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A case study in Uppsala

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Modellering och optimering av ett Power-To-Gas system: En fallstudie i Uppsala

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Populärvetenskaplig sammanfattning

För att det svenska elnätet ska fungera krävs det att balansen på elnätet upprätthålls hela tiden, skillnader mellan produktion och efterfrågan leder till obalans på elnätet. I dagsläget, i Sverige, upprätthålls balansen genom att minska eller öka elproduktionen från vattenkraften. Power-to-gas är en ny teknik som erbjuder ett alternativ eller ett komplement till att upprätthålla balansen på elnätet.

Principen bakom power-to-gas är att elpriset varierar beroende på förhållandet mellan produktion och efterfrågan. När produktionen är högre än efterfrågan sjunker elpriset och vice versa. Power-to-gas använder den billiga elektriciteten till att producera andra energibärare som är lättare att lagra. Ofta används vätgas som energibärare eftersom elektriciteten kan användas till att spjälka vatten i en elektrolysör och produceras vätgas. Vätgasen kan omvandlas i ett ytterligare steg som kallas metanisering. Vid metaniseringen tillförs koldioxid som reagerar med vätgasen antingen genom katalytisk metanisering eller biologisk metanisering. Slutprodukten blir metan som kan användas på samma sätt som naturgas eller biogas, eftersom alla tre produkter består av samma sorts kemiska molekyl. Metan kan antingen förbrännas och producera värme och elektricitet, eller så kan den användas som fordonsbränsle.

En svårighet med power-to-gas är att få systemen ekonomiskt lönsamma eftersom både elektrolysör och metanisering har höga investeringskostnader. Syftet med den här studien var att undersöka hur systemets lönsamhet påverkas av hur biprodukterna används samt av eltillförsel från en egen solcellsanläggning. Ett ytterligare syfte var att undersöka hur ett power-to-methan system kan designas och styras för att producera metan enligt efterfrågan. För att kunna beräkna den ekonomiska lönsamheten behövs en modell av systemet. Därför var ett mål med studien att utveckla en dynamisk modell för att beräkna den ekonomiska lönsamheten. För att bedöma den ekonomiska lönsamheten användes fyra parametrar: "levelised cost of kg methane", "capital expenditure", "net cash flow" samt "net present value".

"Levelised cost of kg methane"(LCOE) defineras som de totala kostnaderna dividerat med mängden producerad metan. LCOE representerar därmed produktionskostnaden per kg metan. För att uppnå ekonomiskt lönsamhet måste LCOE vara lägre än försäljningspriset för metan. "Capital expenditure"(CAPEX) representerar de totala investeringskostnaderna inklusive nödvändiga byten av elektrolysör och metanisering reaktor. "Net cash flow"(NCF) defineras som intäkterna minus de rörliga kostnaderna och ger ett uttryck för den årliga vinsten/förlusten. Om NCF har ett negativt värde är systemet inte lönsamt och vice versa. "Net present value"(NPV) är skillnaden mellan totala kostnader och totala intäkter under systemets hela livslängd, uttryckt i nutida värde. Precis som för NCF så betyder ett negativt värde att systemet, sett över dessa hela livslängd, har högre kostnader än intäkter och därmed är olönsamt.

Eftersom den ekonomiska lönsamheten är beroende av lokala förutsättningar, så som priset av metan, utfördes en fallstudie. I fallstudien integrerades power-to-metan systemet till den nuvarande biogasanläggningen i Uppsala, vilken är en koldioxidkälla, eftersom biogas före uppgradering består av koldioxid och metan.

Den utvecklade dynamiska modellen visade lönsamhetens känslighet för förändringar i investeringskostnader, elpris, pris för metan samt pris för syrgas. Denna känslighet är ofrånkomlig på grund av systemets natur där stora mängder elektricitet konsumeras och stora mängder metan samt syrgas produceras. Den dynamiska modellen visade sig vara lämplig för att beräkna systemets lönsamhet, men man ska vara medveten om att tillförlitliga indata krävs för att få tillförlitliga beräkningsresultat.

Resultatet visade att systemet, med de antaganden som är gjorda, har svårt att bli ekonomiskt lönsamt. Tillgänglig information angående investeringskostnaderna för biologisk metanisering samt priset på syrgas var bristfällig, vilket kan påverka resultatet. Även ett lågt värde på investeringskostnaderna för biologiskt metanisering gav negativt NPV. Ett pris på 7 kr/kg för syrgasen gav positivt NPV, men detta värde är högre än priset som syrgas säljs för. Försäljningen av biprodukten syrgas visade ha stor inverkan på den ekonomiska lönsamheten medan försäljning av restvärme inte påverkade den ekonomiska lönsamheten i särskilt stor utsträckning.

Resultatet visade även att det är ekonomisk lönsamt att installera solceller för egen elproduktion. Dock visade sig en mindre installerad effekt ge bättre ekonomisk lönsamhet än en större installerad effekt. Det tyder på att en installerade effekten anpassad till elektrolysörens effekt ger ökad lönsamhet.

Slutligen undersöktes vad som krävdes för att systemet skulle bli ekonomiskt lönsamt med fokus på de osäkra parametrarna, det vill säga investeringskostnaderna för biologisk metanisering samt priset för syrgas. Resultatet visade att en 60 % reduktion av investeringskostnaderna för biologisk metanisering i kombination med ett syrgaspris på 5 kr/kg gav ett ekonomiskt lönsamt system. Vid ett syrgaspris på 4 kr/kg kunde andra åtgärder så som skattebefrielse av biogas, lägre investeringskostnaderna för elektrolysören eller ett ökat antal drifttimmar ge ett lönsamt system. En kombination av alla åtgärder gav ett NPV på drygt 3,4 miljoner EUR.

Det finns många ytterligare aspekter att undersöka, till exempel möjligheten att omvandla biogasen till flytande biogas. Användningen av syrgas kan undersökas mer i detalj, till exempel genom att undersöka möjligheten att använda syrgasen vid det närliggande reningsverket. Eftersom investeringskostnaderna för biologisk metanisering hade stor påverkan på resultatet vore det även intressant att undersöka om katalytisk metanisering skulle kunna förbättra den ekonomiska lönsamheten.

Executive summary

A dynamic model has been developed to determine the economic performance of a power-to-methane system. The sensitivity analysis shows that the dynamic model behaves correctly, however, the economic parameters are sensitive to changes in the input parameters. This is inevitable because of the nature of the system and with an awareness of the dynamic models' sensitivity, it can be used in further research.

The results of this study show that power-to-methane has potential if an oxygen price of 0.4 kr/kg can be achieved as well as a CAPEX of methanation of 600 EUR/kWel. Further research regarding the CAPEX of methanation as well price of oxygen are needed to determine if this is possible in the future. There are many other possibilities of improving the system that needs further research.

Abstract

This degree project investigated the economic performance of a power-to-methane system. Economic profitability is necessary to establish a new technology, which power-to-methane is, on the commercial market. In this degree project a case study was conducted, in which a power-to-methane system was integrated into the already existing biogas plant in Uppsala. The economic performance of the system was investigated with regard to two aspects: use of by-products and adding solar power. Based on this aspects a number of scenarios was investigated. The aim was to determine how the aspects effected the economic performance and what was required to make the system profitable.

In order to determine the economic performance a dynamic model was developed. The dynamic model was based on a model developed in a previous bachelor thesis as well as a economic model developed by department of Energy and Technology at SLU and collaborators. A combined and elaborated model was used for this thesis.

The results show that power-to-methane can be integrated into the already existing biogas plant to increase the production of biomethane. However, it may be hard to achieve a profitable system. The use of by-products, in particulate use of oxygen is important to improve profitability of the system. Installing solar power also increases the profitability. To achieve a profitable system, a selling price of oxygen at least 0.4 EUR/kg must be possible as well as a reduction in investment costs of biological methanation.

Data regarding investment costs for biological methanation, oxygen price and also heat price has been inadequate, which may have an effect of the results for the scenarios. Further research with regards to the investment costs of biological methanation needs to be conducted.

There is many more aspects, which may increase the profitability, that can be investigated. The use of oxygen can be investigated in more detail, in particularly if using the oxygen at the nearby wastewater plant can increase the profitability. Since the investment costs of biological methanation is high, using catalytic methanation instead could also be investigated.

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Abbreviations

AEL Alkaline Electrolyser

BM Biological methanation

BoP Balance of plant

CH_4 Molecular formula for methane

CO_2 Molecular formula for carbon dioxide

CAPEX Capital expenditure

CHP Combined Heat and Power

EUR Currency code for euro

h Hour

H_2 Molecular formula for hydrogen

H_2O Molecular formula for water

HVO Hydrogenated Vegetable Oil

K Kelvin

kg kilogram

KOH Molecular formula for potassium hydroxide

kW kilowatt

kW_{el} kilowatt electricity, used as rated power for the electrolyser and methanation

kWh kilowatt hour

LCOE Levelised Cost of kg methane

m^3 cubic meter

MW megawatt

MWh megawatt hour

NCF Net cash flow

Nm^3 Normal cubic meter, standard unit for volume of gases at a temperature of 0 °C and 1 atm

NPV Net present value

O_2 Molecular formula for oxygen

OPEX Operational expenditure

PEMEL Polymer Electrolyte Membrane Electrolyser

PTES Pit Thermal Energy Storage

SE3 Electricity price area 3 in Sweden

SOEL Solid Oxide Electrolyser

tons 1000 kg

TTES Tank Thermal Energy Storage

VAT value added tax

WGTES Water-Gravel Thermal Energy Storage

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1 Introduction

The Swedish government has set the goal that 100% of the produced electricity should be from renewable sources by 2040[1]. Renewable energy sources such as wind and solar are variable and electricity production depends on the weather conditions[2]. In energy systems with a high percentage of electricity produced from renewable energy sources, this can result in a mismatch between demand and supply which in turn results in fluctuations in the frequency on the electric grid. However, the electric grid must maintain a constant frequency[3]. Therefore, the production must be matched with the consumption to keep the frequency balance on the grid[4]. Today, the balance is mostly maintained by increasing or decreasing the amount of electricity produced from hydro power[5].

The incentive behind power-to-X, which power-to-methane is a part of, is to offer an alternative solution for maintaining the balance of the electric grid based on the price of electricity. The electricity price varies over time depending on the supply versus demand for electricity[2]. When the electricity price is low more electricity is available than the demand. Power-to-X uses the low price electricity to produce other energy carriers such as hydrogen or methane, thus using the excess electricity and balancing the grid. The produced energy carriers can be used directly in other applications, for example as fuel for vehicles. They can also be stored and used in a combined heat and power plant to produce electricity at times when the electricity price is high.

1.1 Background

Power-to-X is a new technology and is currently at a very early stage of commercialisation [6]. Power-to-methane is a type of power-to-X system, where the electricity is first converted into hydrogen with the help of an electrolyser. In a further step, hydrogen(H_2), and carbon dioxide(CO_2), are converted into methane(CH_4), a process which is called methanation. For power-to-methane, only a limited amount of pilot and demonstration plants exist[6]. However, both electrolyser and methanation are mature technologies that are already being used in industrial processes[6].

A difficulty with power-to-methane, as with many new technologies, is to achieve a profitable system. Both electrolyser and methanation, as well as gas storage, have high investment costs[7]. Optimizing the design and operation of the system with regards to the demand for methane and the availability of low price electricity can increase the profitability of the system. Developing a model of the system is necessary to optimize the design and operation.

The profitability of the system also depends on the dynamics of the energy system at the location where the power-to-methane system is implemented. Therefore, it is relevant to conduct a case study for a specific location. For this report, Uppsala was chosen as location for the case study.

A biogas plant already exists in Uppsala, where biogas (CH_4/CO_2) is produced from organic household and slaughterhouse waste and the upgraded biomethane (CH_4) is sold to the local bus transport company[8]. Currently, the CO_2 produced in the digestion process is not used. Since power-to-methane needs a source of CO_2, it favourably to implement the power-to-methane system at the biogas plant. Thereby, taking advantage of the unused CO_2.

In Uppsala, the local buses started to use biomethane as fuel 1996[9]. Since than, the amount of biomethane used has increased. Currently, 12.6% of the total kilometer driven by the local and regional buses during one year is driven using biomethane as fuel [10]. While the local buses are driven mostly on fossil-free fuel (biomethane, electricity and HVO), the regional buses are driven on natural gas[11]. Currently, the regional buses and the city buses use different bus depots and the infrastructure to fuel with biomethane is only available at the bus depot for the city buses[12]. A new bus depot is currently being built and when it is taken into use both the city buses and the regional buses will use the same bus depot. Then it will be possible to fuel the regional buses with biomethane[11], which is likely to increase the demand for biomethane.

The deployment of power-to-methane at the biogas plant in Uppsala could contribute to stabilizing the electricity grid and at the same time produce more biomethane which can be used as fuel for the local and regional buses. As the process also produces heat, the feasibility of recovering this thermal energy and its most appropriate use is also of interest in order to reduce the production costs.

1.1.1 Previous studies

In 2016, SWECO conducted a pre-study regarding hydrogen production in Uppsala[13]. This pre-study was conducted in cooperation with Uppsala Kommun, Vattenfall AB and Uppsala Vatten och Avfall. In the pre-study, three cases were investigated, one of them was the case of a power-to-methane system integrated into the current biogas plant owned by Uppsala Vatten and Avfall. A 5 MW electrolyser was combined with biological methanation, due to its flexibility, and the economic performance was calculated. With the assumption that it was possible to get the investment costs subsidized with 50 %, the total investment costs were calculated to 4.37 million EUR[13] . This resulted in a net cash flow, an economic parameter indicating the annual revenues, of 700.000 EUR/a [13] . According to the pre-study, 59 % of the total revenues came from selling biogas and 37 % of the total revenues came from selling oxygen. The revenues from selling heat only accounted for 3% of the total revenues. The heat was sold during the whole year to a price of 9.51 EUR/MWh. Based on the result of SWECO's pre-study, it would be interesting to investigate if storing the heat in a heat storage during summer and selling the heat during winter could increase the profitability of the system. Seeing as the price of heat is significantly higher during winter.

Out of the three cases investigated in the pre-study, SWECO regarded power-to-methane as the most interesting case and this was the case that SWECO recommended for further studies.

A feasibility study about power-to-gas in Gotland was conducted in a report from Energiforsk[14]. In this study, six cases where considered, five of these were with biological methanation and one was with catalytic methanation. The size of the electrolyser varied between 1.5 MW, 3 MW and 8 MW. As in the pre-study from SWECO, 50 % subsidization of the investment costs was assumed. For economic performance, Energiforsk used internal rate of return as parameter. The case with a 3 MW electrolyser within the area of a wind park yielded the highest internal rate of return. The case with a 1.5 MW electrolyser in combination with biological methanation yielded an internal rate of return of 4 %, at future prices. Calculations with different electricity prices showed that an electricity price of 27 EUR/MWh or lower was needed to achieve a positive internal rate of return. According to the authors, a well-designed plant where the by-products are sold has the potential to become profitable. If it is possible to receive a 50 % subsidization of the investment costs as well as tax relief on biogas.

1.2 Purpose

The aim of this case study is to investigate how a power-to-methane system can be integrated into the already existing biogas plant in Uppsala to increase the production of biomethane, to be used as fuel for the local bus fleet, as well as to investigate what is required to make the system economically profitable. Another aim is to investigate how different options affect the profitability of the system. Those options are:

- Use of the by-product, heat and oxygen
  This option was chosen since previous research has indicated that the use of by-products are important to achieve a profitable system. Using by-products more cost efficiency might increase the profitability of the system.

- Use of solar power
  This option was chosen since it might be difficult to get permission to install an energy consuming plant in Uppsala. In addition, previous research has shown that electricity cost is the main operating cost for power-to-methane. Adding solar power might reduce the cost of electricity.

To assess the economic performance of the system, a dynamic model will be created by integrating an economic model already developed at the Department of Energy and Technology of SLU with collaborators with an already existing dynamic model, as well as elaborate both models further.

To assess the economic performance of the power-to-methane system, four economic parameters were used capital expenditure(CAPEX), levelised cost of kg methane(LCOE), net cash flow(NCF) and net present value(NPV).

1.3 Research questions

- How can a dynamic model be constructed to simulate the economic performance of a power-to-methane system in a reliable way?
- How can a power-to-methane system be designed and operated in a way to provide fuel according to the demand of a bus fleet in Uppsala?
- How does the use of by-products and solar power affect the profitability of the system?
- How do changes in investment cost of methanation and selling price of oxygen affect the economic performance? How can changes in these parameters, together and combined with other adjustments, make the system profitable?

1.4 Boundaries

This report is written as a degree project in Energy System Engineering within a limited amount of time, therefore some boundaries and limitations need to be set. The profitability of the system will only be investigated with regards to the different options states in section 1.2. Additional options affecting the profitability of the system will be discussed in section 6.4 but not regarded in the simulations. In addition, the calculations and simulations will only be conducted for one year.

2 Power-to-X

Power-to-X is the name for a collection of systems, converting excess electricity into other energy carriers for example hydrogen, methane or heat. The main incentive behind power-to-X is that electricity is difficult to store. By converting the electricity into other energy carriers the energy can be stored easier. Figure 1 shows an overview of the different types of power-to-X system that exists[15].

