
Conversion factor	0,530155	0,533155	0,531818
Calculated offgas [m^3]	2411404	2981641	2696523
Density of offgas(DIN)[kg/m^3]	1,98		
Offgas [kg/year]	4774580	5903649	5339115
Offgas [kg/h]	545,0434	673,9326	609,488
Biomethane flow[m^3/h]	310,6092	388,7151	349,6622

BLNG data:



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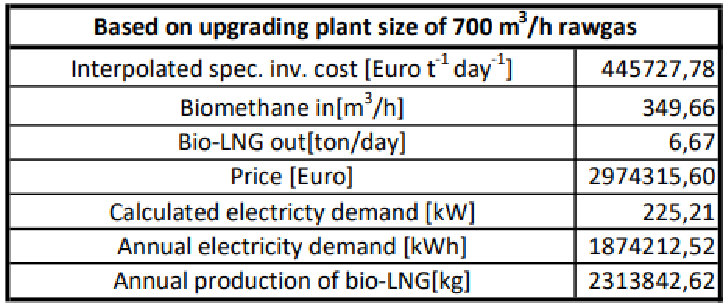
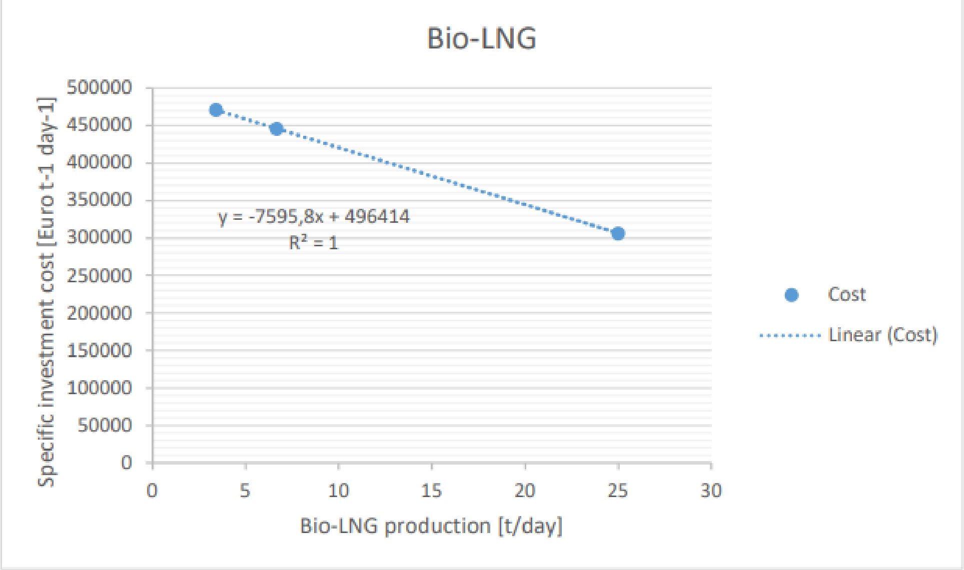
Data source: Institute for biogas, waste management and energy and own calculations

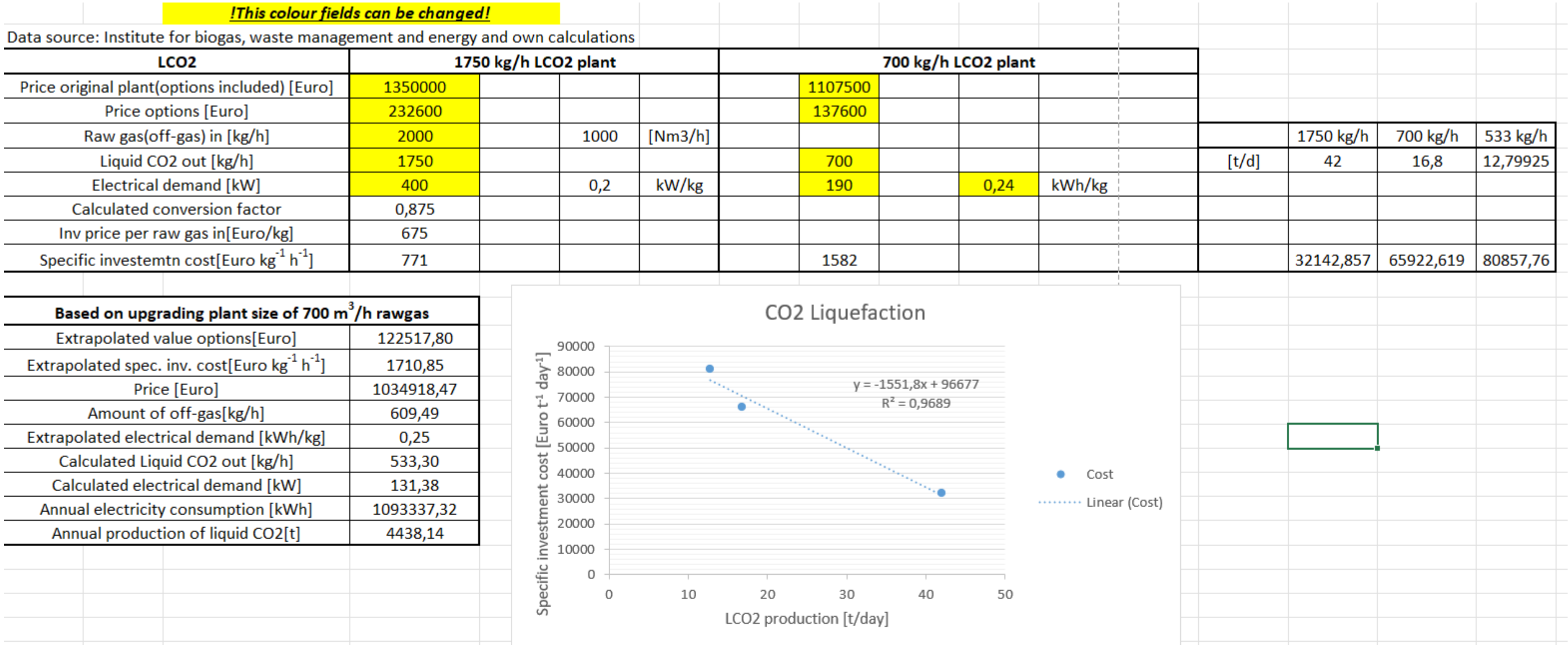
Bio-LNG	20 t/day plant				3,4 t/day plant		
Price [Euro]	7663000	Option included				1400000	
Biomethane in[Nm^3/h]	1310						
Bio-LNG out [ton/day]	25					3,4	
Total el. con[kW]	740		0,81	kW/kg			
Calculated conversion factor	0,0191						
Options [Euro]						200000	
Specific investment cost [Euro t^{-1} day^{-1}]	306520					470588,24	



Based on upgrading plant size of 700 m^3/h rawgas	
Interpolated spec. inv. cost [Euro t^{-1} day^{-1}]	445727,78
Biomethane in[m^3/h]	349,66
Bio-LNG out[ton/day]	6,67
Price [Euro]	2974315,60
Calculated electricty demand [kW]	225,21
Annual electricity demand [kWh]	1874212,52
Annual production of bio-LNG[kg]	2313842,62



LCO_2 data:



!This colour fields can be changed!