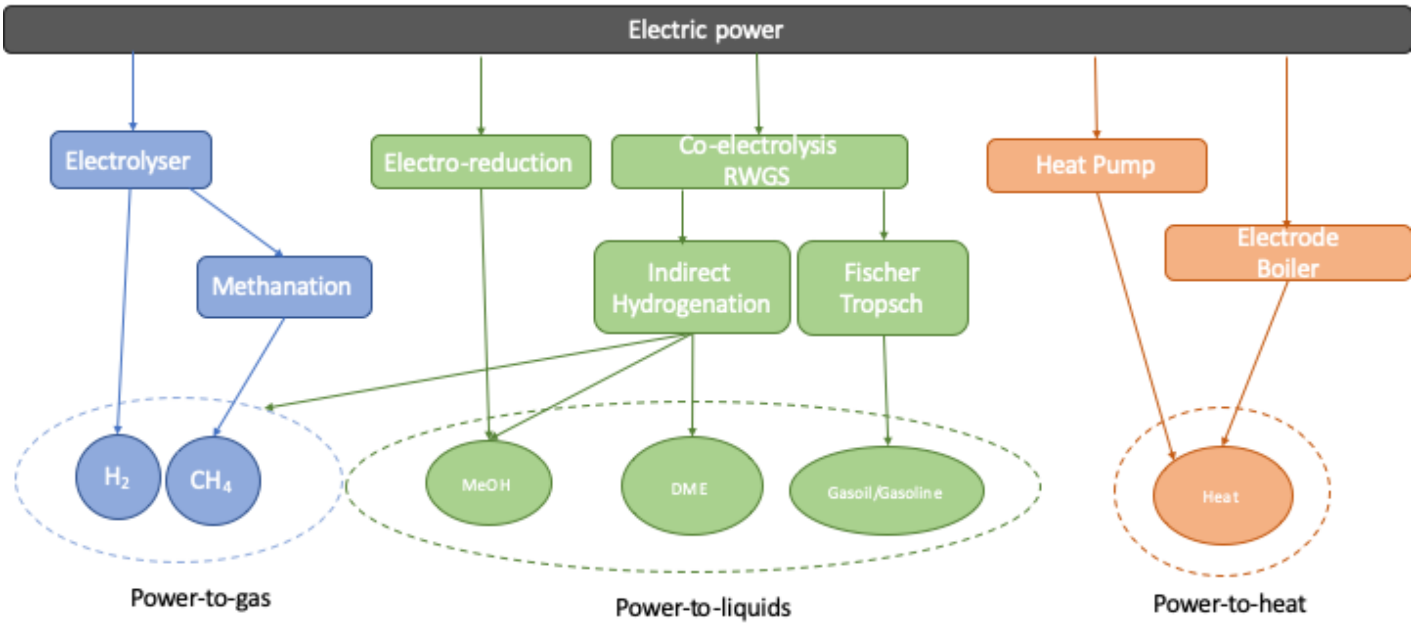

Figure 1: Overview over different concepts within Power-to-X

The produced liquids and gases can be used for mobility. If a natural gas grid exists, the produced methane can also be injected into this grid. The produced heat in power-to-heat can be used for heating and also injected into the district heating grid if such a grid exists.

2.1 Pilot Plants

Most of the development is taking place in Europe, although there are some development taking place in other parts of the world[6]. Most projects are based on power-to-hydrogen, even though power-to-methane is dominating in Denmark. The pilot plant most similar to the system that will be modeled in this case-study is the BioCat project in Denmark. In the BioCat project, a 1 MW electrolyser is combined with biological methanation[14]. The BioCat-project has shown that biological methanation can produce gas with gas grid quality. That is a methane content of more than 97 %, less than 2 % hydrogen as well as less than 1 % CO_2 and less than 5ppm H_2S[14].

2.2 Power-to-methane

In power-to-methane, the electricity is converted through electrolysis into hydrogen and in a second step hydrogen is converted to methane through methanation[6]. The different parts will be explained in detail in the coming sections. The produced methane can be used in the same way as natural gas and biomethane since they are the same chemical compound(CH_4). Methane can be feed into the natural gas grid, used as fuel for buses or burned in a combined heat and power plant(CHP) to generate heat and electricity. In this case study, the methane will be used as fuel for buses since methane is already used as fuel for buses in Uppsala, where the case study is taking place.

2.3 Electrolyser

The basis of an electrolyser is to produce hydrogen by splitting water into hydrogen and oxygen with the use of electricity. There are three main technologies for the electrolysis of water: alkaline electrolysis, polymer electrolyte membrane electrolysis and solid oxide electrolysis[16].

2.3.1 Alkaline Electrolyser

The alkaline electrolyser(AEL) consists of an anode and a cathode that are separated by a membrane and immersed in a liquid electrolyte[16]. The electrolyte usually consists of a 25-30 % aqueous KOH-solution(potassium hydroxide)[16]. At the cathode, water is consumed and hydrogen is produced by reaction 1. At the anode, water and oxygen are produced by reaction 2[16].

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{1}$$

$$2OH^- \rightarrow 0.5O_2 + H_2O + 2e^- \tag{2}$$

The overall reaction then becomes:

$$H_2O \rightarrow H_2 + 0.5O_2 \tag{3}$$

The load flexibility varies between manufacturers. Some electrolyser can operate with 10-110% of nominal power. However, the most occurring load flexibility is 20-100% of nominal power[16]. When no production is needed, the electrolyser goes into either cold or warm standby. During warm standby, the electrolyser keeps its working temperature and can go from standby to production in 1-5 minutes. From cold standby, the electrolyser needs to be heated up before starting to produce hydrogen. Because of this, the start-up time from cold standby to production is 1-2 hours[16].

AEL is a low temperature electrolyser operating at temperatures between 60-90 °C[16].

2.3.2 Polymer Electrolyte Membrane Electrolyser

The polymer electrolyte membrane electrolyser(PEMEL) consists of a proton exchange membrane separating two half-cells[16]. The electrodes are usually mounted directly on the membrane. The following reaction takes place at cathode respectively anode[16].

$$2H^+ + 2e^- \rightarrow H_2 \tag{4}$$

$$H_2O- \rightarrow 0.5O_2 + 2H^+ + 2e^- \tag{5}$$

The overall reaction then becomes the same as for AEL:

$$H_2O \rightarrow H_2 + 0.5O_2 \tag{6}$$

Most manufacturers do not provide any information regarding load flexibility. However, the load flexibility that is provided by a few manufacturers states a load flexibility of 0-160% of nominal power[16].

As for AEL, PEMEL goes into cold or warm standby when no production is needed. PEMEL has shorter start-up times than AEL, going from cold standby into operation in 5-10 min[16].

2.3.3 Solid oxide electrolysis

Solid oxide electrolyser(SOEL) is currently in the research stage. Although one company offers small electrolyser, SOEL is not considered commercially available[16]. Therefore, SOEL will not be considered or explained in this report.

2.4 Methanation

Methanation is the second step of the power-to-methane process where hydrogen from the electrolyser is converted together with carbon dioxide into methane. There are two technologies for methanation catalytic methanation and biological methanation.

2.4.1 Biological methanation

In biological methanation(BM), hydrogen and carbon dioxide are converted into methane by the use of methanogenic microorganisms[6]. The reaction that takes place is[17]:

$$4H_2(g) + CO_2(g) \rightarrow CH_4(g) + 2H_2O(l) - 253kJ/molCH_4 \tag{7}$$

Like the electrolyser, the methanation reactor goes into cold or warm standby when no production is needed[17]. The biological methanation is very flexible to part-load operation and can go from cold standby into operation within seconds[13]. Biological methanation is also insensitive to impurities in the CO_2 stream[18].

There are three processes for biological methanation: in-situ process, ex-situ process and hybrid process[19].

In the in-situ process, hydrogen is injected into the biogas reactor. Inside the reactor, the CO_2 from the anaerobic digestion reacts with the injected hydrogen, producing additional methane[19]. The advantage with the in-situ process is that no extra reactor needs to be built, thereby reducing the investment costs. The disadvantage with the in-situ process is that a too high injection of hydrogen can inhibit the anaerobic digestion in the biogas reactor[19].

In the ex-situ process, hydrogen and CO_2 from the anaerobic digestion are converted into methane in an external reactor. This process has the advantage that it does not interfere with the anaerobic digestion and additional sources of CO_2 can be used[19]. The disadvantage is that it requires an additional reactor and thereby increase the investment costs.

The hybrid process is a combination of the in-situ process and the ex-situ process, where a part of the hydrogen is injected into the biogas reactor and a part of the hydrogen is injected into an external reactor[19]. Thereby, the investment costs are partially reduced compared to the ex-situ process and the risk of interfering with the anaerobic digestion is also partially reduced compared to in-situ.

2.4.2 Catalytic methanation

Catalytic methanation(CM) is a thermochemical process operating at high temperatures between 200-700°C and at high pressure[18]. The high temperature increases the possibility of using waste heat. Methane is produced through the same reaction as the previous section.

Catalytic methanation works best with continuous operation as load changes may induce runaway heating or cooling of the reactor. To avoid such issues a minimum load of 40 % needs to be maintained[18].

Catalytic methanation also requires a high purity CO_2 stream. The biogas produced from a biogas plant does not meet the required purity and therefore must be cleaned before use in catalytic methanation[18], thereby adding extra investment costs.

2.5 Heat storage

While waste heat from the electrolyser is produced over the whole year, the demand for heat is higher during winter. Because of this, the price for heat is higher during winter compared to the summer[20]. Storing the heat during summer, possibly even spring and autumn, and selling the heat during winter could possibly increase the revenues from the system.

However, storing thermal energy for long time periods is associated with high thermal losses. As much as 30 % of the thermal energy can be lost during storage[21]. To reduce the losses, the storage needs to be sufficiently insulated which causes the investment costs to rise. Guelpa [21] states that the investment cost for heat storage varies between 30 - 500 EUR/m^3.

There exist different types of heat storage, those will be explained in the next section.

2.5.1 Types of heat storage

Both short-term and long-term heat storage exist but this report will be focused on long-term heat storage, also called seasonal heat storage. The seasonal heat storage that exists is Pit Thermal Storage(PTES), seasonal Tank Thermal Energy Storage(TTES) and Water-Gravel Thermal Energy Storage(WGTES)[22]. TTES and PTES both have water as filling material whilst WGTES has a mixture of water and gravel as filling material. However, water is most commonly used as filling material[22]. Because of this, only TTES and PTES were considered for this report.

TTES consists of a constructed basins that is partially or completely elevated from the ground. Whilst PTES consists of sealed pits in the ground without any structural elements[22]. Because of this, the ground must have good stability and no presence of groundwater[22]. PTES, therefore, requires certain geological conditions whilst TTES is more flexible with regards to geological conditions.

Regarding already existing seasonal heat storage, TTES is the most commonly used technology, however, PTES dominates when it comes to the total installed storage volume since PTES tends to have larger volume[22]. A review of already existing seasonal heat storage shows that PTES tends to have lower investment costs (30 - 400 EUR/m^3) than TTES. TTES has an investment cost between 110 - 475 EUR/m^3 [23].

2.5.2 Price for waste heat

As mentioned in section 2.3.1 and 2.3.2, AEL and PEMEL normally produce waste heat at around 60°C. This temperature is too low to use the waste heat directly in the district heating since the district heating grid normally has a temperature of 90°C[20]. However, a new project from Vattenfall called "Samenergi" investigates possible options for using low-temperature waste heat from companies [20]. One option is to use waste heat to heat the return water from the district heating. This was the option that SWECO used in the previous pre-study[13]. Another option is to use the waste heat in low-temperature district heating. Low-temperature district heating is a new district heating system where water at temperatures around 60°C is used instead of water at 90°C[24]. In this case study, the details of using the waste heat were not investigated but it was assumed there would be a market for low-temperature waste heat in the future.

An average price over the year for waste heat at 90°C was given by Vattenfall. Because the waste heat in this case study only was at 60°C, a lower price was used for the calculations.

The selling price of heat, to private customers, was around 8.74 EUR/MWh during summer and around 77.33 EUR/MWh during winter for 2019[25]. However, there was no available information regarding the price of selling waste heat to Vattenfall during summer and winter.

2.6 Electricity

Electricity from the grid was mainly used as input to the electrolyser. In some scenarios, electricity produced from solar power was also used.

2.6.1 Purchased Electricity

The cost of purchased electricity is the main operating cost for a power-to-gas system [26]. For the system in this case study, electricity is purchased both from the spot market and at regular market prices. The electricity purchased from the spot market was used for the electrolysis whilst for standby and safety equipment electricity purchased at regular market prices was used. The total price paid for electricity consists of the spot price or price at the regular market, as well as a grid fee [14].

2.6.2 Solar Power

Currently, the electric grid in Uppsala and the region around Uppsala lack power capacity some hours of the year[27]. Since companies need permission from the grid owner to establish a new energy-consuming plant the lack of power capacity may hamper the implementation of power-to-methane in Uppsala. A solution to this problem could be to install solar power to produce electricity, this way the amount of electricity needed from the grid would decrease. At times when no production is needed electricity from solar power could also be sold to the grid, giving extra revenues.

The cost of electricity produced from solar power can be found in Figure 2[28]. The cost is expected to decrease in the future.

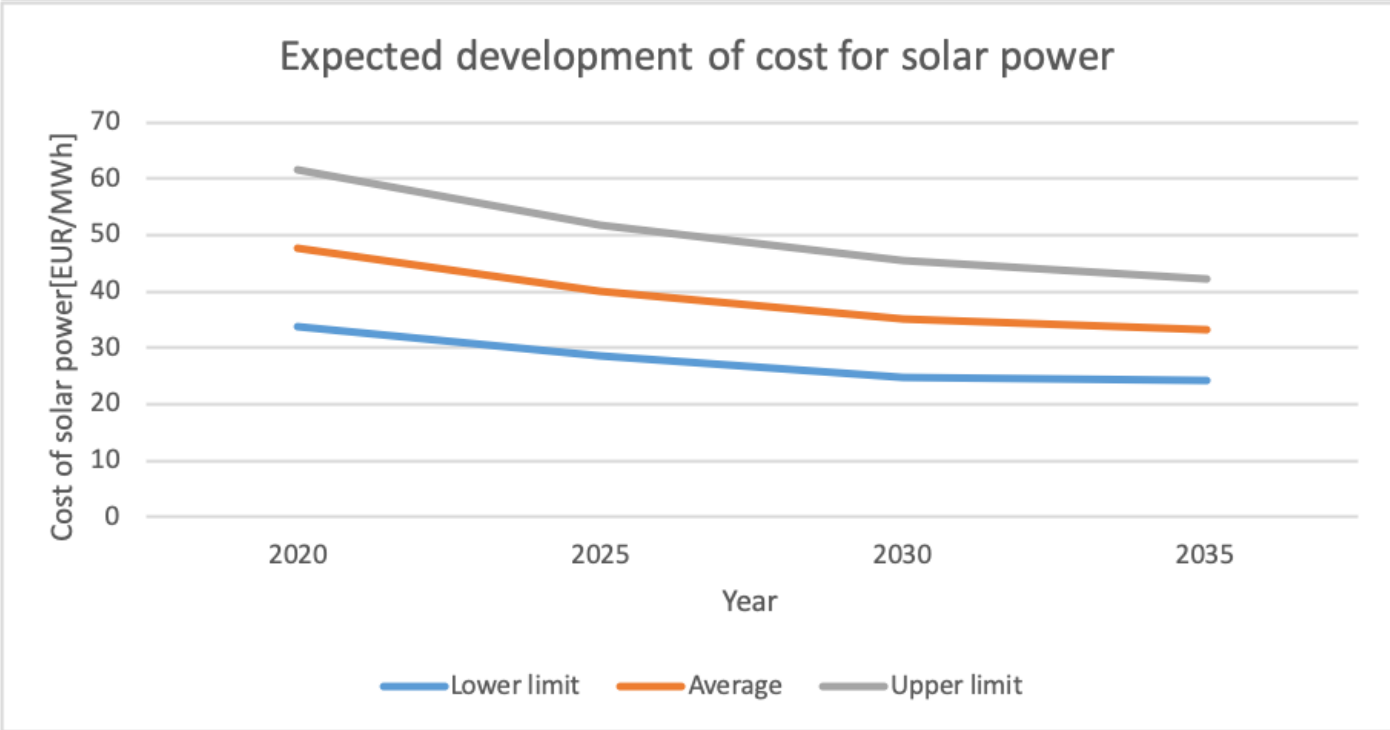

Figure 2: Expected development for cost of solar power.

2.7 Investment costs for methanation and electrolyser

Power-to-methane is currently in the early stage of commercialization and it is likely that the capital expenditure(CAPEX) for both electrolyser and methanation will decrease in the future. Figure 3 shows the expected development of CAPEX for AEL and BM between 2020 and 2050[7]. Both CAPEX for biological methanation and alkaline electrolyser are expressed in EUR/kW_{el}, where kW_{el} is referring to the nominal power of the electrolyser.

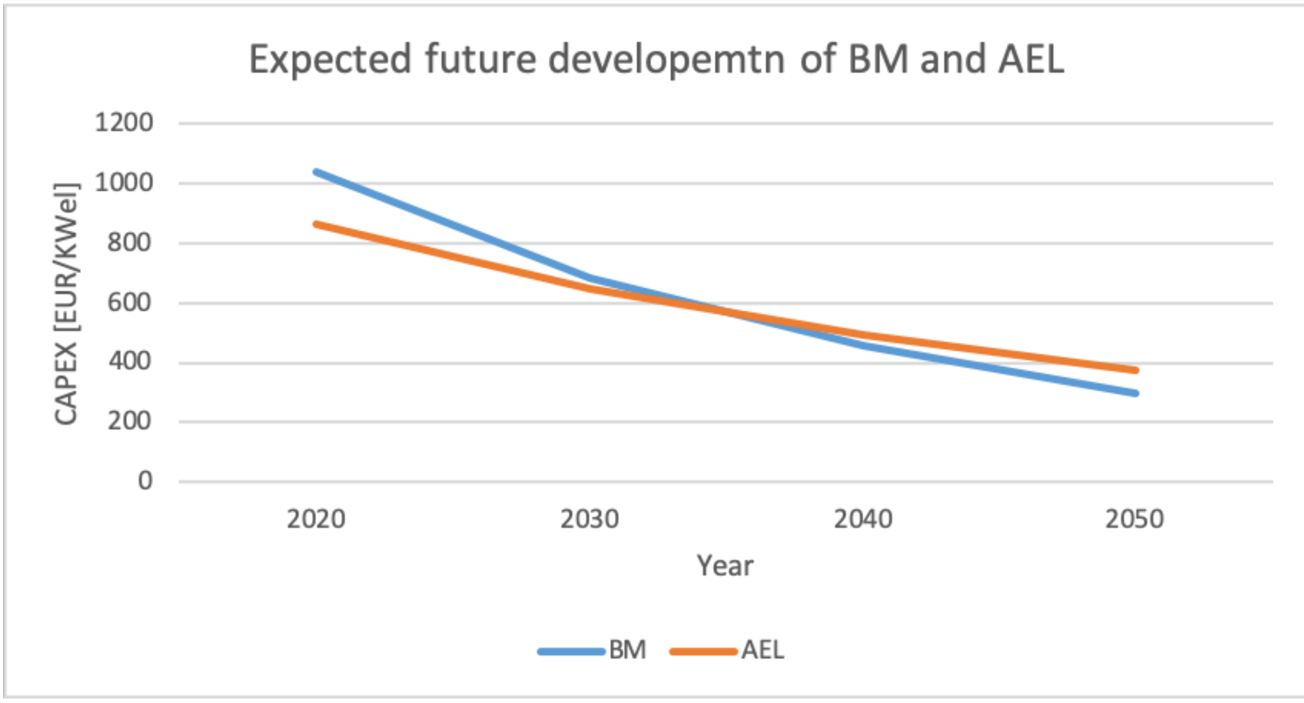

Figure 3: Expected development of CAPEX for biological methanation and alkaline electrolyser.

The development of CAPEX for biological methanation and alkaline electrolyser in Figure 3 are given by Thema et al. [7], who states that the values for biological methanation are uncertain. In addition to the uncertainty in the development of CAPEX, the value of the current CAPEX also varies between different sources. McDonagh et al. [18] uses a value of 160 EUR/kW_{el} for catalytic methanation, whilst Thema et al. [7] states that the value for catalytic methanation is around 700 EUR/kW_el. Both these values do not include additional components apart from the reactor, such as pumps and compressors, usually referred to as balance of plant(BoP). German Energy Agency(DENA)[29] is presenting the values 400-1230 EUR/kW_{el} for catalytic methanation and 400-1980 EUR/kW_{el} for biological methanation, predicting costs down to 200-400 EUR/kW_{el} in the future. However, balance of the plant is not mentioned. Leeuwen and Zauner [30] discusses the difference in CAPEX between different sources. Briefly, the values vary significantly between sources ranging from around 275 EUR/kW_{el} up to 2000 EUR/kW_{el}, including balance of the plant. The presented values are also for different sizes of electrolyser, most sources are agreeing that a large system will benefit from scale effect reducing the cost per kW_{el}.

Only a few demonstration and pilot plants exist and most of them have high investment costs. For example, a demonstration plant in Switzerland has a total investment cost of around 2000 EUR/kW_{el}, including balance of the plant. This corresponds to the upper limit stated by Leeuwen and Zauner [30]. In a report regarding the BioCat-project in Denmark Electrochaea.dk ApS [31] estimated the future CAPEX for biological methanation to be around 1460 EUR/kW_{el}, including balance of the plant.

In addition, the data regarding the lifetime of the biological methanation reactor is lacking. McDonagh et al. [18] uses a replacement cost of 80 % of CAPEX for catalytic methanation with a lifetime of 15 year whilst Thema et al. [7] does not mention replacement at all. This is also the case for DENA[29]. Leeuwen and Zauner [30] mention that none of the review literature gives estimates for the lifetime of the methanation reactor.

Concerning the electrolyser, different sources state similar values. McDonagh et al. [18] give a value of 830 EUR/kW_{el} as CAPEX while Thema et al. [7] give a value of around 860 EUR/kW_{el}, both values do not include balance of the plant. DENA [29] states that the investments cost ranges from 800 - 1500 EUR/kW_{el} but do not mention of those values are with or without balance of the plant.

2.8 Other economic parameters

To determine the economic performance of a power-to-methane system, different economic parameters can be used. Commonly used parameters are total capital expenditure(CAPEX), levelised costs of kg methane(LCOE), net cash flow(NCF) and net present value(NPV). Those will also be used in this case study. The calculations of the economic parameters will be explained in the coming sections.

2.8.1 Costs and revenues

A number of costs are linked to the system. Those can be seen below.

- Capital expenditure(CAPEX)
- Operational costs(OPEX)
- Electricity costs
- Cost for solar power(if solar power is used)

The system yields a number of revenues, those can be seen below.

- Sales of CH_4
- Sales of waste heat (if heat is sold)
- Sales of O_2 (if O_2 is sold)
- Sales of excess solar power (if solar power is used)

With the costs and revenues of the system, the economic parameters are calculated.

2.8.2 Capital expenditure(CAPEX)

CAPEX represents the investment costs for the project, both investments made during the commission of the plant but also necessary replacements during the plant's life span. In the case of the power-to-methane system, the investment cost during the commission consists of the cost of the electrolyser, methanation reactor and other smaller components that are necessary for the operation of the electrolyser and methanation reactor, referred to as balance of the plant(BoP). In addition, the investment costs for the methane storage and heat storage are also added to CAPEX of the first year.

The life span of the plant is estimated to be 30 years. During this time both the electrolyser and methanation reactor need to be replaced. The electrolyser is assumed to be replaced at year 8 and 16 of operation, and the replacement cost of the electrolyser is therefore added to CAPEX for year 8 and 16. The methanation reactor is assumed to be replaced once, in year 15 of operation. Therefore the replacement cost of the methanation reactor is added to CAPEX at year 15.

Both the heat storage and methane storage is assumed to last for the whole life span of the project.

2.8.3 Levelised cost of kg methane (LCOE)

LCOE represents the break-even selling price for the produced methane and can be used to compare different energy carriers. LCOE is defined as in equation 8[18].

$$LCOE = \frac{\sum_{i=0}^{n} \frac{Cost\ in\ year\ i}{(1+Discount\ rate)^i}}{\sum_{i=0}^{n} \frac{kWh\ of\ gas\ produced\ in\ year\ i}{(1+Discount\ rate)^i}} \tag{8}$$

In equation 8, the costs are divided by the produced methane in kWh. In this case study, the costs will be divided by the produced methane in kg to give the levelised cost of kg methane.

2.8.4 Net cash flow (NCF)

NCF is the difference between annual revenues and costs. For a power-to-methane system, it can be calculated as in equation 9[32].

$$\mathrm{NCF}_y = (P * CH_4 - \mathrm{OPEX}_y) \tag{9}$$

In this equation, P stands for the selling price of methane, CH_4 represents the produced methane and y represents the year for which the net cash flow is calculated. For the system in this case study heat, oxygen and excess electricity from solar power will also be sold. Thereby giving additional revenues that need to be added to the calculation of NCF. Therefore, NCF in this case study was calculated by equation 10.

$$\mathrm{NCF}_y = (CH4\_sales + Heat\_sales + O2\_sales + Revenues\_Solarpower - \mathrm{OPEX}_y) \tag{10}$$

Where $CH4\_sales$, $Heat\_sales$, $O2\_sales$ and $Revenues\_Solarpower$ are the revenues from sales of the three products from the process and excess electricity from solar power. In this case study, NCF_y is assumed to be equal for all years.

OPEX consists of the operational costs and can be calculated by equation 11[18].

$$\mathrm{OPEX}_y = (OPEX\_BM + OPEX\_AEL + Electricity\_cost + H_2O\_cost) \tag{11}$$

In this case study, solar power was also used and the cost of solar power therefore need to be added to the calculation of OPEX. This resulted in OPEX being calculated as in equation 12.

$$\mathrm{OPEX}_y = (OPEX\_BM + OPEX\_AEL + Electricity\_cost + H_2O\_cost + Cost\_solarpower) \tag{12}$$

The operational cost consists of four parameters: cost of producing solar power, operational costs connected to the electrolyser and methanation, cost of used water and cost of electricity purchased from both the spot market and at regular market prices. Like NCF, OPEX is assumed to be equal for all years.

2.8.5 Net present value(NPV)

NPV is defined as the difference between the NCF and CAPEX, expressed in the present value. NPV is calculated by equation 4 [32].

$$NPV = -CAPEX + \sum_{y=1}^{n} \frac{NCF_y}{(1+k)^y} \tag{13}$$

In this equation, y stands for the year and k stands for the discount rate. NCF_y is the net cash flow in year y and is calculated by equation 2 in the previous section.

3 System description

In this case study, the power-to-methane system will be integrated into the current biogas plant in Uppsala. The reason for this is that power-to-methane needs a source of CO_2. It is preferred to use a biological source of CO_2 to produce a sustainable alternative to fossil fuels. In this section, the current system will be explained as well as the integrated system.

3.1 The biogas plant

Uppsala Vatten och Avfall is currently operating a biogas plant located at Kungsängens gård in Uppsala. The biogas plant was built in 1996 and has been expanded over the years[8]. Both organic household waste and slaughterhouse waste are being used as substrate for the reactors[8]. Recently, Uppsala Vatten increased production by taking a new reactor into use. Now the biogas plant has the capacity to treat 250 tons of food waste and organic waste per day. Currently, an average of 130-135 tons of organic waste is treated per day[33].

After being pre-treated, where plastic bags and other impurities are removed, the organic waste goes through hygienisation where it is heated up to 70°C for one hour[8]. The heat is supplied by steam from burning wood pellets[33].

Figure 4: The current biogas plant in Uppsala, with the reactors to the right in the picture.

The pre-treated and hygienised organic waste is then undergoing anaerobic digestion in the reactors, at a temperature of 52°C[8]. Figure 4 shows the biogas plant from the southwest side. Two of the reactors as well, as the gas storage, can be seen on the right side of the picture. During the anaerobic digestion, biogas with a gas content of 65 % methane and 35 % CO_2 is produced. Afterward, the CO_2 is removed from the biogas by a water scrubber[8]. CO_2 is released into the atmosphere whilst the produced methane is compressed to 280 bar and stored at the filling stations[33]. Methane is also produced at the nearby wastewater plant[8]. The produced methane is used as fuel for 77 buses and around 500 cars[33].

3.2 Fuel for the buses

In Uppsala, the regional and local buses use hydrogenated vegatable oil(HVO), electricity, biomethane and natural gas as fuel[11]. Table 1 shows the use of biomethane and natural gas for the year 2019[10]. Currently, the buses in the region of Uppsala use two bus depots. The local buses use a bus depot located at Kungsgatan whilst the regional buses use a bus depot in Fyrislund[12]. The produced biomethane is transported through pipelines to the bus depot at Kungsgatan. Today, it is not possible to fuel with biomethane at the bus depot in Fyrislund. Because the municipality wishes to use the area at Kungsgatan for other purposes, a new bus depot for the local buses is currently being built next to the bus depot for the regional buses[12]. When the new bus depot is taken into use, it will be possible to fuel both the local buses and the regional buses with biomethane.

Table 1: Demand of fuel for the local and regional buses, in ton and 1000 Nm^3

Fuel	Demand (ton)	Demand (1000 Nm^3)
Biomethane	2 470	3 430
Natural gas	2 530	3 520
Total	5 000	6 950

In 2019, 4 470 000 Nm^3 biomethane was produced in the biogas plant and the wastewater plant together[34]. The production was around 1 000 000 Nm^3 higher than the demand of the buses. The excess biomethane was burned and the heat was used in the process. However, selling the biomethane yields higher revenues than burning it. Therefore, the biomethane would not be burned if there would be a demand for it.

To supply the regional buses driven with natural gas in 2019 with biomethane in the future, an additional 2 480 000 Nm^3 of methane needs to be produced. This accounts for an increase in production with 55 %.

The demand for fuel is varying over the day and also over the week depending on the operation of the buses. Figure 5 shows the fuel demand throughout one week.

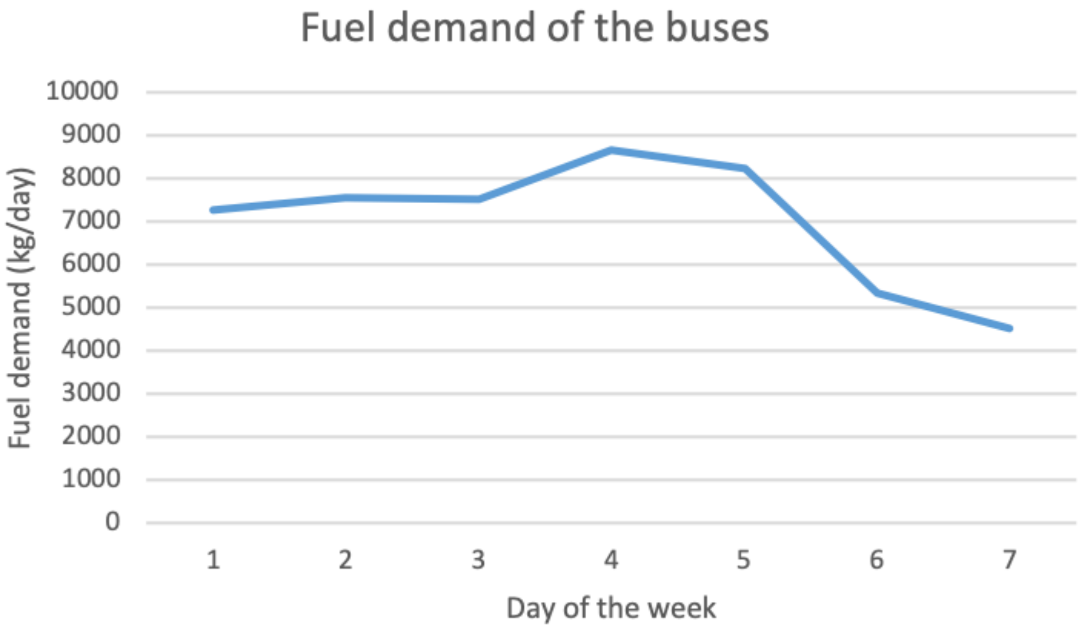

Figure 5: Demand of fuel throughout the week starting on day 1(monday) until day 7(sunday). The data was provided by Uppsala Vatten and expressed in kg/day.

In Figure 5 it can be noted that the demand of fuel is lower on saturday and sunday. This is because fewer buses are driving during the weekend.

3.3 Available CO2

The available CO_2 was calculated from the data of the production of biomethane provided by Uppsala Vatten to 2.4 Million Nm^3/a[34]. Based on the available CO_2 the hydrogen production needed to be adjusted.

3.4 Power-to-methane

To integrate power-to-methane into the current biogas plant an electrolyser and a methanation reactor as well as other smaller components, usually referred to as balance of plant, need to be added. For both electrolyser and methanation, multiple technologies can be used as stated in section 2. The chosen technologies can be seen below:

- Electrolyser - Alkaline Electrolyser
- Methanation - Biological Methanation
- Heat Storage - Tank Thermal Energy Storage

An alkaline electrolyser was chosen since this technology is more well-established than PEMEL and SOEL.

For methanation, biological methanation was chosen since it handles part-load operation better than catalytic methanation. Especially, biological methanation can handle a lower load than catalytic methanation, which makes it possible to use a larger amount of the electricity produced from solar power. Biological methanation can also handle impurities in the gas better than catalytic methanation. The disadvantage of biological methanation is that the investment costs are higher.

As mentioned in section 2.4.1 there are three ways to integrate biological methanation into the biogas plant: in-situ, ex-situ and hybrid. The ex-situ process was chosen despite it being more expensive. Both in-situ and hybrid risk to affect the anaerobic digestion in the biogas reactor, a risk that is removed by choosing the ex-situ process.

For heat storage, a Tank Thermal Energy Storage was chosen since this technology is more flexible when it comes to geological conditions.

3.5 Size of the electrolyser

An electrolyser with a size of 1.074 MW was used, due to data of this size of electrolyser being available. In addition, it was assumed that it would not be possible to install a larger electrolyser in Uppsala, because of the shortage of power. However, a smaller electrolyser would have higher investment costs per kW which would affect the economic performance negatively.

4 Model description

To determine the economic performance of the system, a dynamic model was developed and combined with relevant data. With the dynamic model, a number of simulations were conducted to investigate different options. The result of the simulations was used to determine the design of the system as well as optimize the operation of the system. At last, the dynamic model was used to determine which conditions that are needed to achieve a profitable system in the future.

The dynamic model was based on a model developed in a previous bachelor thesis[35], combined with an economic model developed by the Department of Energy and Technology at SLU and collaborators[18]. The dynamic model was implemented in MATLAB/Simulink.

4.1 Dynamic model

Figure 6 shows a simplified overview of the dynamic model with the main components of the system implemented as either subsystems or MATLAB-functions for an easier overview. In addition to the main components, several small components such as compressors were also included in the dynamic model. Also, conversion between units was sometimes necessary to combine provided data with the dynamic model.

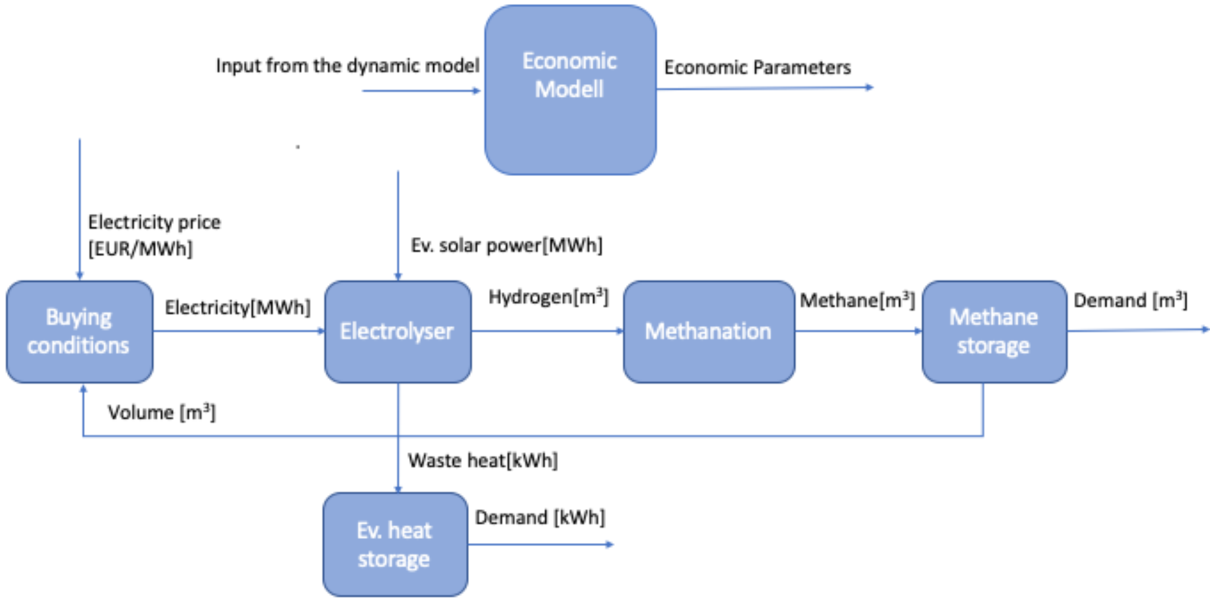

Figure 6: Flowchart of the dynamic model. The parts will be explained in detail in the text.

Collected and adjusted data was imported into the model from the MATLAB-workspace. The imported vectors and their corresponding data are presented in the list below:

$Price\_SE3\_2019$ -The electricity price(in €/MWh) for SE3, electricity price area 3 in Sweden, for the year 2019

$solar\_production$ -The produced solar power(in W) for the year 2016

$Heat\_demand$ -The heat supplied to the district heating system (in kW) during winter

$Biogas\_production$ -The biomethane produced at the biogas plant(in Nm^3/h) for 2019

$Waste\_water\_plant$ -The biomethane produced at the wastewater plant(in Nm^3/h) for 2019

$Demand\_of\_buses$ -The methane demand of the buses (in kg/h) for 2019

The economic parameters were calculated in a MATLAB-function and the result exported to MATLAB as timeseries-vectors. The economic parameters that were calculated and exported can be seen below.

$CAPEX\_A$ -Total capital expenditure(in €)

$LCOE\_kg\_A$ -Levelised cost of kg methane(€/kg CH_4)

$Revenue\_A$ -Net cash flow(in €/a)

NPV_A -Net present value(in €)

The different parts of the model will be explained in more detail in the sections below.