Data source: Institute for biogas, waste management and energy and own calculations

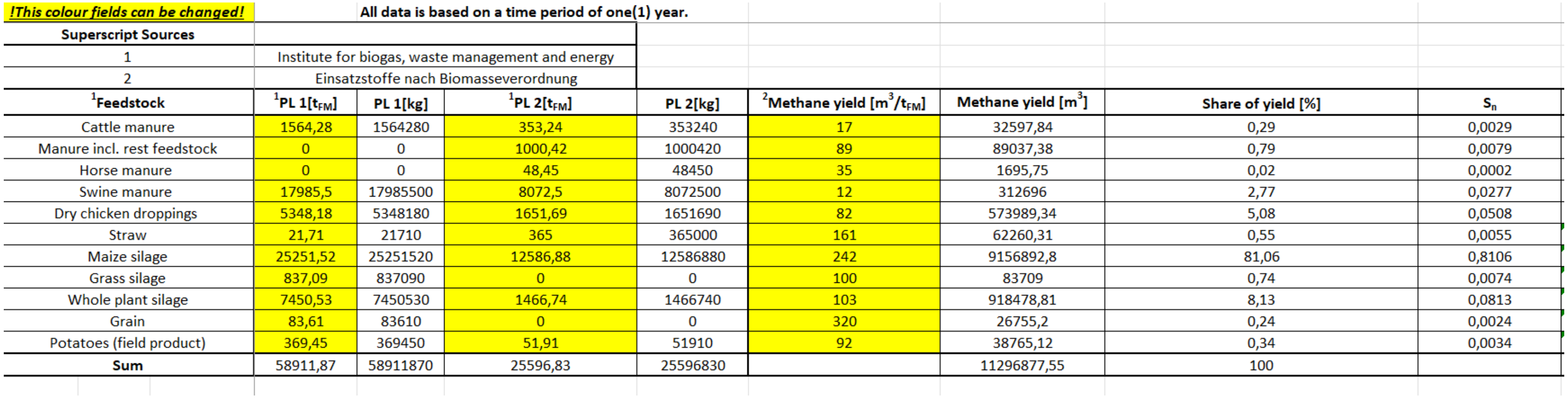
LCO2	1750 kg/h LCO2 plant				700 kg/h LCO2 plant				
Price original plant(options included) [Euro]	1350000					1107500			
Price options [Euro]	232600					137600			
Raw gas(off-gas) in [kg/h]	2000		1000	[Nm3/h]					
Liquid CO2 out [kg/h]	1750					700			
Electrical demand [kW]	400		0,2	kW/kg		190		0,24	kWh/kg
Calculated conversion factor	0,875								
Inv price per raw gas in[Euro/kg]	675								
Specific investemtn cost[Euro kg^{-1} h^{-1}]	771					1582			

	1750 kg/h	700 kg/h	533 kg/h
[t/d]	42	16,8	12,79925
	32142,857	65922,619	80857,76

Based on upgrading plant size of 700 m^3/h rawgas	
Extrapolated value options[Euro]	122517,80
Extrapolated spec. inv. cost[Euro kg^{-1} h^{-1}]	1710,85
Price [Euro]	1034918,47
Amount of off-gas[kg/h]	609,49
Extrapolated electrical demand [kWh/kg]	0,25
Calculated Liquid CO2 out [kg/h]	533,30
Calculated electrical demand [kW]	131,38
Annual electricity consumption [kWh]	1093337,32
Annual production of liquid CO2[t]	4438,14

Appendix C

GHG calculations data:



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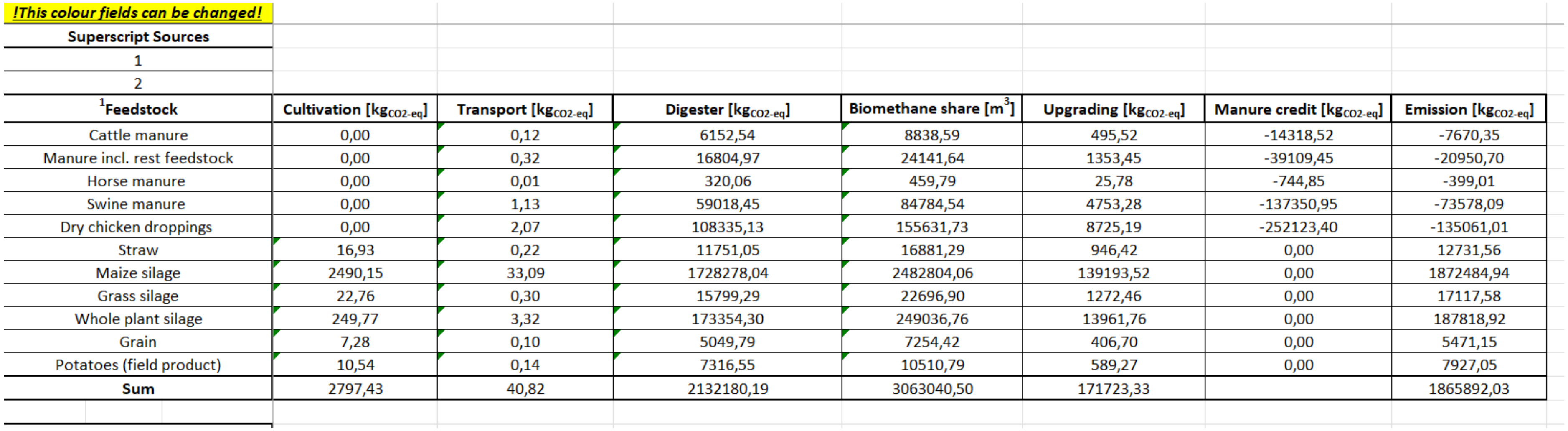
All data is based on a time period of one(1) year.

Superscript Sources	
1	Institute for biogas, waste management and energy
2	Einsatzstoffe nach Biomasseverordnung

[1]Feedstock	**[1]PL 1[t_{FM}]**	**PL 1[kg]**	**[1]PL 2[t_{FM}]**	**PL 2[kg]**	**[2]Methane yield [m^3/t_{FM}]**	**Methane yield [m^3]**	**Share of yield [%]**	**S_n**
Cattle manure	1564,28	1564280	353,24	353240	17	32597,84	0,29	0,0029
Manure incl. rest feedstock	0	0	1000,42	1000420	89	89037,38	0,79	0,0079
Horse manure	0	0	48,45	48450	35	1695,75	0,02	0,0002
Swine manure	17985,5	17985500	8072,5	8072500	12	312696	2,77	0,0277
Dry chicken droppings	5348,18	5348180	1651,69	1651690	82	573989,34	5,08	0,0508
Straw	21,71	21710	365	365000	161	62260,31	0,55	0,0055
Maize silage	25251,52	25251520	12586,88	12586880	242	9156892,8	81,06	0,8106
Grass silage	837,09	837090	0	0	100	83709	0,74	0,0074
Whole plant silage	7450,53	7450530	1466,74	1466740	103	918478,81	8,13	0,0813
Grain	83,61	83610	0	0	320	26755,2	0,24	0,0024
Potatoes (field product)	369,45	369450	51,91	51910	92	38765,12	0,34	0,0034
Sum	58911,87	58911870	25596,83	25596830		11296877,55	100	



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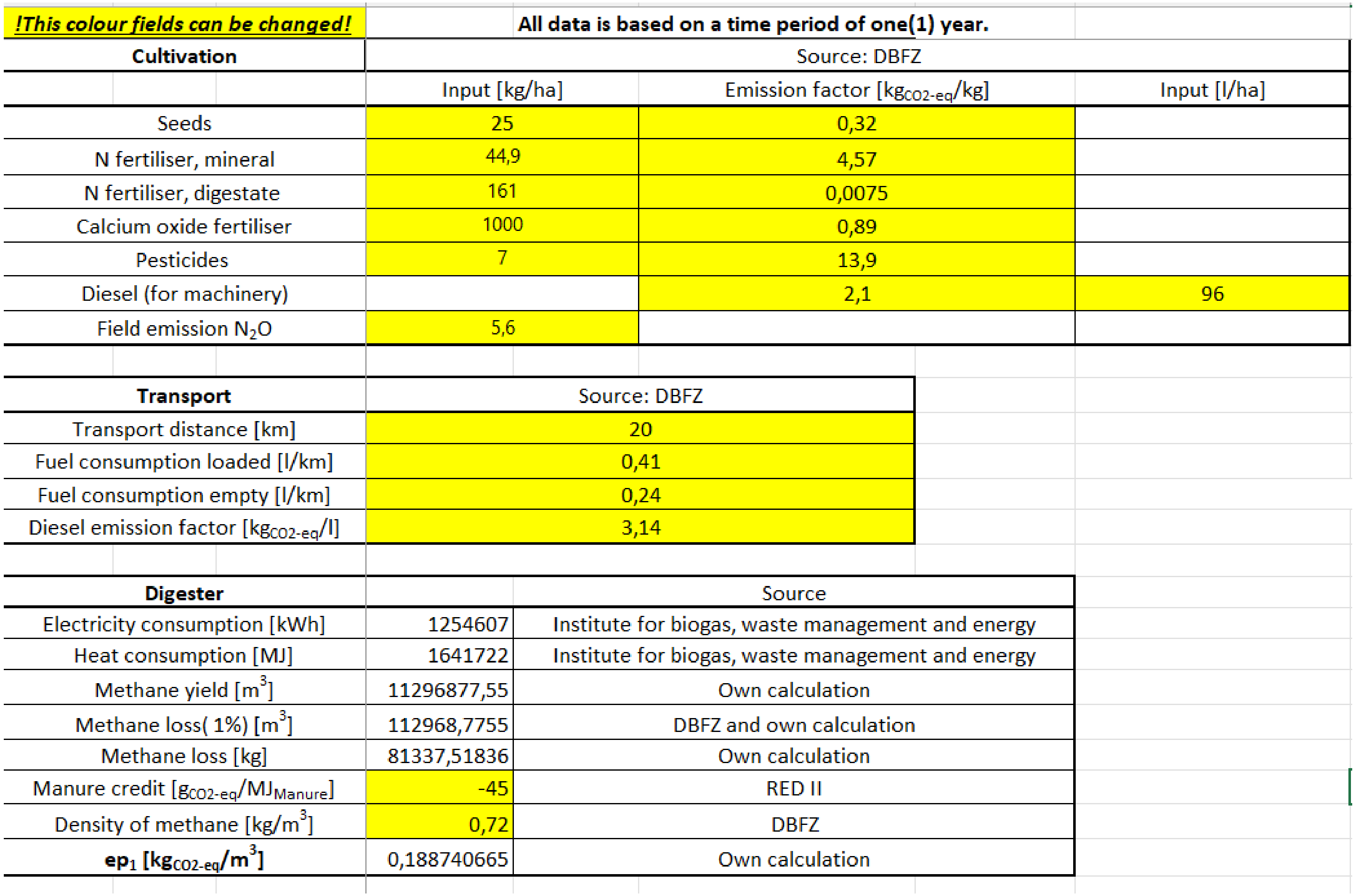
Superscript Sources