4.1.1 Buying conditions

In the previous bachelor thesis, electricity was purchased from the spot market when the electricity price was lower than a set limit. In this case study, the aim was to develop a dynamic model where the production of methane was controlled based on the demand of fuel. Therefore, this part of the dynamic model was redesigned. Instead of electricity being purchased based on the electricity price, electricity was primarily purchased based on the volume of the methane storage and secondly based on the electricity price. This was implemented into the dynamic model as a so-called state-flow. Figure 7 shows the state-flow that controlled whether or not electricity was purchased from the spot market. The system could be in two so-called states, either buying electricity from the spot market or not buying electricity from the spot market. Electricity was purchased either if the volume of the storage was below a set volume limit or if the electricity price was below a set price limit. If the volume of the storage was above the set limit the state-flows went into the not-buying state, that is no electricity was purchased from the spot market. The aim of the state-flow was to buy low price electricity as much as possible, whilst still fulfilling the demand of the buses.

The volume limit needed to be high enough to fulfill the demand of methane at all times, but also as low as possible in order not to buy high priced electricity. The limit for the volume was set based on a number of simulations, investigating how high the limit needed to be in order to fulfill the demand of methane at all times of the year.

The price limit for electricity needed to be as low as possible to only purchase low price electricity. At the same time, a too low limit would mean that electricity would be bought based on the volume, with the risk of buying high priced electricity to fill up the storage. The limit for electricity was determined based on the average electricity price.

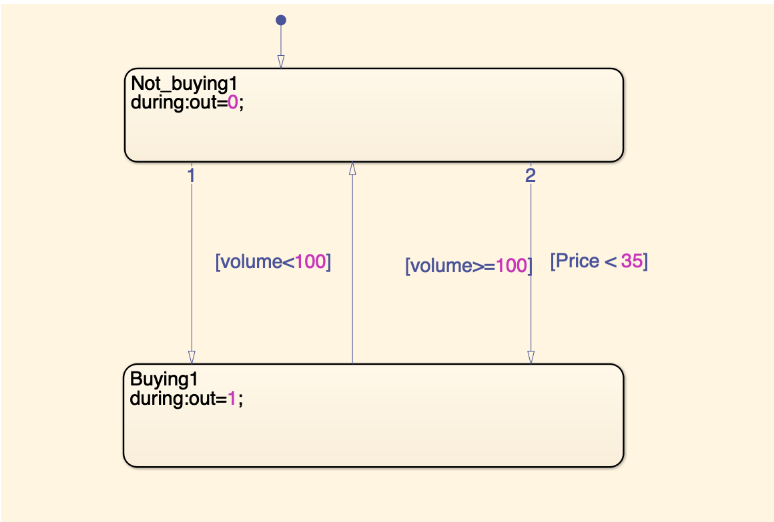

Figure 7: State-flow that controls whether the system is buying electricity from the grid or not.

This part of the dynamic model had volume of methane storage and electricity price as input to the state-flow. Output was the signal *out*, which could take the values 1 or 0. When the value was 1, electricity was purchased from the grid and when the value was 0 electricity was not purchased from the grid. The signal *out* was multiplied with the power of the electrolyser and the result was used as electricity input to the electrolyser. When solar power was used, the electricity purchased from the grid was added to the electricity produced from solar power, this will be explained in detail in section 4.1.7.

4.1.2 Electrolyser

The electrolyser was implemented into the dynamic model as a MATLAB-function with the electricity consumption for each hour as input. The electricity consumption was the result of the previous section, buying conditions. The produced hydrogen was then calculated within the MATLAB-function by equation 14. This part was developed in the previous bachelor thesis[35], in this study the MATLAB-function was controlled to make sure the results were correct. The amount of hydrogen produced was calculated by the use of data regarding the amount of power needed to produce one m^3 of hydrogen.

$$Hydrogen\_out\_m3 = (MWh\_per\_year * 1000)/(kWh\_per\_Nm3) \tag{14}$$

The MATLAB-function also calculated the produced waste heat and oxygen by equation 15 and 16.

$$waste\_heat = (MWh\_per\_year * waste\_heat\_per\_MW) \tag{15}$$

$$Oxygen\_out\_kg = (Water\_deionized\_in\_kg * 0.888093) \tag{16}$$

In equation 16, the value 0.888 was calculated based on the molar weight of oxygen, water and methane. As can be seen in equation 3 for the electrolyser in section 2.3.1, one molar of water produces 0.5 molar oxygen and 1 molar hydrogen. Because of the corresponding densities, this means that 88.8 % of the weight of water is converted to oxygen. The values used and their corresponding reference can be seen in Table 2. The full MATLAB-function can be seen in Appendix A.

4.1.3 Methanation

As the electrolyser, the methanation was implemented into the dynamic model as a MATLAB-function and the produced methane was calculated within the MATLAB-function by eqution 17-19. As with the electrolyser-function, the methanation-function was developed in the previous bachelor thesis[35] and in this case study the function was only controlled so that the results were correct. Hydrogen produced per hour(in m^3), calculated as in the previous section, electrolyser, was input to the MATLAB-function that calculated the produced methane by use of the chemical formula. In a first step the hydrogen was converted to kg, equation 17.

$$h2\_in\_kg = (h2\_in * 0.0898) \tag{17}$$

The value 0.0898 in equation 17 represents the density of hydrogen. Thereby hydrogen is converted from m^3 into kg. In the second step, equation 18, the amount of CO_2 needed is calculated based on the amount of hydrogen.

$$CO2\_in\_kg = (h2\_in\_kg * 5.458294471) \tag{18}$$

In equation 18, the value 5.5 was calculated based on the molar mass of hydrogen and CO_2. As can be seen in equation 7 for the methanation process, in section 2.4.1, the ratio between

CO_2 and hydrogen is 1/4. With the corresponding molar weight, the ratio becomes 44/8 which gives a value of approximately 5.5. In the final step, equation 19, the produced methane is calculated based on the amount of hydrogen and CO_2.

$$Methane\_out\_kg = (h2\__in\_kg + CO2\_in\_kg) * 0.308078021 \tag{19}$$

The value 0.3 in equation 19 represents the percentage of the total mass of hydrogen and CO_2 that were converted into methane. According to equation 7 in section 2.4.1 the reaction yields 1 molar methane and 2 molars of water, that is only 1/3 of the produced molar were methane. With the corresponding densities, 16/52 percentage of the total mass becomes methane which equals around 30 %. The produced methane was then converted into m^3 to be used as input to the storage. The densities used as well as the corresponding references can be seen in table 2. The whole MATLAB-function can be seen in Appendix B.

4.1.4 Heat storage

The heat storage was implemented as a subsystem, to make the overview of the dynamic model easier. A simplified flow chart of the heat storage can be seen in Figure 8. The heat storage was not part of the previous bachelor thesis and completely developed within this case study. The produced heat per hour and the heat demand, both in kW, were used as input to the subsystem, while tank volume and electricity consumption were output from the subsystem. In the heat storage, it was assumed that 30 % of the stored heat was lost due to heat losses. Because of the heat losses in the heat storage, it was assumed that the temperature of the water would drop. A heat pump was therefore used to increase the temperature of the water back to 60 °C before it was injected into the district heating grid.

The volume of the storage was set to 4000 m^3 since simulations showed that a larger volume would not be filled up by the produced waste heat.

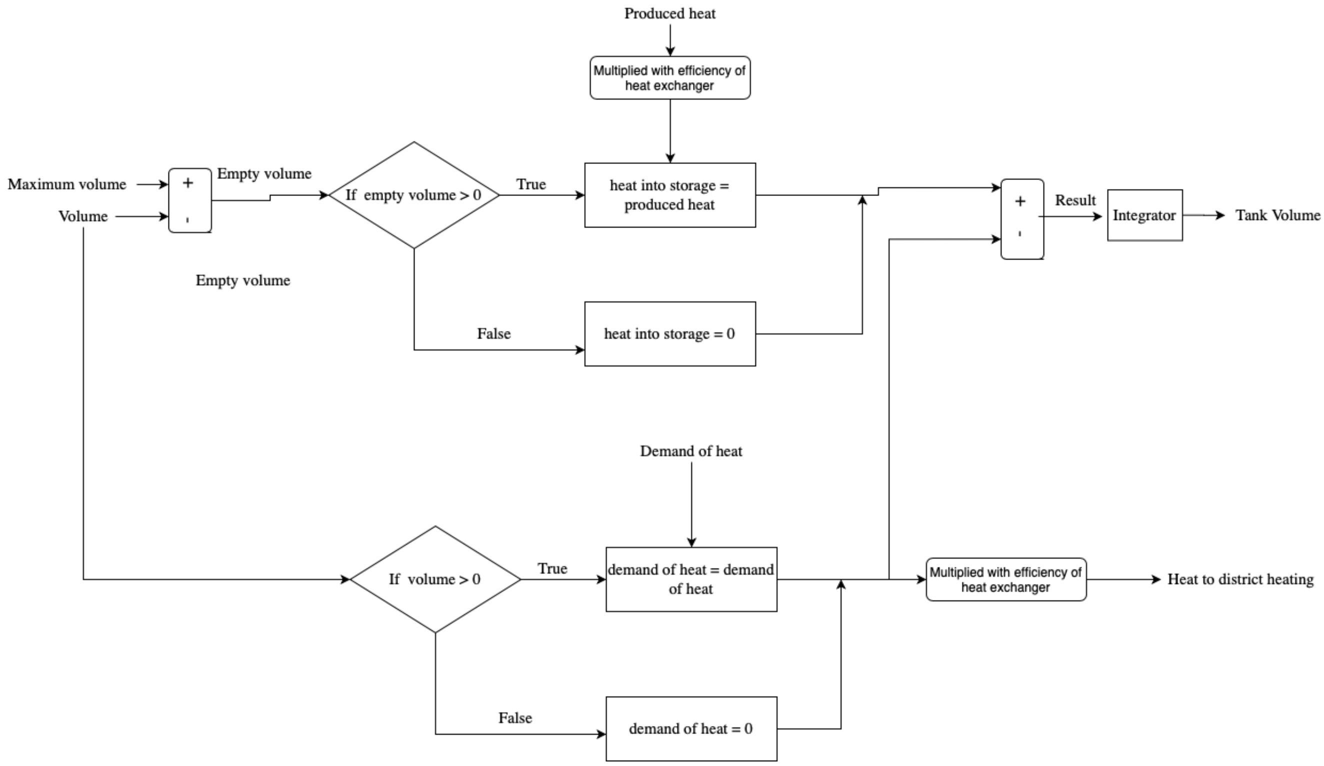

Figure 8: Flow chart of the heat storage. Two if-conditions controls when heat can be supplied to the storage respective taken out of the storage.

One if-condition controlled so that waste heat could not be stored in the heat storage if the storage was already full. Another if-condition controlled so that waste heat could not be taken out of the storage when the storage was empty. In Figure 8, the calculation of electricity consumption for the heat pump can not be seen. This electricity consumption was calculated based on the temperature drop during storage.

4.1.5 Methane storage

As with the heat storage, the methane storage was implemented as a subsystem. This part was developed in the previous bachelor thesis, however, during the simulations it was noted that it was possible to take out more methane than was in the storage. Parts of the subsystem needed to be adjusted so it was not possible to take out methane when the storage was empty. Figure 9 shows a flow chart of the methane storage. The first if-condition was kept as in the bachelor thesis whilst the second if-condition was corrected in this case study so that methane could only be supplied to the buses when enough methane was in the storage.

Produced methane and the demand of methane, both in m^3, were input to the subsystem while actual methane used and tank volume were output from the subsystem. Both produced methane from the power-to-methane system, the wastewater plant and the biogas plant were used as input to the storage.

At a site visit of the biogas plant, Uppsala Vatten informed that the biogas plant currently has a gas storage of 400 m^3 at 280 Bar. This was used in the dynamic model, leading to no extra investment costs for storage.

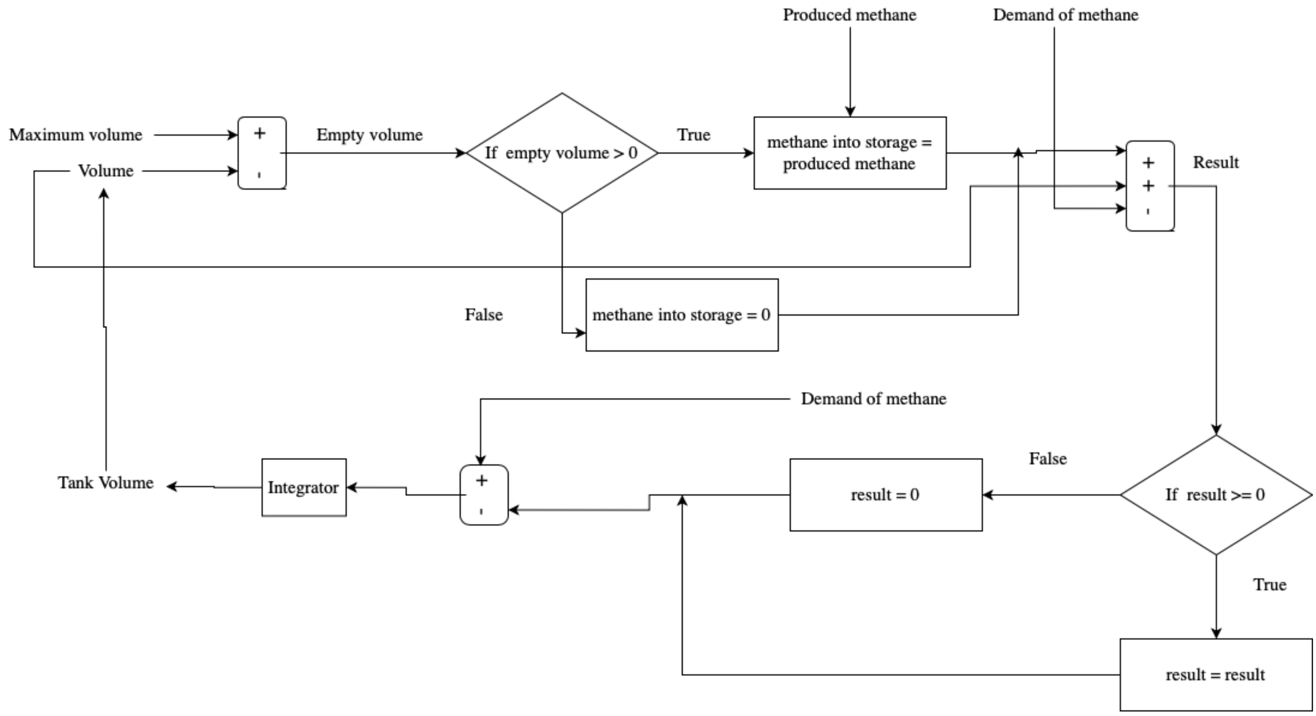

Figure 9: Flow chart of the methane storage. Two if-conditions controls when methane can be supplied to the storage respective taken out of the storage.

4.1.6 CO_2 control

In the previous bachelor thesis, an endless supply of CO_2 was used. In this case study, the supply of CO_2 was limited. Thereby creating the need to control the amount of CO_2 used so no more CO_2 was used than was available. A subsystem was created to control this, a flow chart of the subsystem can be seen in Figure 10. The subsystem calculated the amount of CO_2 that was used during the year based on the amount of hydrogen going into the methanation reactor. To do this, both produced hydrogen and CO_2 first needed to be converted to molar. Since the ratio between molar of hydrogen and CO_2 was 1:4, the molar of hydrogen needed to be four times the molar of CO_2. Based on this, the amount of CO_2 needed for a specific amount of hydrogen was calculated. The difference between this amount and the available CO_2 was calculated by the subsystem. A vector was given the value 0 if the amount of available CO_2 was enough. If the amount of available CO_2 was not enough, the vector was given the value 1. The subsystem then calculated how many hours of the year in which the available CO_2 was not enough.

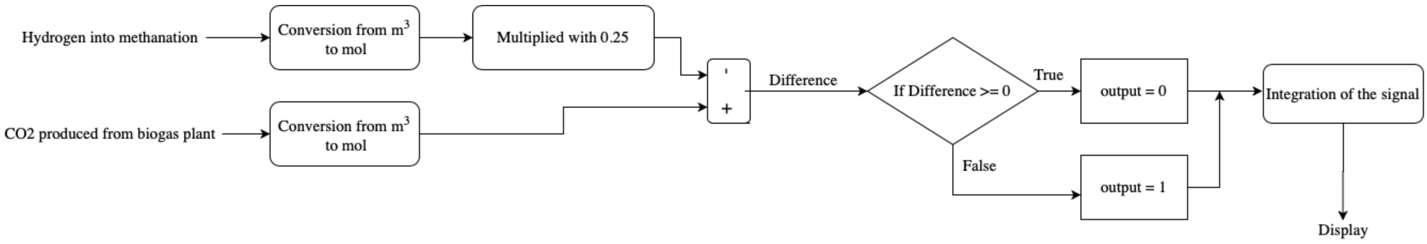

Figure 10: Flow chart of the CO2-control subsystem. The amount of needed CO_2 was calculated based on the amount of hydrogen used. The subsystem then calculated how many hours of the year in which the available CO_2 was not enough.

4.1.7 Solar power

In the previous bachelor thesis, solar power was not used and this part has therefore been developed completely within this case study. In the model developed in the previous bachelor thesis, the electrolyser was designed to operate at full load or no load. Therefore, the dynamic model had to be adjusted to handle part-load operation. This mainly consisted of two parts, adding electricity production from solar power and controlling the input to the electrolyser. This is illustrated in Figure 11. However, other smaller parts, for example the calculation of run hours, also needed to be adjusted to give a correct result for part-load operation.