1

2

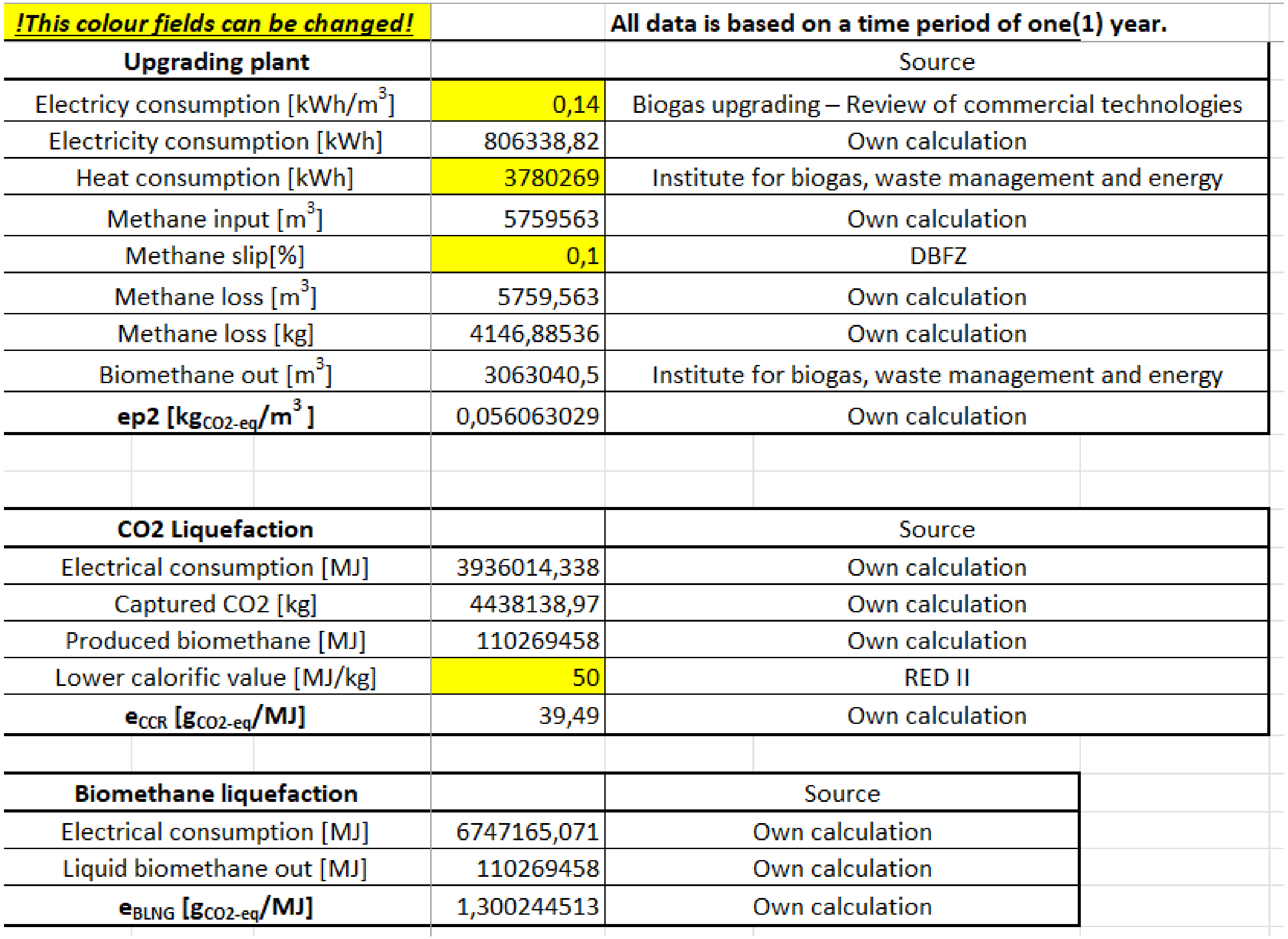
[1]**Feedstock**	**Cultivation [kg$_{CO2\text{-}eq}$]**	**Transport [kg$_{CO2\text{-}eq}$]**	**Digester [kg$_{CO2\text{-}eq}$]**	**Biomethane share [m^3]**	**Upgrading [kg$_{CO2\text{-}eq}$]**	**Manure credit [kg$_{CO2\text{-}eq}$]**	**Emission [kg$_{CO2\text{-}eq}$]**
Cattle manure	0,00	0,12	6152,54	8838,59	495,52	-14318,52	-7670,35
Manure incl. rest feedstock	0,00	0,32	16804,97	24141,64	1353,45	-39109,45	-20950,70
Horse manure	0,00	0,01	320,06	459,79	25,78	-744,85	-399,01
Swine manure	0,00	1,13	59018,45	84784,54	4753,28	-137350,95	-73578,09
Dry chicken droppings	0,00	2,07	108335,13	155631,73	8725,19	-252123,40	-135061,01
Straw	16,93	0,22	11751,05	16881,29	946,42	0,00	12731,56
Maize silage	2490,15	33,09	1728278,04	2482804,06	139193,52	0,00	1872484,94
Grass silage	22,76	0,30	15799,29	22696,90	1272,46	0,00	17117,58
Whole plant silage	249,77	3,32	173354,30	249036,76	13961,76	0,00	187818,92
Grain	7,28	0,10	5049,79	7254,42	406,70	0,00	5471,15
Potatoes (field product)	10,54	0,14	7316,55	10510,79	589,27	0,00	7927,05
Sum	2797,43	40,82	2132180,19	3063040,50	171723,33		1865892,03



!This colour fields can be changed!	**All data is based on a time period of one(1) year.**		
Cultivation	Source: DBFZ		
	Input [kg/ha]	Emission factor [kg_{CO2-eq}/kg]	Input [l/ha]
Seeds	25	0,32	
N fertiliser, mineral	44,9	4,57	
N fertiliser, digestate	161	0,0075	
Calcium oxide fertiliser	1000	0,89	
Pesticides	7	13,9	
Diesel (for machinery)		2,1	96
Field emission N_2O	5,6		

Transport	Source: DBFZ
Transport distance [km]	20
Fuel consumption loaded [l/km]	0,41
Fuel consumption empty [l/km]	0,24
Diesel emission factor [kg_{CO2-eq}/l]	3,14

Digester		Source
Electricity consumption [kWh]	1254607	Institute for biogas, waste management and energy
Heat consumption [MJ]	1641722	Institute for biogas, waste management and energy
Methane yield [m^3]	11296877,55	Own calculation
Methane loss(1%) [m^3]	112968,7755	DBFZ and own calculation
Methane loss [kg]	81337,51836	Own calculation
Manure credit [g_{CO2-eq}/MJ_{Manure}]	-45	RED II
Density of methane [kg/m^3]	0,72	DBFZ
ep_1 [kg_{CO2-eq}/m^3]	0,188740665	Own calculation

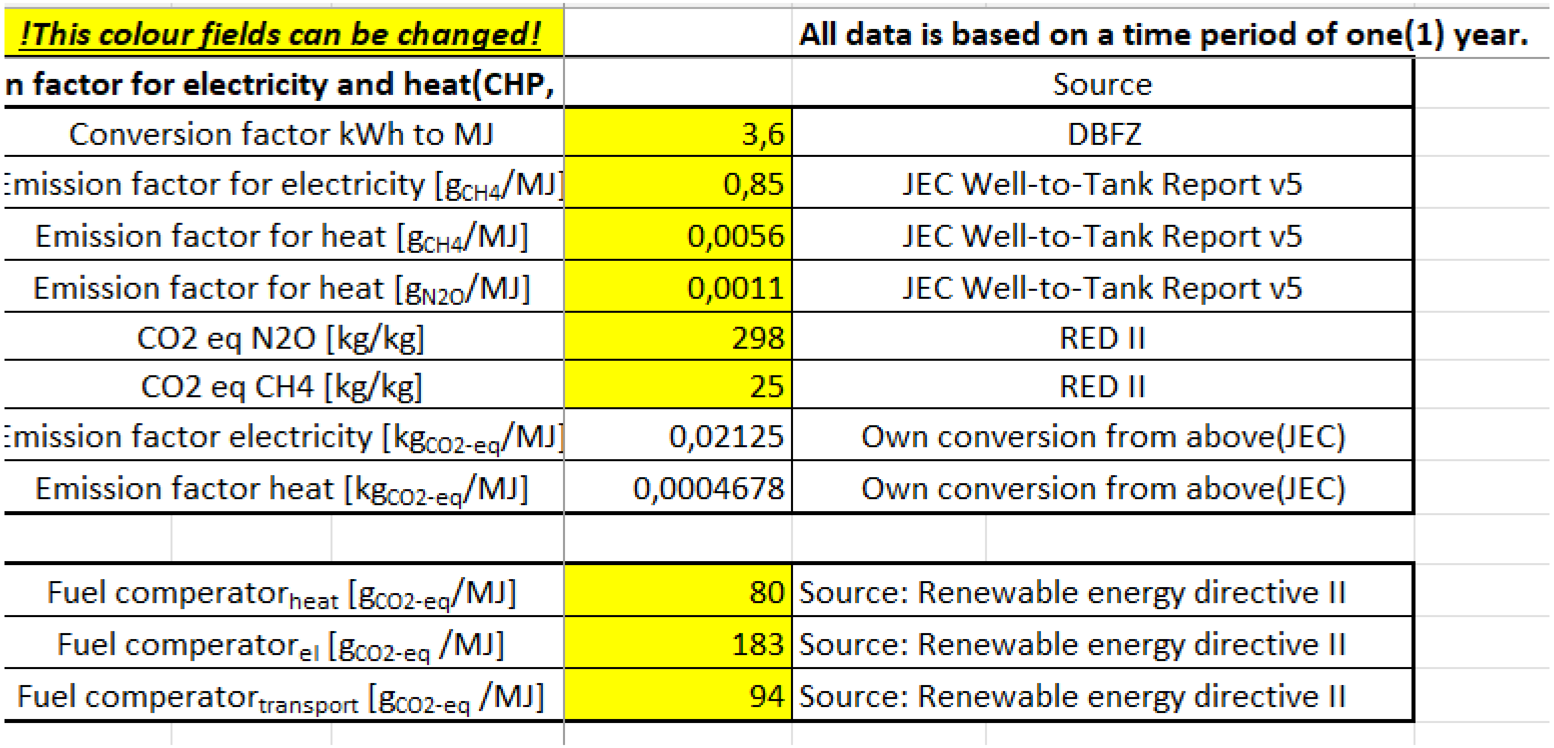


!This colour fields can be changed! **All data is based on a time period of one(1) year.**

Upgrading plant		Source
Electricy consumption [kWh/m^3]	0,14	Biogas upgrading – Review of commercial technologies
Electricity consumption [kWh]	806338,82	Own calculation
Heat consumption [kWh]	3780269	Institute for biogas, waste management and energy
Methane input [m^3]	5759563	Own calculation
Methane slip[%]	0,1	DBFZ
Methane loss [m^3]	5759,563	Own calculation
Methane loss [kg]	4146,88536	Own calculation
Biomethane out [m^3]	3063040,5	Institute for biogas, waste management and energy
ep2 [$kg_{CO2\text{-}eq}/m^3$]	0,056063029	Own calculation

CO2 Liquefaction		Source
Electrical consumption [MJ]	3936014,338	Own calculation
Captured CO2 [kg]	4438138,97	Own calculation
Produced biomethane [MJ]	110269458	Own calculation
Lower calorific value [MJ/kg]	50	RED II
e_{CCR} [$g_{CO2\text{-}eq}$/MJ]	39,49	Own calculation

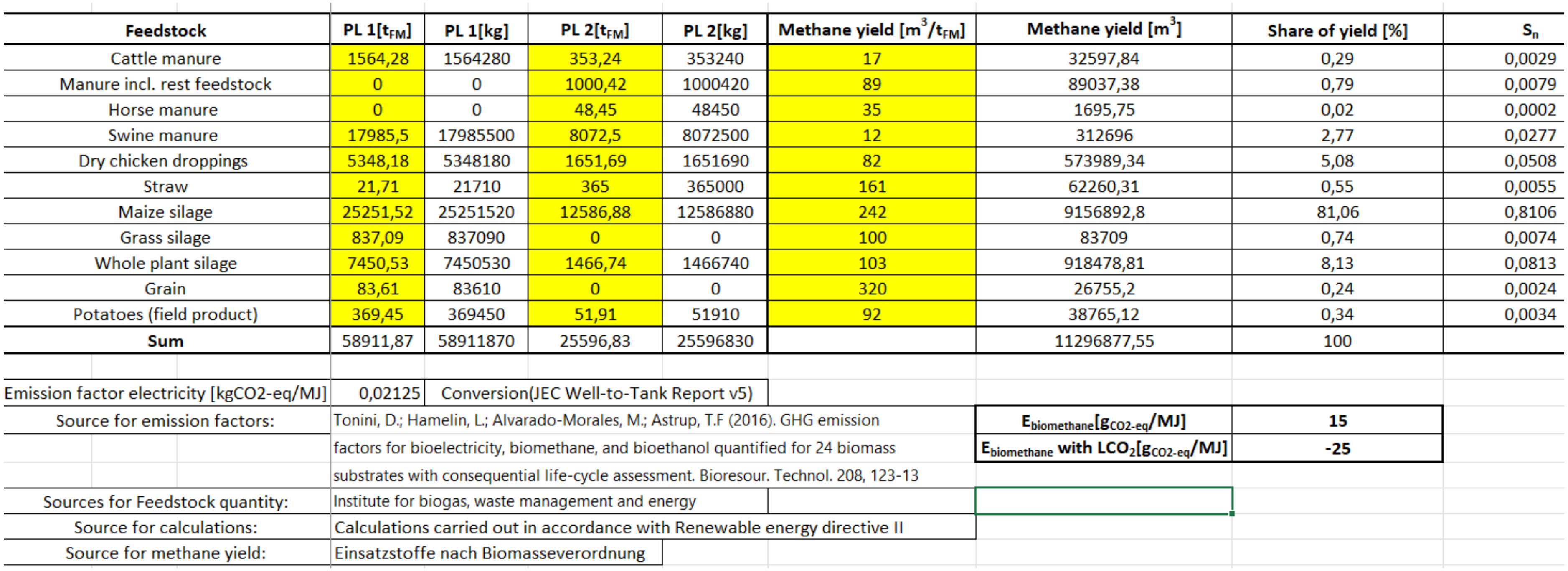
Biomethane liquefaction		Source
Electrical consumption [MJ]	6747165,071	Own calculation
Liquid biomethane out [MJ]	110269458	Own calculation
e_{BLNG} [$g_{CO2\text{-}eq}$/MJ]	1,300244513	Own calculation