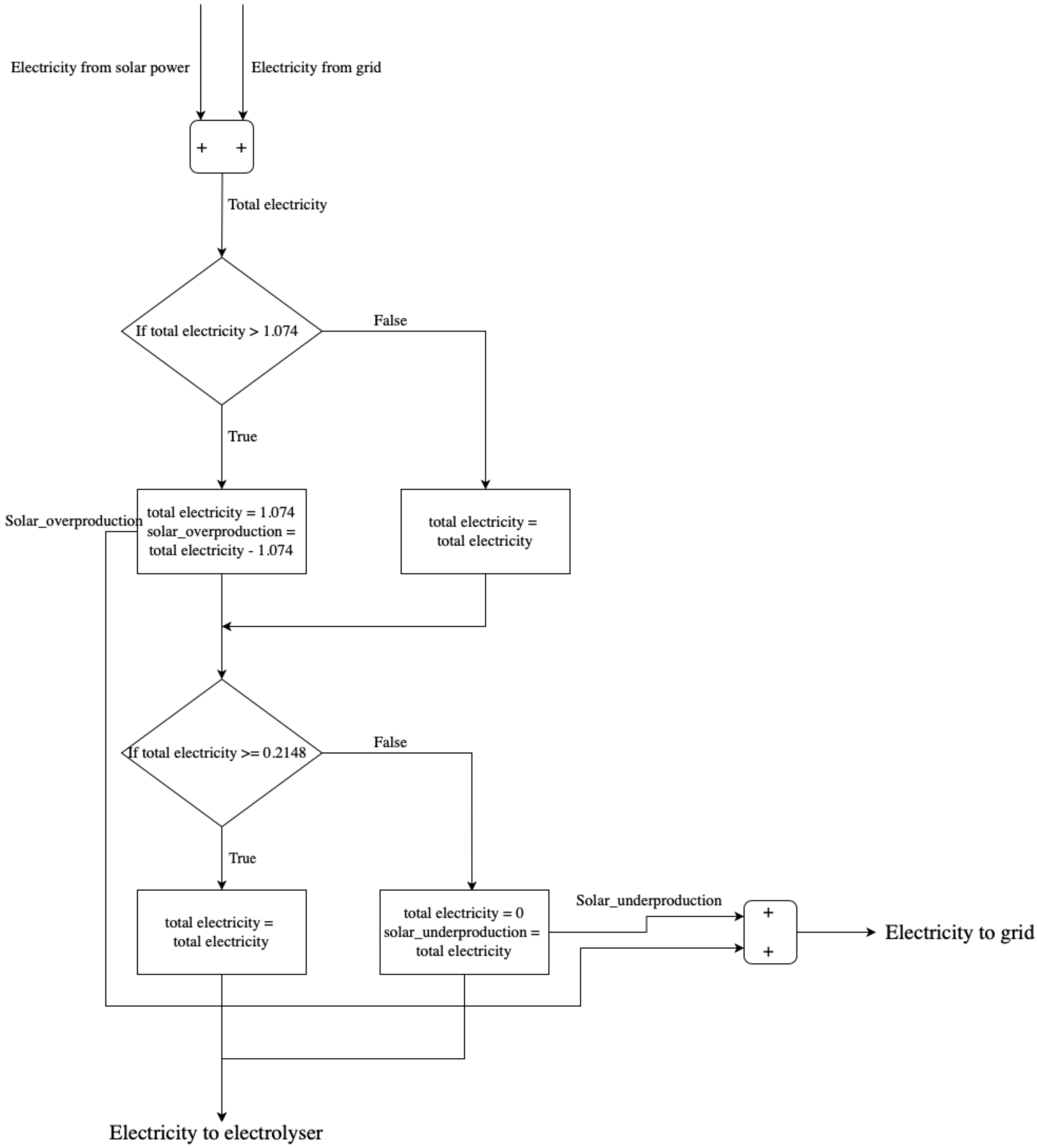

Figure 11: Flow chart of the changes due to adding solar power. Electricity produced from solar power was added to the electricity from the grid. Two if-conditions controlled so that the electricity going into the electrolyser was between 20 % to 100 % of nominal power.

When solar power was included the electrolyser had two sources of electricity, electricity from solar power and electricity from the spot market. Electricity from the spot market was still purchased based on the volume and electricity price as explained in section 4.1.1. The electricity from both sources was added before going into the electrolyser, the first step seen in Figure 11. At times when electricity was produced from solar power and purchased from the grid, the total electricity was higher than the nominal power of the electrolyser.

Since the electrolyser could only operate with loads between 20-100 % of nominal power, a subsystem was designed that controlled the electricity input to the electrolyser. This subsystem consisted of two if-conditions seen in Figure 11. If the electricity input was higher than 100 % of nominal power, the excess electricity was sold back to the spot market. If the electricity input from solar power and the grid was lower than 20 % of nominal power, the electricity was also sold back to the spot market instead of being used in the electrolyser. As seen in Figure 11, the subsystem divided the electricity into two parts, one part that was between 20-100 % of nominal power and went to the electrolyser and another part that was larger than 100 % or smaller than 20 % of nominal power and went back to the grid.

The economic model was also not designed to handle part-load operation and needed to be adjusted. These adjustments will be explained in section 4.2.

Table 2: Used values for calculations and their reference.

Typ of value	Value	Reference
Cold standby AEL	0.007 kWh/kW	Frank et al. [36]
Warm standby AEL	0.041 kWh/kW	Frank et al. [36]
Ramp load AEL	1.076 kWh/kW	Frank et al. [36]
Ramp time AEL	2 h	Frank et al. [36]
Cold standby BM	5 kWh/h	Frank et al. [36]
Warm standby BM	48 kWh/h	Frank et al. [36]
Ramp load BM	477 kWh/h	Frank et al. [36]
Ramp time BM	1 h	Frank et al. [36]
Hydrogen production	5.3 kWh/Nm^3	Buttler & Spliethoff[16]
Hydrogen production	59 kWh/kg	Buttler & Spliethoff[16]
Waste heat	125 kWh/MWh electricity	Buttler & Spliethoff[16]
Efficiency of heat exchanger	100%	Fakheri[37]
Grid fee	15 EUR/MWh	SWECO[13]
Density of CO_2	1.98 kg/Nm^3	Physics Handbook[38]
Density of H_2	0.0899 kg/Nm^3	Physics Handbook[38]
Density of CH_4	0.72 kg/Nm^3	Physics Handbook[38]
Density of water	997 kg/Nm^3	Physics Handbook[38]
Heat Storage Capacity of water	70 kWh/m^3	Bott et al. [22]
Specific heat capacity of water	0.00116 kWh/(kg*K)	engineeringtoolbox.com
COP heat pump	5	Viessman[39]
Molar mass of CO_2	0.00202 kg/mol	pubchem.ncbi.nlm.nih.gov[40]
Molar mass of H_2	0.0441 kg/Nm^3	pubchem.ncbi.nlm.nih.gov[41]

4.2 Economic model

The economic model was developed by McDonagh et al.[18] and adjusted to fit the dynamic model and the system in this case study. The previously developed economic model was developed as a MATLAB-program. To combine the dynamic model with the economic model, the economic model was changed to a MATLAB-function that could be implemented as a block into the dynamic model. The inputs to the function were calculated by the dynamic model. However, the calculations in the economic model were based on total production over the whole year. This means that the accumulated value of the whole years must be used and only the last value of the simulation was relevant.

The economic model calculated CAPEX, LCOE, NCF and NPV. The inputs to the economic-function are listed below:

utilised_hours - number of hour per year in which the system is operating

produced_solarpower - total produced electricity from solar power in MWh per year, if solar power was used

income_solarpower - revenues from selling excess solar power in € per year, if excess solar-power was sold

average_price - the average price for purchased electricity in €/MWh

standby_events_cold - total amount of times per year in which the system went into cold standby

standby_hours_cold - total number of hour per year in which the system was in cold standby

standby_hours_warm - total number of hour per year in which the system was in warm standby

waste_heat - total produced waste heat in kWh per year

total_payed - total payed for electricity in € per year

Oxygen_out_kg - total produced oxygen in kg per year

electricity_from_grid - total electricity purchased from the regular market in kWh per year

CH4_produced - total amount of methane produced in kg per year

Originally, the economic model calculated the economic parameters for a power-to-hydrogen system. To be able to use the economic model in this case study, the economic model needed to be adjusted to calculate the economic parameters for a power-to-methane system. This included adding economic data for biological methanation as well as adding revenues from sales of methane and removing revenues from sales of hydrogen. Also, the economic model was not considering the revenues from sales of oxygen, so those were also added.

The economic model was originally designed for a system that only operated at full-load or no load when adding solar power the economic model needed to be able to handle part-load operation. Therefore, the previously developed economic model needed to be adjusted. The previously developed economic model calculated produced hydrogen and waste heat within the MATLAB-program based on the run hours. With part-load operation, the production became an overestimation of the produced methane and waste heat. Therefore, the economic model was changed and the actual production from the dynamic model was used instead of the original calculations.

When solar power was used, the cost of producing electricity from solar power was added. The revenues from selling excess solar power were also added to the economic model.

Data regarding the cost of sold products and other costs that were used in the economic model can be found in Table 3.

Table 3: Used values for cost calculations and their reference

Costs	Value	Reference
CAPEX AEL	830 EUR/kW_{el}	McDonagh et al. [18]
CAPEX BM	1042 EUR/kW_{el}	Thema et al. [7]
OPEX AEL	0.04 % of CAPEX per annum	McDonagh et al. [18]
OPEX BM	0.04 % of CAPEX per annum	Assumed based on McDonagh et al. [18]
BoP AEL	0.2	McDonagh et al. [18]
BoP BM	1	Assumed based on McDonagh et al. [18]
Cost H20	1.3 EUR/m^3	McDonagh et al. [18]
Cost KOC	0.077	McDonagh et al. [18]
Cost Solar power	47.8 EUR/MWh	Fraunhofer ISE[28]
Cost standby electricity	100 EUR/MWh	McDonagh et al. [18]
Discount rate	0.065	McDonagh et al. [18]
CAPEX Heat Storage	293 EUR/m^3	IEA[23]
Grid fee	15 EUR/MWh	SWECO[13]
Price Heat	25 EUR/MWh	Vattenfall AB[20]
Price CH_4	1.23 EUR/kg	Uppsala Vatten[34], SWECO[13]
Price O_2	0.19 EUR/kg	SWECO[13]

4.3 Input Data

As stated in section 4.1, six files with data were imported into Simulink at the beginning of the simulation. They consisted of collected data necessary to run the simulation.

The data regarding electricity prices on the spot market over the year 2019 was taken from Nord pool[42].

The biogas production from the biogas plant and the wastewater plant was provided by Uppsala Vatten, who also supplied data regarding the biomethane demand of the buses[34]. This data was given for two or four measured times per day. Since the input files needed to be for every hour of the year for the simulation, the values were assumed to be constant between the measured times.

Heat_demand was a file created to have an output from the heat storage. The values in the file were assumed for year the 2019, with the assumption that the heat demand of the district heating was much larger than the amount of heat produced at the plant. So that the total amount of heat stored during the summer could be sold with a constant value per hour during the winter.

The produced solar power was given by the Photovoltaic Geographical information system, an online tool, from the European Commission, calculating the produced electricity for a specific solar power capacity in a specific location. Solar power with an installed capacity of 0.5 MW or 1 MW in Kungsängen, Uppsala, was used for this case study[43].

4.3.1 Fuel Demand of buses

As stated in the previous section, the demand of the buses was implemented as an input file based on the data provided by Uppsala Vatten. However, today the demand of the buses is already fulfilled by the biomethane produced at the biogas plant and the wastewater plant. Therefore, an increase in demand in the future was simulated. The new bus depot currently being built in Uppsala would make it possible to fuel the regional buses with biomethane and therefore it is likely that the demand will increase in the future.

The increase in demand was based on a number of simulations and expressed as a percentage of the current demand. The assumption was made, that the future demand would be the current demand of biomethane plus the current demand of natural gas. This was based on the goal of Region Uppsala to only use fossil-free fuel by 2020 [44] and biomethane being a substitute for natural gas. The aim was to fulfill as large part of the future demand as possible, while still not running the electrolyser full-time. Running the electrolyser full-time would prevent the system from being used to balance the grid, which is the main incentive behind power-to-gas.

4.4 Sensitivity Analysis

A sensitivity analysis was used to quantify the dynamic model's sensitivity to different parameters. Some values in table 3 were estimated based on other data or assumed when no source was available. Also, some sources stated that the values were uncertain. The sensitivity analysis aimed to determine to what extent these assumptions and estimations, as well as the uncertainty of data, might have affected the result of the simulations. For the sensitivity analysis the final dynamic model, with the use of by-products and solar power, was used. In the sensitivity analysis, the parameters below were increased and decreased by 25 %.

- CH_4 price
- Heat Price
- O_2 Price
- Grid Fee
- Electricity Price
- Cost of solar power
- Price for standby electricity
- BoP BM
- BoP AEL
- Replacement BM
- Replacement AEL
- OPEX BM
- OPEX AEL
- CAPEX BM
- CAPEX AEL

The values in Table 2 and 3 were used for comparison. The results were expressed as the percentage difference from the original value.

4.5 Mass and Energy Balance

To give an overview of the production and losses in the process a mass balance and an energy balance were created. The mass balance shows how the water was transformed into oxygen and hydrogen in the electrolyser and then combined with CO_2 to produce methane and water in the methanation.

The energy balance shows how the energy in the electricity is converted to hydrogen in the electrolyser and then converted to methane in the methanation. It also shows the losses that occur in both processes.

4.6 Simulations

The simulations consisted of three parts, the first part consisted in determining the design of the system with regards to boundary conditions and demand of buses. The second part consisted of different scenarios to investigate how the economic performance was effected by use of by-products and solar power. In particularly it was investigated if storing the waste heat in a heat storage during winter could increase the profitability. Lastly, a number of simulations were conducted to investigate how changes in investment costs for biological methanation and oxygen price effected the economic performance of the system. It was also investigated how changes in those parameters could be combined with other adjustments to make the system profitable.

4.6.1 Setting boundary conditions

To set the boundary conditions in the state-flow that controlled whether electricity was purchased from the grid or not, a number of simulations were conducted with different volume limits. The aim was to find the lowest volume where the demand of the buses was fulfilled for every hour of the year.

4.6.2 Setting fuel demand of buses

The fuel demand used in the simulations was set based on a number of simulations with different demands. The aim was to find a demand that fulfill as large part of the estimated future demand as possible, within the capacity of the electrolyser and the CO_2 produced by the biogas process.

4.6.3 Scenarios

The first five scenarios were investigating the use of the by-products waste heat and oxygen, particularly if heat storage was a possible way of increasing the profit. Since there was no available information regarding the price of waste heat during the winter, a number of simulations with different prices were conducted. Also, two simulations were conducted with the highest respectively the lowest CAPEX of heat storage to determine how CAPEX of the heat storage affected the result.

Scenario 6 and 7 were investigating if adding solar power could improve the profitability, with two different capacities of solar power. For scenarios 6 and 7 the dynamic model from scenario 4 was used, oxygen was sold as well as waste heat, with added solar power. The waste heat was sold during the whole year as the price for selling heat during winter was unclear. Also, another number of simulations investigated how the future development of cost for solar power affected the economic performance.

Scenario 1: Methane was produced according to demand, waste heat and oxygen were not sold.

Scenario 2: Methane was produced according to demand, oxygen was sold but not waste heat.
Scenario 3: Methane was produced according to demand, waste heat was sold when produced over the whole year. Oxygen was not sold.
Scenario 4: Methane was produced according to demand, waste heat was sold when produced over the whole year as well as oxygen.
Scenario 5: Methane was produced according to demand, both oxygen and waste heat were sold. The waste heat was stored during summer and sold during winter.
Scenario 6: Solar power with a capacity of 0.5 MW was used.
Scenario 7: Solar power with a capacity of 1 MW was used.

4.6.4 Potential for profitability

Lastly, a number of simulations were conducted to determine what was required in order to make the system profitable. During those simulations the effect that investment costs for biological methanation and oxygen price had on the economic parameters were investigated further. Those parameters were investigated since they were deemed most uncertain. The parameters were varied, compared to each other and combined with other adjustments, in order to determine what is required for the system to be profitable.

5 Results

In this section, the results from the simulations will be presented.

5.1 Mass balance

Figure 12 shows the mass balance of the process. Water and CO_2 are entering the process in the electrolyser respectively the methanation. In the electrolyser water is converted into 89 % oxygen and around 11 % hydrogen. The produced hydrogen is then combined with CO_2, with a mass 5.5 times the mass of hydrogen. Out of this reaction, 22 kg of methane is produced and 49 kg of water.

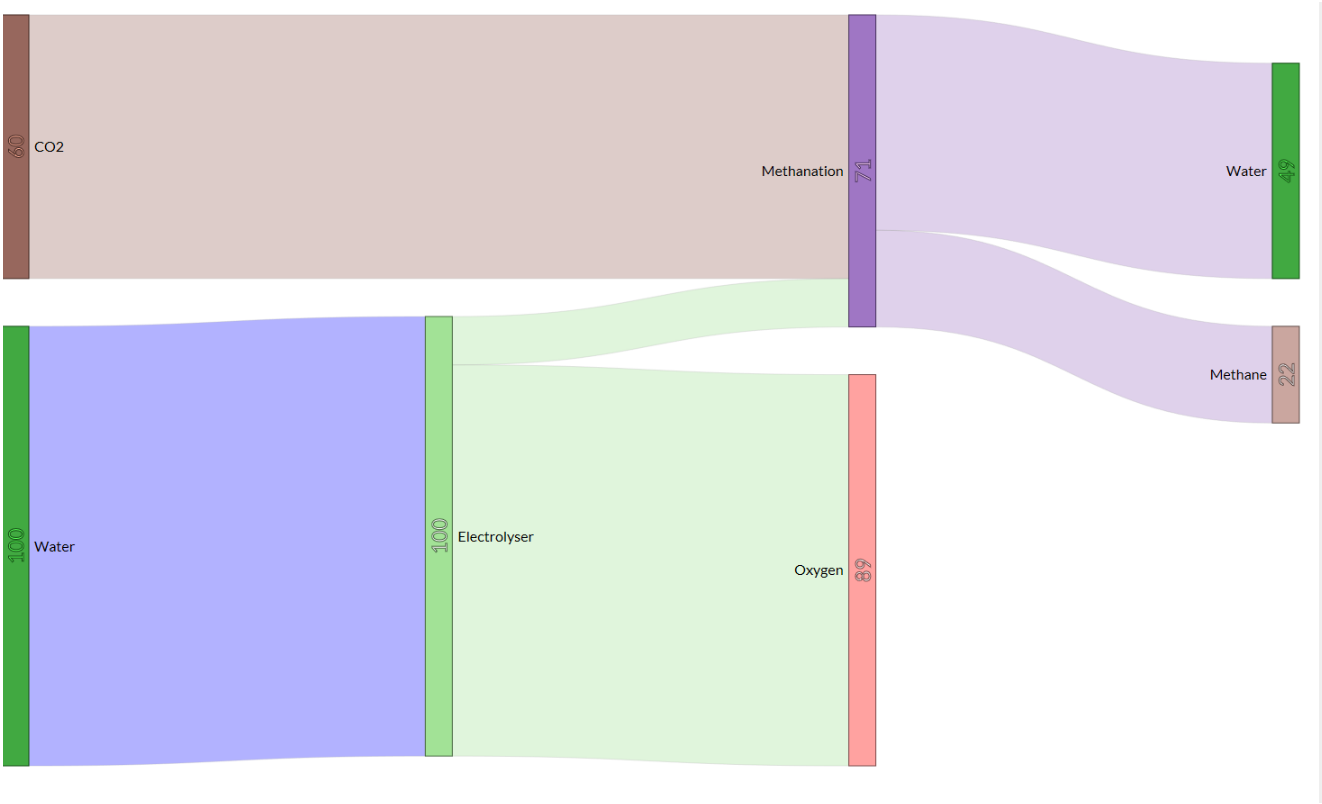

Figure 12: Mass balance of the process. CO_2 and water are converted to oxygen, water and methane through electrolysis and methanation.