!This colour fields can be changed!		**All data is based on a time period of one(1) year.**
n factor for electricity and heat(CHP,		Source
Conversion factor kWh to MJ	3,6	DBFZ
mission factor for electricity [g_{CH4}/MJ]	0,85	JEC Well-to-Tank Report v5
Emission factor for heat [g_{CH4}/MJ]	0,0056	JEC Well-to-Tank Report v5
Emission factor for heat [g_{N2O}/MJ]	0,0011	JEC Well-to-Tank Report v5
CO2 eq N2O [kg/kg]	298	RED II
CO2 eq CH4 [kg/kg]	25	RED II
mission factor electricity [kg_{CO2-eq}/MJ]	0,02125	Own conversion from above(JEC)
Emission factor heat [kg_{CO2-eq}/MJ]	0,0004678	Own conversion from above(JEC)

Fuel comperator$_{heat}$ [g_{CO2-eq}/MJ]	80	Source: Renewable energy directive II
Fuel comperator$_{el}$ [g_{CO2-eq} /MJ]	183	Source: Renewable energy directive II
Fuel comperator$_{transport}$ [g_{CO2-eq} /MJ]	94	Source: Renewable energy directive II

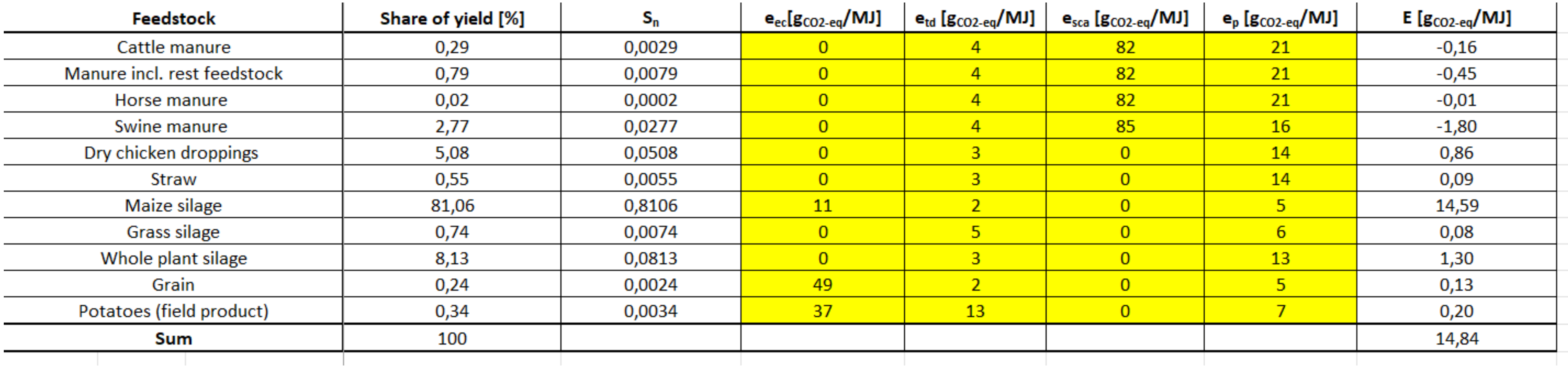
Data for sensitivity analysis of GHG emission utilizing LCA values:



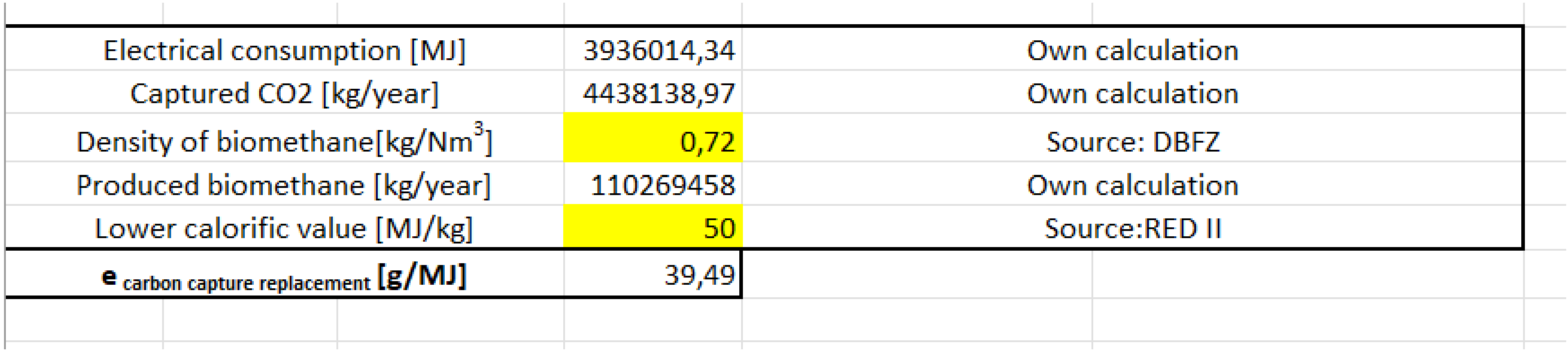
Feedstock	PL 1[t_{FM}]	PL 1[kg]	PL 2[t_{FM}]	PL 2[kg]	Methane yield [m^3/t_{FM}]	Methane yield [m^3]	Share of yield [%]	S_n
Cattle manure	1564,28	1564280	353,24	353240	17	32597,84	0,29	0,0029
Manure incl. rest feedstock	0	0	1000,42	1000420	89	89037,38	0,79	0,0079
Horse manure	0	0	48,45	48450	35	1695,75	0,02	0,0002
Swine manure	17985,5	17985500	8072,5	8072500	12	312696	2,77	0,0277
Dry chicken droppings	5348,18	5348180	1651,69	1651690	82	573989,34	5,08	0,0508
Straw	21,71	21710	365	365000	161	62260,31	0,55	0,0055
Maize silage	25251,52	25251520	12586,88	12586880	242	9156892,8	81,06	0,8106
Grass silage	837,09	837090	0	0	100	83709	0,74	0,0074
Whole plant silage	7450,53	7450530	1466,74	1466740	103	918478,81	8,13	0,0813
Grain	83,61	83610	0	0	320	26755,2	0,24	0,0024
Potatoes (field product)	369,45	369450	51,91	51910	92	38765,12	0,34	0,0034
Sum	58911,87	58911870	25596,83	25596830		11296877,55	100	

Emission factor electricity [kgCO2-eq/MJ]	0,02125	Conversion(JEC Well-to-Tank Report v5)
Source for emission factors:	Tonini, D.; Hamelin, L.; Alvarado-Morales, M.; Astrup, T.F (2016). GHG emission factors for bioelectricity, biomethane, and bioethanol quantified for 24 biomass substrates with consequential life-cycle assessment. Bioresour. Technol. 208, 123-13	
Sources for Feedstock quantity:	Institute for biogas, waste management and energy	
Source for calculations:	Calculations carried out in accordance with Renewable energy directive II	
Source for methane yield:	Einsatzstoffe nach Biomasseverordnung	

$E_{biomethane}[g_{CO2\text{-}eq}/MJ]$	**15**
$E_{biomethane}$ with $LCO_2[g_{CO2\text{-}eq}/MJ]$	**-25**

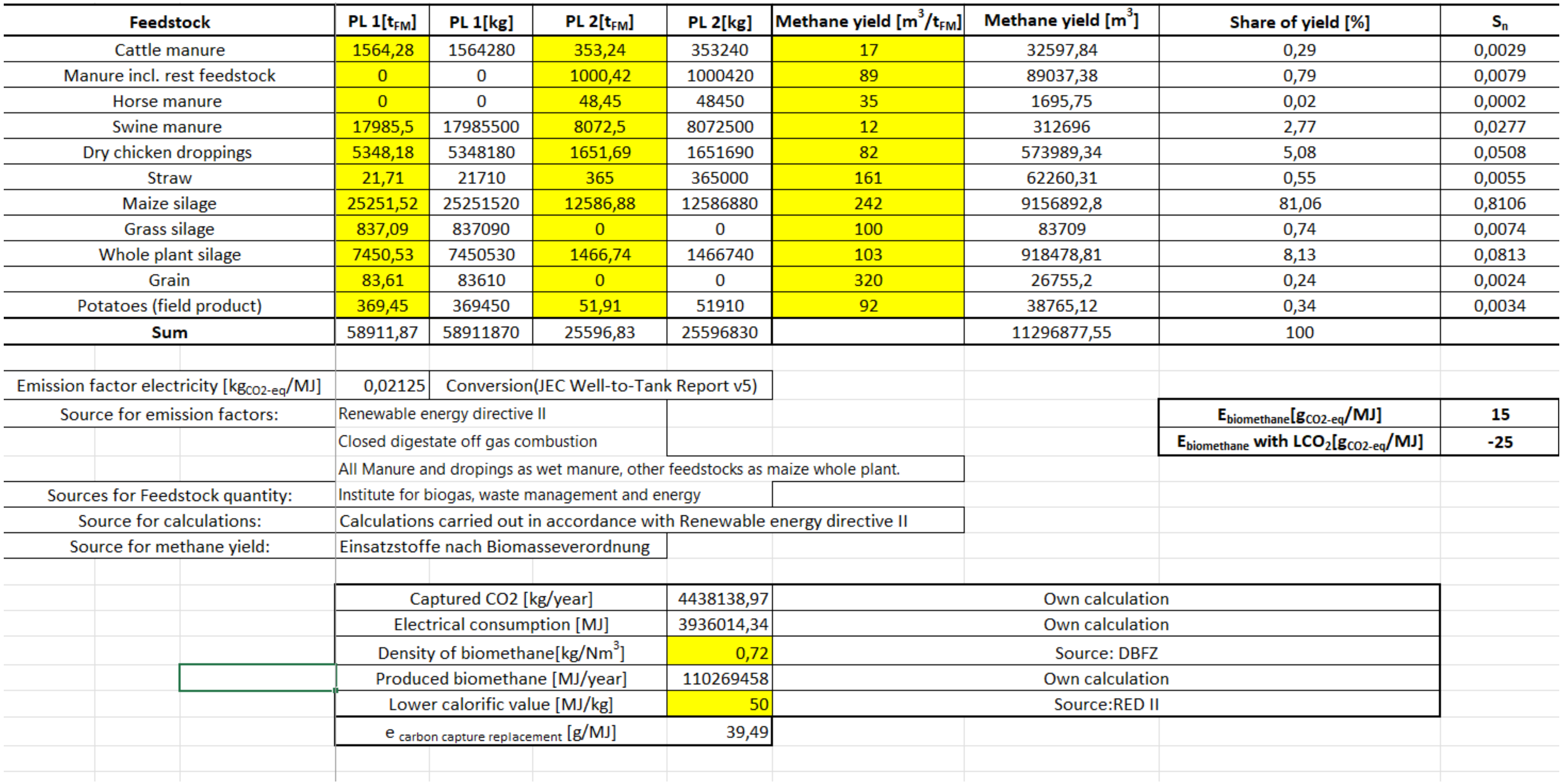


Feedstock	**Share of yield [%]**	**S_n**	**e_{ec}[g_{CO2-eq}/MJ]**	**e_{td} [g_{CO2-eq}/MJ]**	**e_{sca} [g_{CO2-eq}/MJ]**	**e_p [g_{CO2-eq}/MJ]**	**E [g_{CO2-eq}/MJ]**
Cattle manure	0,29	0,0029	0	4	82	21	-0,16
Manure incl. rest feedstock	0,79	0,0079	0	4	82	21	-0,45
Horse manure	0,02	0,0002	0	4	82	21	-0,01
Swine manure	2,77	0,0277	0	4	85	16	-1,80
Dry chicken droppings	5,08	0,0508	0	3	0	14	0,86
Straw	0,55	0,0055	0	3	0	14	0,09
Maize silage	81,06	0,8106	11	2	0	5	14,59
Grass silage	0,74	0,0074	0	5	0	6	0,08
Whole plant silage	8,13	0,0813	0	3	0	13	1,30
Grain	0,24	0,0024	49	2	0	5	0,13
Potatoes (field product)	0,34	0,0034	37	13	0	7	0,20
Sum	100						14,84