5.2 Energy balance

Figure 13 shows the energy balance of the process. When electricity is converted into hydrogen in the electrolyser, 38 % of the energy is lost. Thereby, only 62 % of the energy supplied from the electricity is entering the methanation. In the methanation, another 13 % of the energy is lost. In total, 39 % of the energy is lost and another 12 % is lost as waste heat which can be recovered. 49 % of the electrical energy remains in the produced methane.

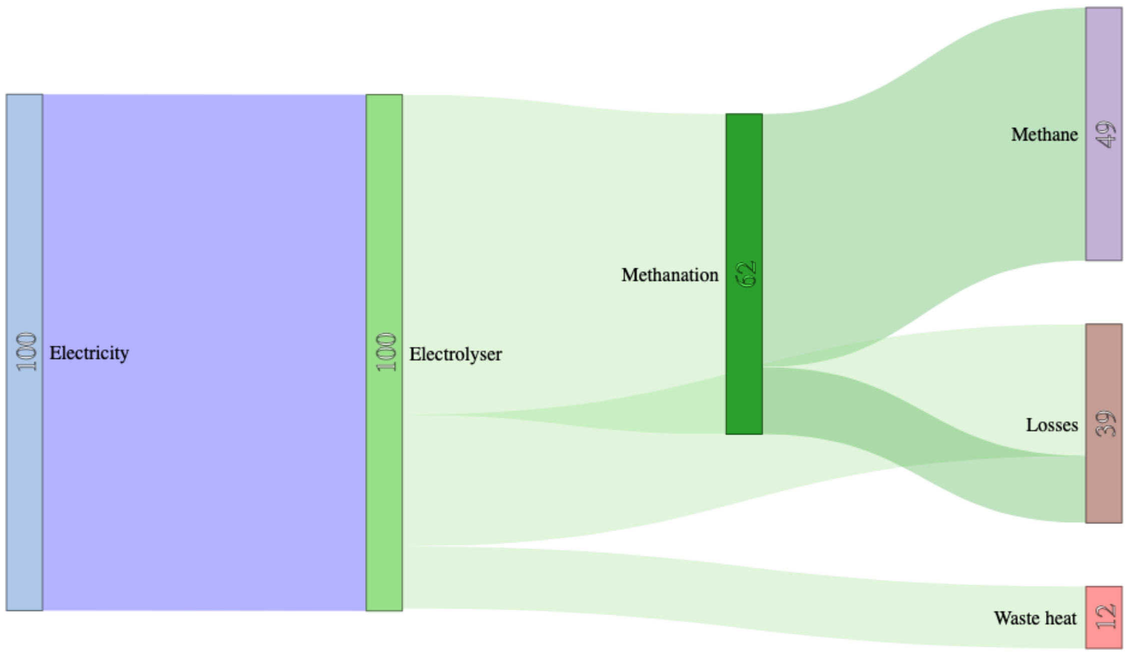

Figure 13: Energy balance of the process. Electricity is converted into methane and waste heat through electrolysis and methanation.

5.3 Sensitivity analysis of the base scenario

For the sensitivity analysis, a dynamic model without heat storage and with a 500 kW solar power capacity was used. As this was deemed the most likely scenario. The result of this simulation, referred to as base scenario, can be seen in Table 4.

Table 4: Economic parameters for the base scenario

Scenario	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
Base	4 740 000	2.98	-54 000	-4 630 000

The results from the sensitivity analysis were compared to the base scenario and expressed in percentage difference compared to the base scenario. The four following Figures show the results for LCOE, CAPEX, NCF and NPV separately. Figure 14 shows the result for the sensitivity analysis of LCOE.

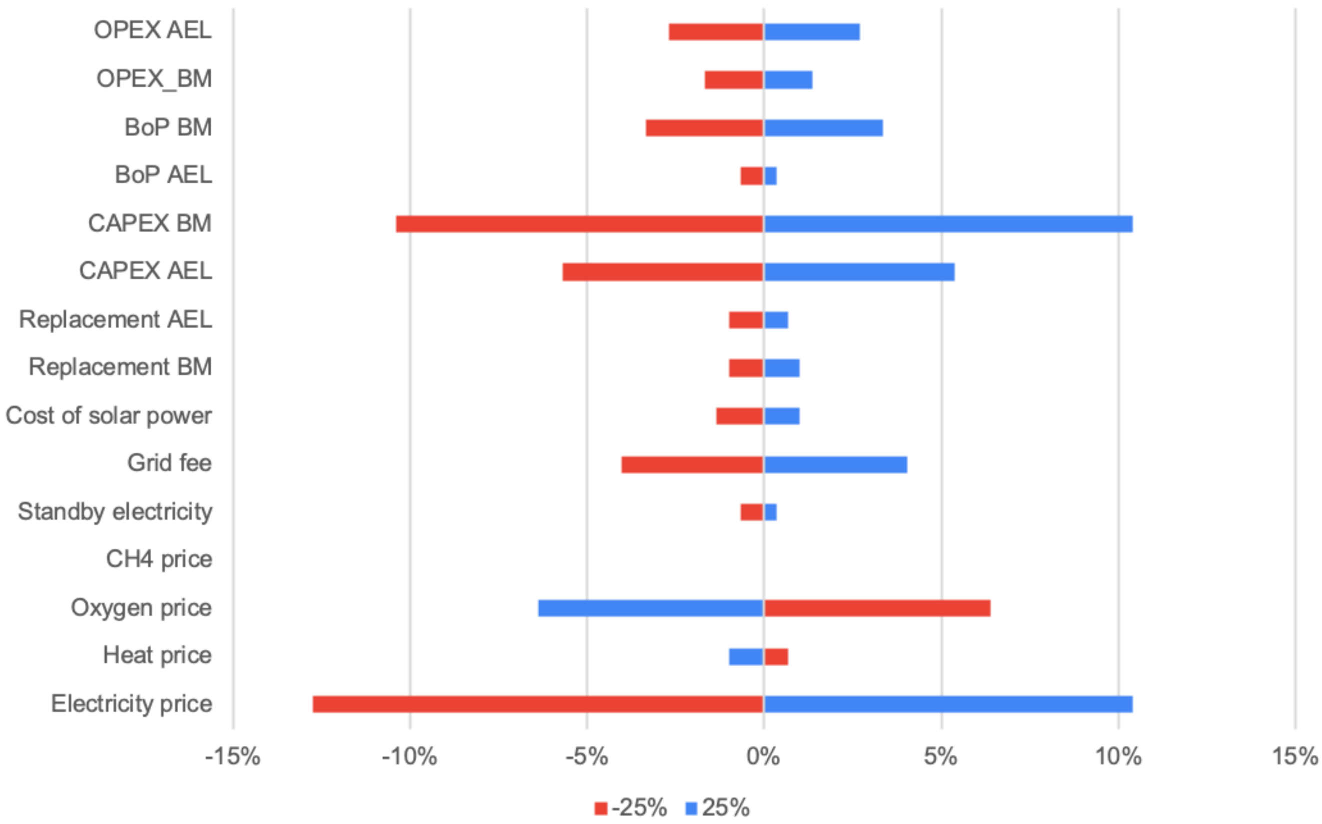

Figure 14: Result for the sensitivity analysis of LCOE. The values are expressed in percentage difference compared to the base scenario.

The electricity price is affecting LCOE the most, where a decrease by 25 % in the electricity price decreases LCOE by more than 13 %. Previous research has shown that the electricity price is the main operating cost for power-to-gas, thereby the results are in line with previous research. On the contrary, an increase in the electricity price with 25 % increased LCOE with 10 %. An increase in the price of oxygen also has a large impact on the result, where an increase in oxygen price of 25 % decreases LCOE by 6 %. However, a 25 % decrease in the price of oxygen increased LCOE by 6 %.

After the electricity price, the CAPEX of methanation and electrolyser has the largest effect on LCOE. CAPEX is used in multiple ways when calculating the LCOE, both directly and indirectly since OPEX and BoP are expressed as a percentage of CAPEX. Therefore a change in CAPEX will have a double effect on LCOE.

It can also be seen in Figure 14 that the price of CH_4 does not affect LCOE. Since LCOE is calculated as the total cost divided by produced methane, this is as it should be.

Figure 15 shows the result for the sensitivity analysis of the CAPEX.

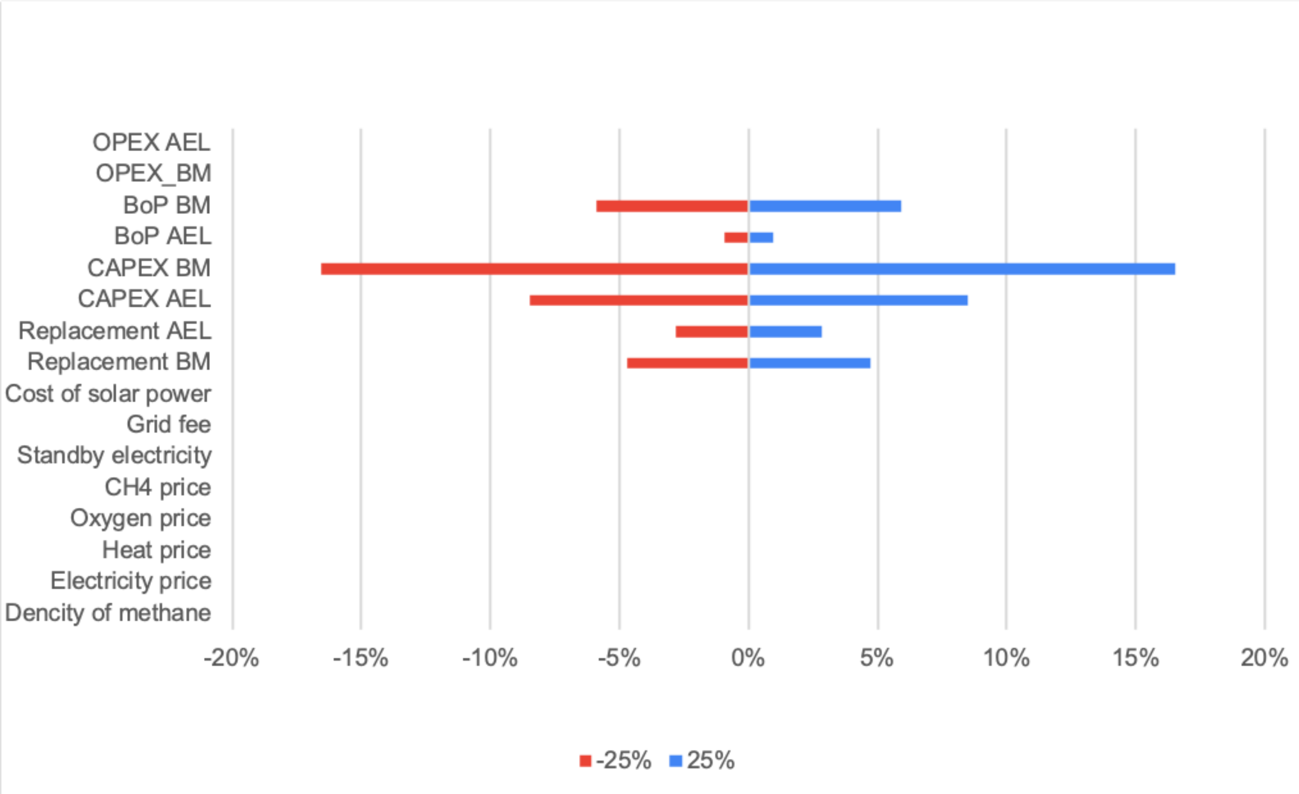

Figure 15: Result for the sensitivity analysis of CAPEX. The values are expressed in percentage difference compared to the base scenario.

The first aspect to note in Figure 15 is that most of the parameters do not affect the CAPEX of the system. CAPEX consists of the investment costs for electrolyser and methanation, balance of plant(BoP) and replacement costs which means that the other parameters should not affect the result. Figure 15 shows that this is also the case for the dynamic model developed. The investments cost(CAPEX) of biological methanation and electrolyser has a larger effect than BoP and replacement, which is logical since both BoP and replacement are calculated based on the CAPEX. CAPEX of methanation has a bigger effect on the total CAPEX than CAPEX of the electrolyser, which can be explained by the fact that the methanation is more expensive than the electrolyser. A 25 % decrease in CAPEX for biological methanation decreases the total CAPEX with more than 15 %, whilst an increase with 25 % increases the total CAPEX with more than 15 %.

Figure 16 shows the result for the sensitivity analysis of net cash flow.

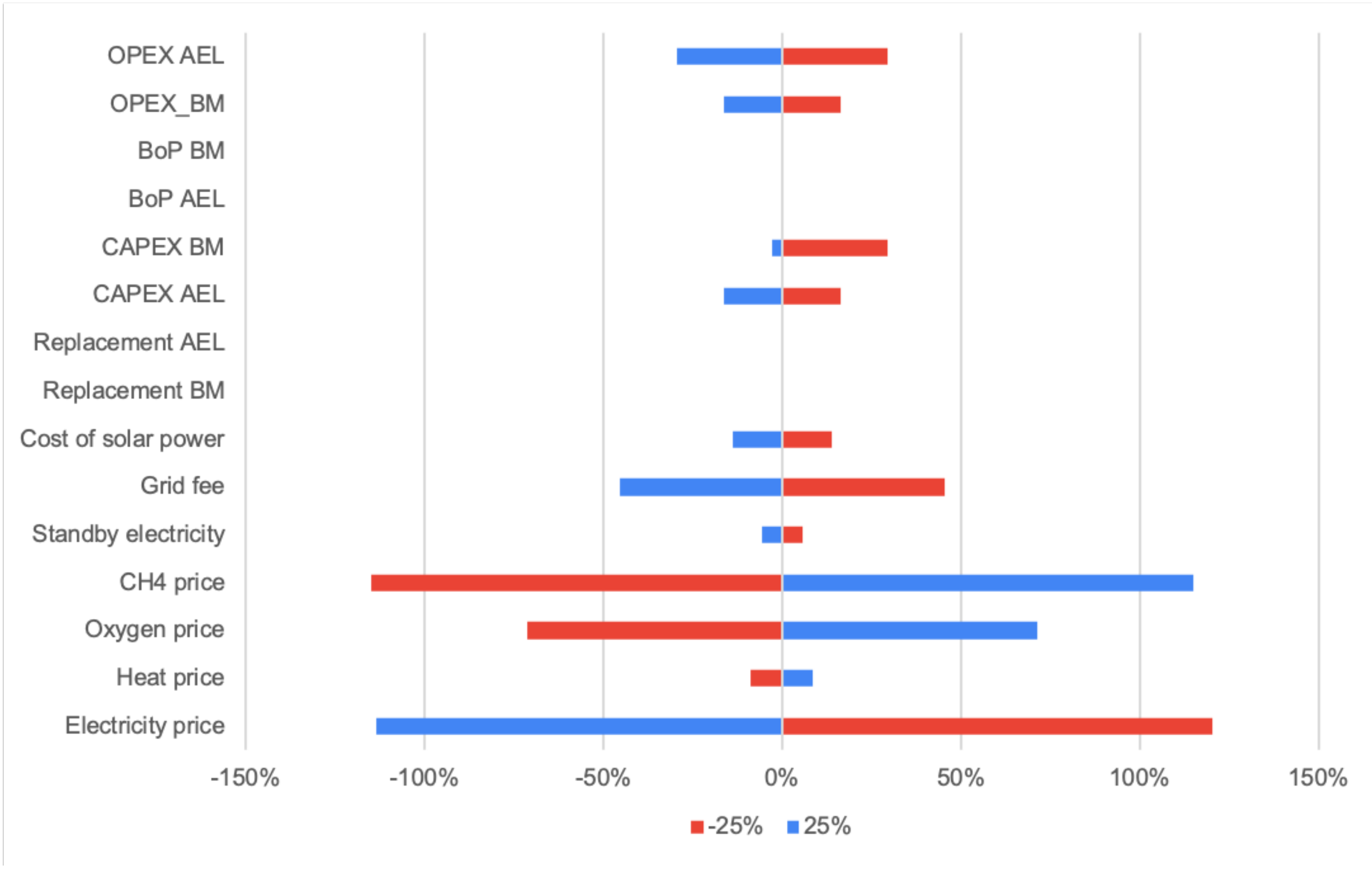

Figure 16: Result for the sensitivity analysis of net cash flow. The values are expressed in percentage difference compared to the base scenario.

In Figure 16, it can be seen that the net cash flow is very sensitive to changes in the CH_4 price, electricity price and partially also the oxygen price. Where a 25 % decrease in CH_4 price and increase in electricity price decreases the net cash flow with more than 100 %. For a 25 % increase in CH_4 price and decrease in electricity price the result is the opposite, a increase of net cash flow with more than 100 %. This sensitivity is inevitable since the system is producing a large amount of methane while consuming a large amount of electricity. Oxygen is as well produced at a large quantity and therefore the oxygen price also has a large impact on the net cash flow.

It can also be noted that both BoP and replacement do not affect the net cash flow, as it should be since the net cash flow calculates the difference between costs and revenues per year. CAPEX has a small impact on the net cash flow, due to the operational cost being calculated based on the CAPEX.

Figure 17 shows the result for the sensitivity analysis of NPV.