Electrical consumption [MJ]	3936014,34	Own calculation
Captured CO2 [kg/year]	4438138,97	Own calculation
Density of biomethane[kg/Nm^3]	0,72	Source: DBFZ
Produced biomethane [kg/year]	110269458	Own calculation
Lower calorific value [MJ/kg]	50	Source:RED II
$e_{\text{carbon capture replacement}}$ [g/MJ]	39,49	

Data for sensitivity analysis of GHG emission utilizing RED II typical values:

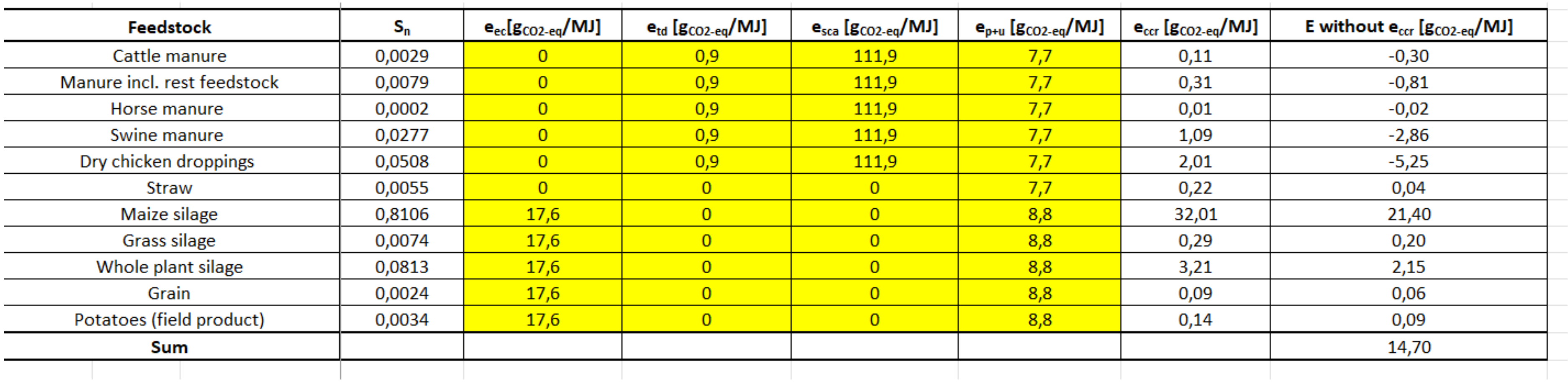


Feedstock	**PL 1[t_{FM}]**	**PL 1[kg]**	**PL 2[t_{FM}]**	**PL 2[kg]**	**Methane yield [m^3/t_{FM}]**	**Methane yield [m^3]**	**Share of yield [%]**	**S_n**
Cattle manure	1564,28	1564280	353,24	353240	17	32597,84	0,29	0,0029
Manure incl. rest feedstock	0	0	1000,42	1000420	89	89037,38	0,79	0,0079
Horse manure	0	0	48,45	48450	35	1695,75	0,02	0,0002
Swine manure	17985,5	17985500	8072,5	8072500	12	312696	2,77	0,0277
Dry chicken droppings	5348,18	5348180	1651,69	1651690	82	573989,34	5,08	0,0508
Straw	21,71	21710	365	365000	161	62260,31	0,55	0,0055
Maize silage	25251,52	25251520	12586,88	12586880	242	9156892,8	81,06	0,8106
Grass silage	837,09	837090	0	0	100	83709	0,74	0,0074
Whole plant silage	7450,53	7450530	1466,74	1466740	103	918478,81	8,13	0,0813
Grain	83,61	83610	0	0	320	26755,2	0,24	0,0024
Potatoes (field product)	369,45	369450	51,91	51910	92	38765,12	0,34	0,0034
Sum	58911,87	58911870	25596,83	25596830		11296877,55	100	

Emission factor electricity [$kg_{CO2\text{-}eq}/MJ$]	0,02125	Conversion(JEC Well-to-Tank Report v5)
Source for emission factors:	Renewable energy directive II	
	Closed digestate off gas combustion	
	All Manure and dropings as wet manure, other feedstocks as maize whole plant.	
Sources for Feedstock quantity:	Institute for biogas, waste management and energy	
Source for calculations:	Calculations carried out in accordance with Renewable energy directive II	
Source for methane yield:	Einsatzstoffe nach Biomasseverordnung	

$E_{biomethane}$[$g_{CO2\text{-}eq}/MJ$]	**15**
$E_{biomethane}$ with LCO_2[$g_{CO2\text{-}eq}/MJ$]	**-25**

Captured CO2 [kg/year]	4438138,97	Own calculation
Electrical consumption [MJ]	3936014,34	Own calculation
Density of biomethane[kg/Nm^3]	0,72	Source: DBFZ
Produced biomethane [MJ/year]	110269458	Own calculation
Lower calorific value [MJ/kg]	50	Source:RED II
$e_{\text{carbon capture replacement}}$ [g/MJ]	39,49	



Feedstock	**S_n**	**e_{ec}[$g_{CO2\text{-}eq}$/MJ]**	**e_{td} [$g_{CO2\text{-}eq}$/MJ]**	**e_{sca} [$g_{CO2\text{-}eq}$/MJ]**	**e_{p+u} [$g_{CO2\text{-}eq}$/MJ]**	**e_{ccr} [$g_{CO2\text{-}eq}$/MJ]**	**E without e_{ccr} [$g_{CO2\text{-}eq}$/MJ]**
Cattle manure	0,0029	0	0,9	111,9	7,7	0,11	-0,30
Manure incl. rest feedstock	0,0079	0	0,9	111,9	7,7	0,31	-0,81
Horse manure	0,0002	0	0,9	111,9	7,7	0,01	-0,02
Swine manure	0,0277	0	0,9	111,9	7,7	1,09	-2,86
Dry chicken droppings	0,0508	0	0,9	111,9	7,7	2,01	-5,25
Straw	0,0055	0	0	0	7,7	0,22	0,04
Maize silage	0,8106	17,6	0	0	8,8	32,01	21,40
Grass silage	0,0074	17,6	0	0	8,8	0,29	0,20
Whole plant silage	0,0813	17,6	0	0	8,8	3,21	2,15
Grain	0,0024	17,6	0	0	8,8	0,09	0,06
Potatoes (field product)	0,0034	17,6	0	0	8,8	0,14	0,09
Sum							14,70