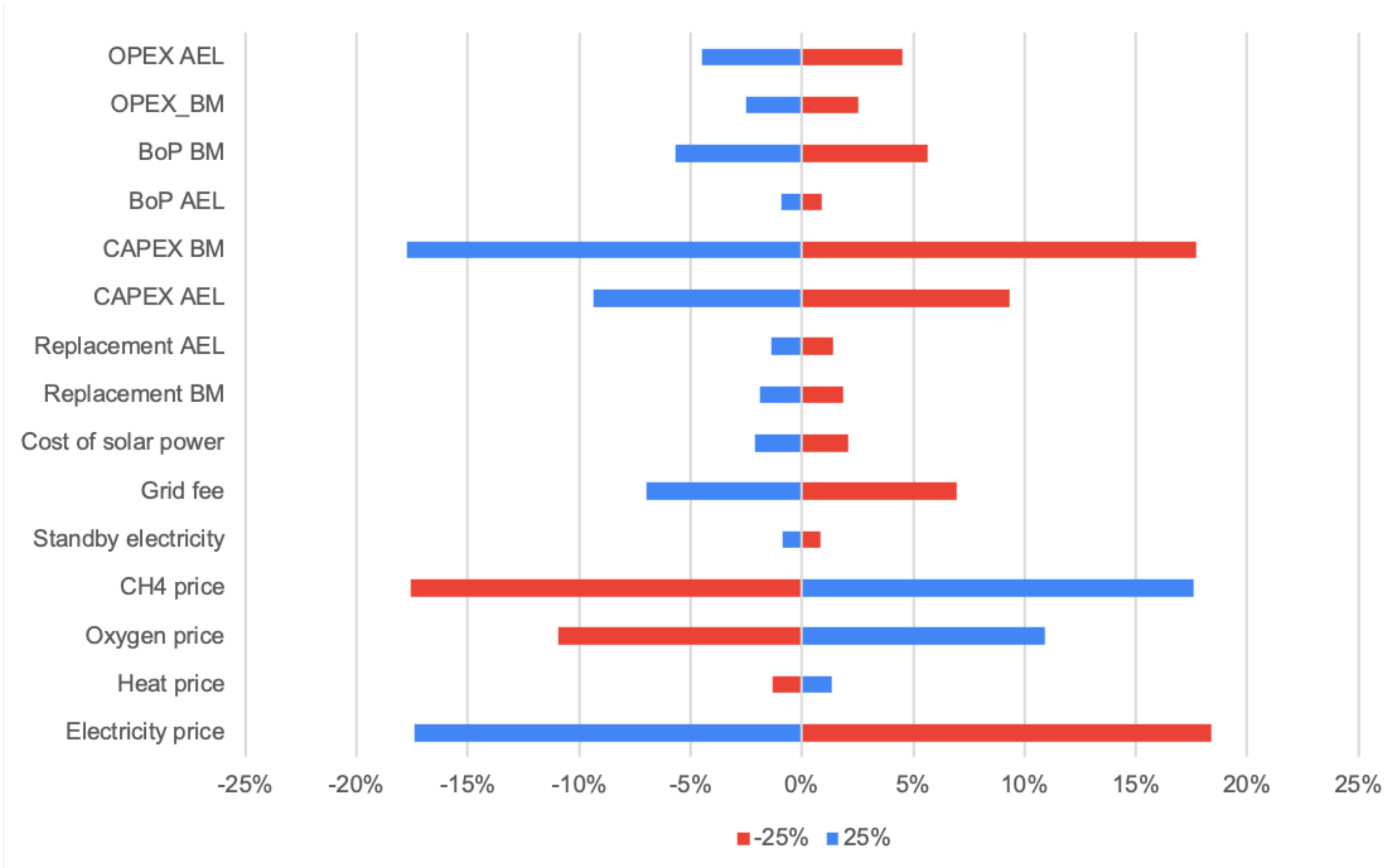

Figure 17: Result for the sensitivity analysis of NPV. The values are expressed in percentage difference compared to the base scenario.

The change is expressed as a percentage difference from the base value. All values of NPV is negative, which means that a negative change is decreasing the NPV even more. A positive change means that the NPV is increasing, however still negative.

Unlike the other economic parameters, NPV is affected by all parameters. The reason lies in the calculation of NPV. NPV is calculated as the discounted net cash flow minus CAPEX, thus including both operational and capital costs. In addition, the replacement is added to CAPEX of years 8,15 and 16, and therefore also affects the NPV. Electricity price, CH_4 price and CAPEX of BM have the largest impact on the NPV according to the result of the sensitivity analysis. Where a 25 % decrease of CAPEX for BM and electricity price decreases NPV with more than 15 %. A 25 % increase of the CH_4 increases NPV with more than 15 %. The oxygen price also has a large impact on NPV. The result of this sensitivity analysis is similar to the results of the sensitivity analysis for net cash flow and CAPEX.

It can be noted that all costs increase NPV as they are decreased by 25 % and decreases NPV when they are increased, as it should be. The price of waste heat, oxygen and CH_4 all increase NPV as they are increased and the other way around.

As can be seen in Figure 16 and 17, the dynamic model is sensitive to changes in CAPEX of the biological methanation, CH_4 price, oxygen price and electricity price.

5.4 Available CO_2

Simulations showed that the limit of CO_2 will not be reached even when the electrolyser is running full load over the whole year. This means that CO_2 is not a limiting factor with an electrolyser of this size.

Simulations also showed that only 40 % additional CH_4 can be produced from an electrolyser with a capacity of 1.074 MW. For higher demands, the production from the system will not fulfill the demand of methane at certain hours of the year.

5.5 Setting boundary conditions

As mentioned in section 4.1.1, electricity was purchased from the spot market depending on the volume of the methane storage and the electricity price. In 2019, the average price of electricity on the spot market was 38.36 EUR/MWh. 0.12 and 109.45 EUR/MWh were the lowest respectively the highest price of electricity during the year. As the aim was to purchase electricity below the average price, the limit for electricity was set to 35 EUR/MWh.

The limit for the volume was set based on a number of simulations, the result can be seen in table 5.

Table 5: Simulations: Different volume limits of the methane storage

Volume limit (m^3)	Produced methane (kg)	Difference between demand and supply (Yes/No)
50	154 000	Yes
100	176 000	Yes
150	194 000	No
200	204 000	No
250	214 000	No
300	224 000	No
350	243 000	No

A limit of at least 150 m^3 was needed to fulfill the demand of the buses at every hour of the year. However, a limit of 200 m^3 was chosen for the remaining of the simulations. This was to have a slightly higher margin for fulfilling the demand.

5.6 Scenarios

This section shows the results of the scenarios. Table 6 and table 7 show the results for scenario 1-7 and the base scenario for comparison. Afterward, the economic performance of scenario 5, with heat storage, was investigated further because of the uncertainties in the price of waste heat. Lastly, the future development of solar power was also investigated further.

Table 6 shows the results for scenario 1-5, where the use of the by-products waste heat and oxygen were investigated. Comparing scenario 2, selling oxygen, with scenario 1(not selling oxygen) it can be seen that the revenues from selling oxygen have a high impact on the net cash flow. Although the net cash flow is still negative it increased with around 154 000 EUR/a when oxygen is sold.

Table 6: Simulations: Economic performance for scenario 1-5, use of by-products

Scenario	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
Base	4 740 000	2.98	-54 000	-463 0000
1	4 740 000	3.95	-250 000	-7 200 000
2	4 740 000	3.19	-96 000	-5 180 000
3	4 740 000	3.86	-230 000	-6 950 000
4	4 740 000	3.09	-78 000	-4 930 000
5	7 080 000	3.63	-100 000	-6 360 000

The revenues from selling waste heat do not have a large effect on the net cash flow. Without selling waste heat the net cash flow was -250 000 EUR/a, when waste heat was sold the net cash flow increased with only 20 000 EUR/a. Selling both oxygen and waste heat increased the net cash flow with 172 000 EUR/a.

The values for scenario 5 in table 6 is with the same price of waste heat as in scenario 3 and 4. This leads to a decrease in revenues due to losses in the heat storage and electricity consumption of the heat pump. In addition, CAPEX increased due to the investment costs for heat storage. The results in section 5.6.1 give a better understanding of the potential of profitability from heat storage.

For the next simulations scenario 4 was used for comparison. Selling oxygen and waste heat generates additional revenues and there is no reason not to sell oxygen and waste heat. Scenario 5 was not used because of the uncertainties in the selling price of heat as discussed in section 2.5.2.

Table 7 shows the results for scenario 6 and 7, as well as scenario 4 for comparison.

Table 7: Simulation: Economic performance for scenario 6-7, adding solar power.

Scenario	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
4	4 740 000	3.09	-78 000	-4 930 000
6	4 740 000	2.98	-54 000	-4 630 000
7	4 740 000	2.98	-56 000	-4 660 000

The net cash flow is higher with solar power, as well as the NPV. An interesting result is that solar power with a capacity of 0.5 MW yields higher net cash flow and NPV than a capacity of 1 MW. For a capacity of 1 MW, the run hours where 6985 hours/a and the average price for electricity purchased from the grid was 44.8 EUR/MWh. For a capacity of 0.5 MW, the run hour were 7108 hours/a and the average price of electricity purchased from the grid was 46.4 EUR/MWh. In other words, despite a higher average electricity price for a capacity of 0.5 MW, the net cash flow and NPV were higher. In both scenarios the price limit was 35 EUR/MWh, as set in section 5.5, but due to the volume in the storage being too low electricity was at times purchased at a higher price than the limit.

The explanation for the difference in economic performance can be understood by comparing the average price for electricity on the spot market over the year and the cost of producing electricity from solar power. With the average electricity price on the spot market over the year being 38.36 EUR/MWh and a production cost for solar power of 47.5 EUR/MWh, there is a high possibility that electricity will be sold for a lower price than the cost of production. Studying the electricity price and the production of solar power it can be seen that the high production of solar power often occurs at times when the electricity price is low, thus electricity will be sold at a lower price than the cost of production. A larger capacity will increase the amount of electricity sold to a lower price than the cost of production.

Looking at the revenues from selling excess electricity. The 0.5 MW capacity had revenues of 16 000 EUR/ from selling electricity whilst the 1 MW capacity had revenues of 26 000 EUR/a from selling electricity. This accounts for an increase of 64 % whilst the cost of producing electricity increased with 100 %. Because of this, a capacity of 0.5 MW was more profitable. However, both a small and large solar power capacity were more profitable than buying all electricity from the grid.

5.6.1 Heat storage

As discussed in section 2.5.2, the price for waste heat during winter is uncertain. Therefore, a number of simulations with different prices of waste heat were conducted. Table 8 shows the results of those simulations.

Table 8: Simulations:Price for waste heat

Price for waste heat (EUR/MWh)	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
30	7 080 000	3.62	-99 000	-6 310 000
40	7 080 000	3.48	-91 000	-6 210 000
50	7 080 000	3.54	-84 000	-6 120 000
60	7 080 000	3.51	-76 000	-6 020 000

It can be seen that even a price of 60 EUR/MWh yields lower net cash flow and NPV than scenario 4. Even though increasing the price increases the revenues, the increase in revenue is not enough for the system to become more profitable than scenario 4. A price of more than 60 EUR/MWh is deemed unlikely since the selling price of heat to the end customers during winter is 77.33 EUR/MWh in Uppsala[25].

As stated in section 2.5.1 the investment cost for heat storage, of the type TTES, varies between 110 - 475 EUR/m^3. Two simulations were conducted with the lowest and highest value of the investment cost to investigate the effect that the investment cost has on the economic performance. A heat price of 30 EUR/MWh was used for these simulations.

Table 9: Simulations:Minimum and maximal value of the investment costs for heat storage

CAPEX (EUR)	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
110	5 620 000	3.36	-99 000	-5 620 000
475	8 540 000	3.87	-99 000	-6 990 000

It can be seen that a change in CAPEX does not affect the revenues, whilst the LCOE is decreased slightly. LCOE is higher than scenario 4, even with the lowest CAPEX.

A final simulation was conducted with the lowest investment cost(110 EUR/m^3) and the highest price of waste heat(60 EUR/MWh). The result, in table 10 shows that even these conditions did not yield a higher NPV than scenario 4, although the net cash flow is slightly higher than scenario 4. However, a price of 60 EUR/MWh and investment cost as low as 110 EUR/m^3 is unlikely.

Table 10: Simulations: Minimum CAPEX with maximal price

CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
5 620 000	3.25	-76 000	-5 330 000

5.6.2 Development of solar power

The cost of solar power is expected to decrease in the future, as stated in section 2.6.1, due to the development of the technology. As the cost of solar power currently is higher than the average price of electricity on the spot market over 2019, this limits the profitability of adding solar power. Future development, with a decrease in the cost of solar power, may increase the profitability of adding solar power. Therefore, a number of simulations with the expected future costs of solar power were conducted. Table 11 shows the results with a decrease in costs as seen in Figure 2.

Table 11: Simulation: Future development of the cost of solar power.

Cost of solar power (EUR/MWh)	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
47.8	4 740 000	2.98	-54 000	-4 630 000
40.1	4 740 000	2.95	-50 000	-4 570 000
35.4	4 740 000	2.94	-47 000	-4 530 000
33.2	4 740 000	2.93	-45 000	-4 510 000

With the current cost of solar power, the net cash flow is around -54 000 EUR/a. Until 2030 the cost of solar power is expected to decrease down to 33.2 EUR/MWh, with this price the net cash flow is decreased down to -45 000 EUR/a. However, LCOE and net present value are only slightly decreased. Future development will improve the economic performance, but will not alone make the system profitable.

5.7 Potential for increased profitability

This section shows the simulations that were conducted to determine what is required to make the system profitable. As stated in section 4.6.3, these simulations are based on the insecurities in the investment costs for biological methanation and the price of oxygen. Lastly, changes in biological methanation and the price of oxygen were combined with other adjustments to investigate how a profitable system could be achieved.

5.7.1 Investment costs for biological methanation

In the sensitivity analysis of the base scenario, it can be seen that CAPEX for biological methanation has a large impact on LCOE and NPV. As discussed in section 2.7, the value of CAPEX as well as BoP and replacement of biological methanation are uncertain. Therefore, a number of simulations with reduced CAPEX were conducted to investigate how a reduction in CAPEX is effecting net cash flow and NPV. The result can be seen in Figure 18.

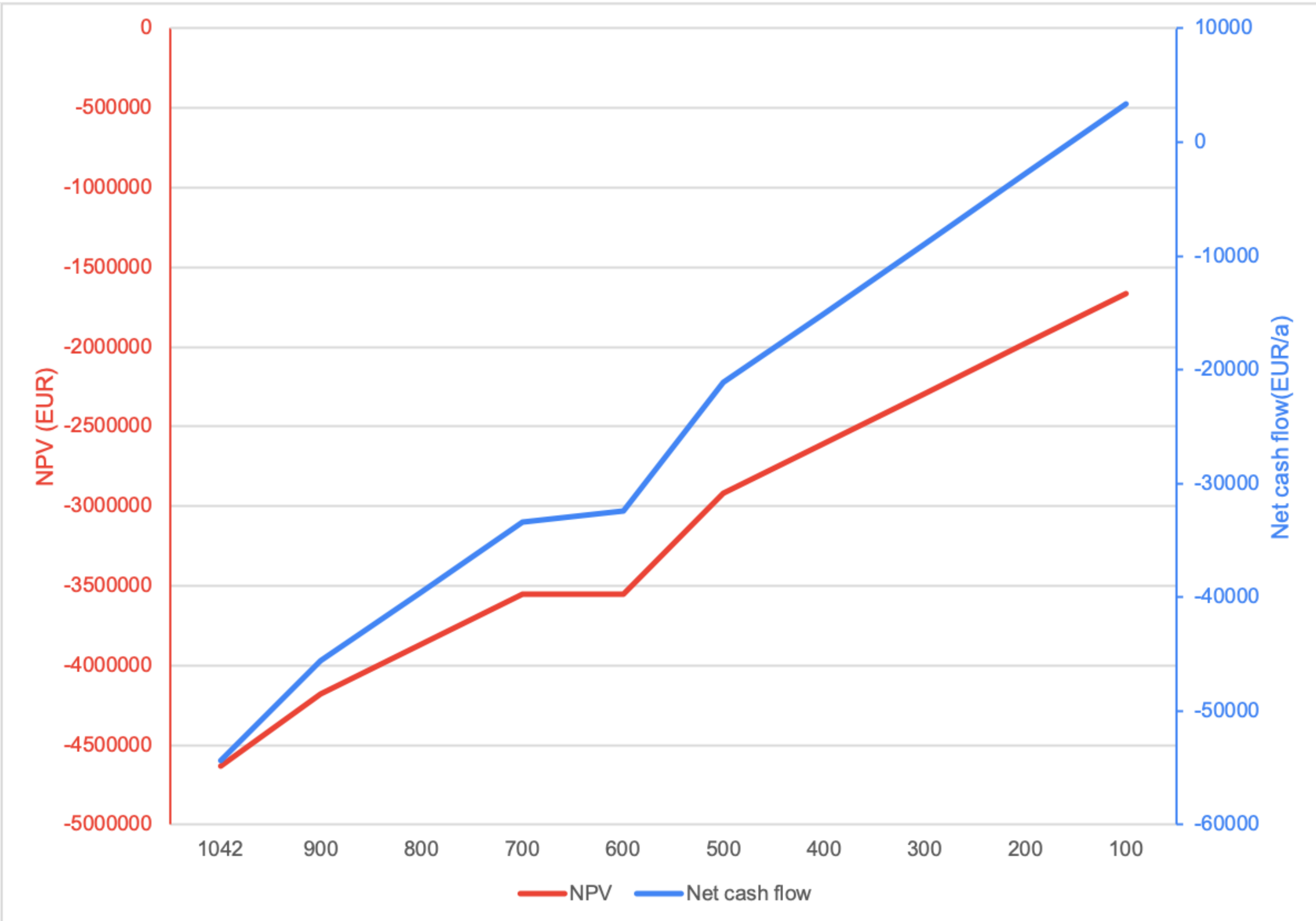

Figure 18: Net cash flow and NPV as a function of CAPEX(in kW_{el})for BM, not including balance of plant or replacement

In Figure 18, it can be seen that even a CAPEX as low as 100 EUR/kW_{el} yielded a negative NPV, however a positive net cash flow. This value of CAPEX yielded a net cash flow of 3 400 EUR/a which although positive is very low. However, with a balance of plant of 1 the total investment costs for the biological methanation including BoP would be 200 EUR/kW_{el}. This value is still lower than the lowest value presented in the literature, mentioned in section 2.7. Since the value for BoP is also uncertain, another number of simulations were conducted where the CAPEX of biological methanation, BoP and replacement were reduced with a certain percentage down to a reduction of 90 %. Figure 19 shows the results of these simulations.

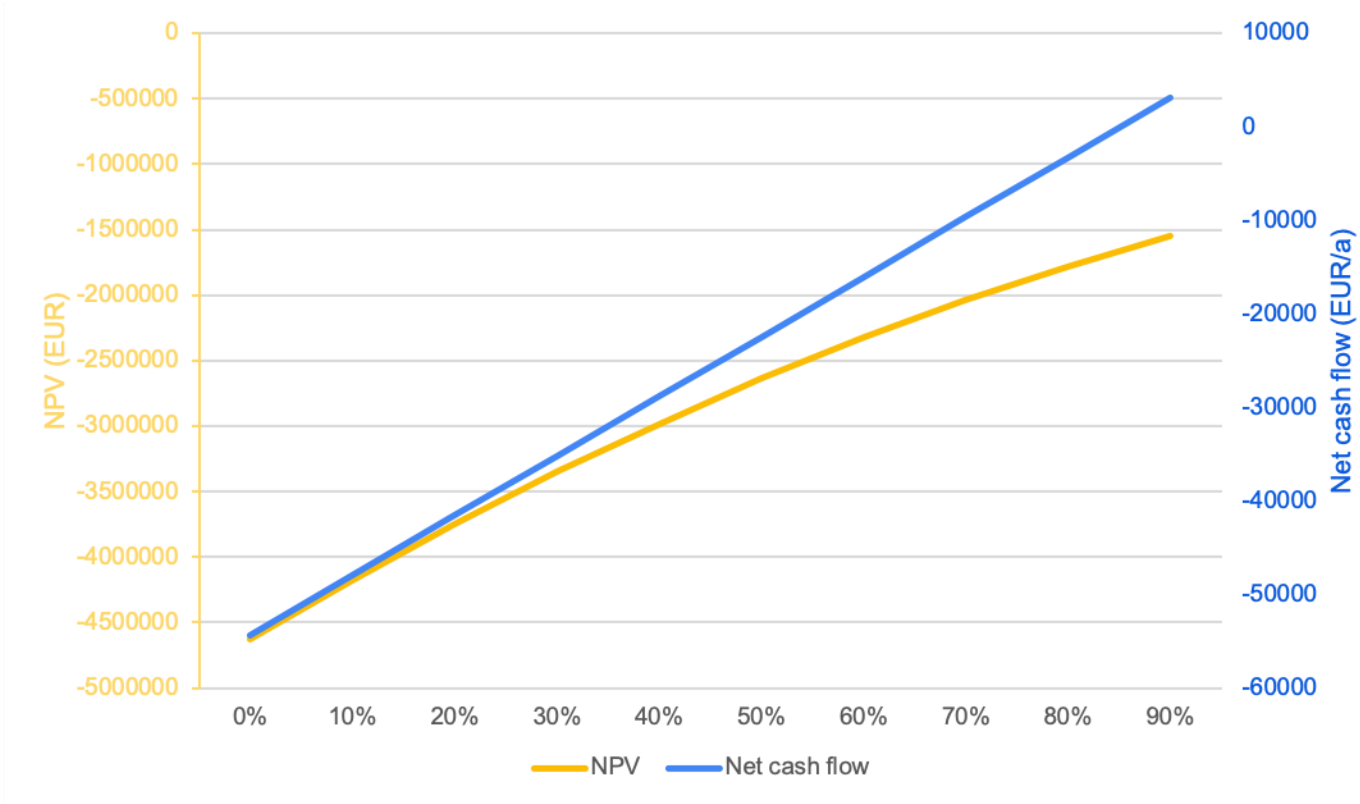

Figure 19: Net cash flow and NPV as a function of the percentage reduction in CAPEX for BM price.

Even a reduction of CAPEX, BoP and replacement of 90 % did not yield a positive NPV. This shows that a reduction of the investment cost for methanation can not alone reduce the total investment costs enough to yield an economically profitable system. Decreasing costs need to be combined with increased revenues to make the system profitable.

5.7.2 Increasing revenues

The result from the previous section indicates that to achieve profitability a reduction of costs needs to be combined with an increase in revenues. Costs and revenues of the system were discussed in section 2.8.1. The sensitivity analysis of the base scenario showed that the cost for electricity and price for methane have a large impact on net cash flow and NPV. However, they are determined by the market with limited ability to affect them. The price of oxygen also has a large impact on the economic performance and the value used is uncertain since it is an estimate based on the selling price of oxygen. The price of waste heat may also change depending on the development of the district heating market. However, the previous result has proven that the price of waste heat does not have a significant impact on the economic performance. Therefore, it was chosen to only investigate the price of oxygen further.

A number of simulations were conducted, where the change in net cash flow and NPV depending on the price of oxygen was investigated. Figure 20 shows the net cash flow and the NPV as a function of the oxygen price up to 0.7 EUR/kg.

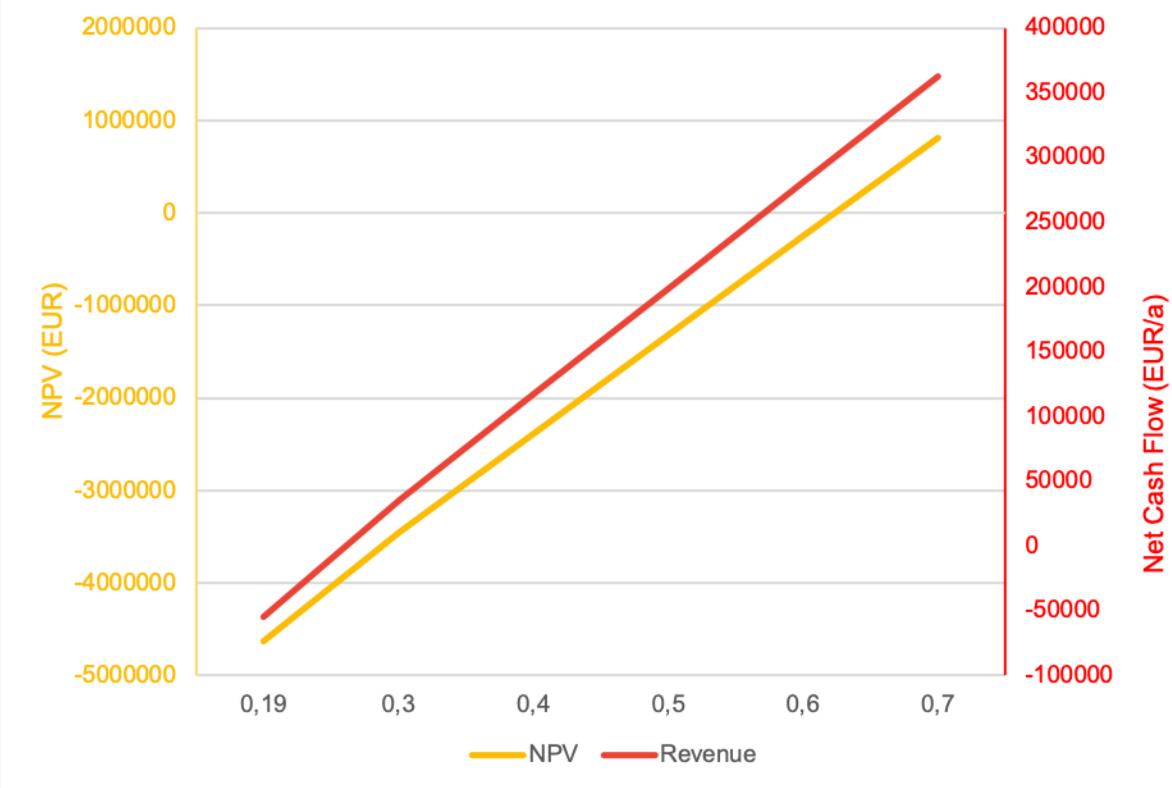

Figure 20: Net cash flow and NPV as a function of oxygen price up to 0.7 EUR/kg.

Figure 20 shows that an oxygen price of 0.3 EUR/kg yields a positive net cash flow. At a price of 0.7 EUR/kg, a positive NPV is also yielded. However, it might be unlikely to achieve an oxygen price of 0.7 EUR/kg since the selling price of oxygen by AGA is around 0.65 EUR/kg[45]. Although this price is excluding VAT, value-added tax, it is for oxygen in bottles. Adding oxygen in bottles means extra costs, thus reducing the revenues from selling oxygen. It could be possible to get a price higher than 0.19 EUR/kg, that was used in the previous simulations, if the cost of putting oxygen in bottles is low. At least an oxygen price of 0.4 EUR/kg might be likely.

5.7.3 Combined effects

The result in the previous section shows that an increase in the price of oxygen can not alone create a profitable system nor can a decrease in CAPEX of biological methanation alone create a profitable system. An increase in the price of oxygen needs to be combined with a decrease in the costs. Based on this, another number of simulations were conducted where a reduction in CAPEX, BoP and replacement of biological methanation was combined with an increased price of oxygen.

Table 12 shows the effect that a changed oxygen price has on the economic parameters, when a 60 % reduction in CAPEX, BoP and replacement of biological methanation were assumed.

Table 12: Simulations: Economic performance of a system with 60 % reduction in CAPEX, BoP and replacement in combination with different prices of oxygen

Oxygen price (EUR/kg)	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
0.19	2 370 000	2.11	-1 600	-2 320 000
0.3	2 370 000	1.66	74 000	-1 150 000
0.4	2 370 000	1.26	160 000	-85 000
0.5	2 370 000	0.86	240 000	980 000
0.6	2 370 000	0.46	320 000	2 050 000

In Table 12, it can be seen that an oxygen price of 0.3 EUR/kg yields positive net cash flow and an oxygen price of 0.5 EUR/kg also yields a positive NPV. With an oxygen price of 0.4 EUR/kg, the LCOE has decreased down to 1.26 EUR/kg. This value is close to the selling price of methane and other adjustments could make the system profitable. In Table 13 different adjustments that will yield a profitable system at an oxygen price of 0.4 EUR/kg and a reduction of investment costs for methanation with 60 % can be seen. These adjustments were chosen because they were deemed likely.

Table 13: Simulations: A oxygen price of 0.4 EUR/kg and a 60 % reduction of CAPEX for BM, in combination with other adjustments.

Adjustment	CAPEX (EUR)	LCOE (EUR/kg CH_4)	Net cash flow (EUR/a)	NPV (EUR)
Tax relief on biogas	2 370 000	1.26	212 000	656 000
Increase in run hours	2 370 000	0.85	284 000	1 590 000
40 % reduction in CAPEX AEL	1 730 000	1.00	170 000	606 000
All three combined	1 730 000	0.68	387 000	3 440 000

When combining a reduction of CAPEX for both electrolyser and methanation, an oxygen price of 0.4 EUR/kg, tax relief on biogas and increased run hours an LCOE of 0.68 EUR/kg CH_4 was achieved. This accounts for 45 % of the selling price for biomethane and high profitability would be possible with an NPV of 3 440 000 EUR. Increasing the run hours, without reduction of CAPEX for electrolyser and tax relief, would yield an LCOE of 0.85 EUR/kg CH_4, which is around 70 % of the selling price of biomethane(without tax relief). Only tax relief of biomethane would give an NPV of around 656 000 EUR. A 40 % reduction in CAPEX for the electrolyser would give an NPV of 606 000 EUR, which is rather low compared to the other two adjustments.

A 60 % reduction of CAPEX, BoP and replacement for biological methanation would mean a total investment cost for methanation of around 584 EUR/kW_{el}, including balance of the plant. This value is higher than the investment cost predicted by DENA, which is 200-400 EUR/kW_{el} [29]. A 40 % reduction of the CAPEX for electrolyser would mean a CAPEX of 498 EUR/kW_{el}, not including balance of the plant. This value is higher than the estimate for 2040 by Thema et al., which estimates a CAPEX of around 491 EUR/kW_{el}[7]. Based on these values, a 60 % reduction of CAPEX for methanation and a 40 % reduction of the CAPEX for electrolyser is likely in the future.

6 Discussion

The results indicate that by designing a control system where electricity is purchased if the volume of the methane storage is less than 200 m^3 or the electricity price is lower then 35 EUR/MWh, the system can provide methane according to the demand of a bus fleet. With a 1.074 MW electrolyser the used CO_2 is well below the available CO_2. Thus, the availability of CO_2 is not limiting in this case study. However, with a 1.074 MW electrolyser only a 40 % addition of biomethane can be produced. If the whole demand of natural gas is to be substituted with biomethane a larger electrolyser is needed.

However, the results indicate that it may be difficult to achieve profitability of the system. The use of by-products plays an important role in achieving a profitable system. Especially the revenues from selling oxygen were shown to have a large impact on the economic performance. An oxygen price of 0.7 EUR/kg could alone make the system profitable. However, such a high price may be unlikely based on the selling price of oxygen. Selling waste heat only had a small impact on economic performance. An average price for waste heat of more than the used value of 30 EUR/MWh is unlikely, especially for low-temperature waste heat. This result goes in line with previous results from both SWECO and Energiforsk, which both concluded that selling the by-products, especially oxygen, is important to achieve profitability.

The results also indicate that heat storage is not profitable since both the net cash flow and NPV were reduced compared to selling the waste heat during the year. LCOE was increased in comparison with scenario 4, selling both oxygen and waste heat over the year, but lower than scenario 1, where waste heat was not used at all. To increase the profitability with heat storage, the price during winter must be high enough to compensate for the investment costs of the heat storage and the losses during storage. For this case study, this was not the case even with a price of 60 EUR/MWh. A higher price is unlikely based on the current selling price of waste heat.

Adding solar power increased the revenues, but the result showed that a capacity of 0.5 MW increased the net cash flow more than a capacity of 1 MW. With the current cost of solar power, electricity is at times sold to a lower price than the cost of production. However, the economic performance of both scenarios with solar power was still better than without solar power. Future development of solar power may increase the profitability further but the results indicate that the economic performance is only slightly improved when the cost of solar power is decreased. Using the produced electricity smart could also improve the economic performance further. For example by controlling the operation of the electrolyser so that electricity is sold when the price is high and used in the electrolyser when the price is low. This was not investigated in this case study.

Comparing the results of this case study to previous studies, the result differs in some parts one of which is the average price of purchased electricity. In the pre-study by SWECO, they assumed an average electricity price of 30 EUR/MWh[13]. In this case study, the average price was calculated by the dynamic model based on the cost of purchased electricity and run hours per year. The average price for purchased electricity varied between 45-60 EUR/MWh for different scenarios, with the highest value being almost twice as high as the average price use by SWECO. Since the electricity price has a large effect on the net cash flow and NPV, the difference in electricity price yields a large difference in the results. In the case study from Energiforsk, the results showed that the electricity price needed to be below approximately 30 EUR/MWh to achieve profitability[14]. With the average electricity price calculated by the dynamic model being higher than the average electricity price used in previous studies it is reasonable that the result differs.

The result of scenario 1 yielded an LCOE of 3.95 EUR/kg and an NPV of -7 200 000 EUR, far from a profitable system. A reduction of CAPEX, BoP and replacement of BM and an oxygen price of 0.6 EUR/kg gave an LCOE of 0.46 EUR/kg and an NPV of 2 047 000 EUR, an increase in NPV of 9 250 000 EUR. 0.46 EUR/kg was the lowest LCOE achieved in this case study. However, achieving an oxygen price of 0.6 EUR/kg may not be highly likely since the selling price of oxygen is 0.65 EUR/kg. Nonetheless, this result indicates that there is a large potential for improving the economic performance of the system. Another scenario(Table 13) yielded an NPV of 3 440 000 EUR despite the LCOE being slightly higher. This value was the highest NPV achieved in this case study. This scenario required a reduction in costs for biological methanation, a reduction in CAPEX for the electrolyser as well as an increase in run hours and tax relief on biogas. The uncertainty in investment costs for biological methanation has been discussed in section 2.7 but all sources agree that the investment costs are expected to decrease in the future. Therefore an investment cost for biological methanation of 584 EUR/kW including balance of the plant, which is what a 60 % reductions equal, is deemed likely in the future. Increasing the run hours can be done easily, although increasing the run hours make it impossible to use the system to stabilize the grid since it will operate the whole year. Tax relief on biomethane is a political question and difficult to determine if it is likely in the future. If the will to promote green technologies increases in the future it might be likely that the tax on biomethane would decrease. It is also possible that the price of biomethane will increase if the demand for biomethane increases. Therefore, it is likely that all the conditions for this scenario will be possible in the future. Even if not all of the conditions are possible, all of the condition states in Table 13 will together with a reduction of CAPEX and increase of oxygen price yield a profitable system.

6.1 Verification and validation of the dynamic model

Only a limited amount of power-to-methane plants exist and data regarding the operation of those plants are not publicly available. In addition, all existing systems consist of either pilot or demonstration plants and the investment costs of those plants do not represent a full-scale project. Therefore, it was not possible to validate the developed dynamic model.

The sensitivity analysis of the base scenario shows that the dynamic model developed behaves as intended. The parameters that should not affect specific economic parameters do not affect them, and the parameters that should affect specific economic parameters affect them. The economic parameters are shown to be rather sensitive to electricity price, CH_4 price, oxygen price and CAPEX. Previous research has shown that the economic parameters are rather sensitive to changes in electricity price as well as oxygen price, so these results from this case study go in line with previous research. The sensitivity of certain parameters is inevitable due to the nature of the system, where a large amount of electricity is consumed and a large amount of methane and oxygen are produced. A small change in the price of electricity, methane and oxygen therefore have a large impact on economic performance. In addition, the investment costs for these types of systems are high thus also having a large impact on the economic performance of the system. Awareness of the sensitivity of the dynamic model and reliable data are necessary when using the developed dynamic model.

A weakness with the dynamic model is that parameters are sometimes during the simulation converted between units as well as converted between different pressures. These conversions add extra uncertainty with regard to the value used for the conversion. Since the electrolyser and methanation are operating at a lower pressure than the methane storage, conversion between pressures is inevitable. However, conversion between units is avoidable and should be avoided. Because the data provided was measured in different units, it was not possible to avoid the conversion between units for this case study. Measuring the data in the same unit would decrease the uncertainty of the results. Other uncertainties of the dynamic model can also be derived from the used data. Besides being measured in different units, the produced methane and fuel demand of the buses were measured only two or four times a day. To be able to run the dynamic model, the data had to be extrapolated to every hour of the year. This also adds extra uncertainty to the results of the simulations. Measuring the data for every hour of the year would decrease the uncertainty of the results. However, comparing the demand of biomethane according to the data provided by Uppsala Vatten with the use of biomethane according to the environment and vehicle database FRIDA from The Swedish Public Transport Association[10], only a very small difference is noted. With the difference being very small, the extra work of measuring every hour of the year might not be motivated since it will only yield a very slight improvement of the results.

The uncertainty of the result of the simulation is mostly connected to the uncertainties in the used data. The uncertainty of CAPEX for biological methanation and the price of oxygen are probably the uncertainty that affects the results the most. The price of waste heat is also uncertain, however since the revenues from selling waste heat only account for a small part of the total revenues this uncertainty is unlikely to have a large effect on the results. To achieve a reliable result correct data is vital which the sensitivity analysis of the base scenario also shows.

The advantage of the dynamic model developed is that it can easily be adjusted to changes in the system or other types of systems. Almost all data that are specific for the system is imported as MATLAB-files and can easily be changed to other files to investigate other systems. In addition, the dynamic model produces and stores a lot of data about the system so that other aspects than the economic performance can be investigated. The process is visualized in graphs within the Simulink-model which makes it easy to get an overview of the process. Data is also exported into MATLAB were it can be used for further investigations.

Another advantage is that all parameters such as methane production are calculated for every hour of the year, making the analysis of the system detailed. The production is adjusted after the demand of fuel for every hour of the year, creating a dynamic system. For the economic analysis, it is an advantage that the electricity price at exactly the time when the electricity is purchased is used instead of using an average electricity price.

6.2 Further research

There are more options that may increase the profitability that can be investigated. The oxygen produced could be used in the nearby wastewater plant to air the wastewater. Today, air is used for this purpose and this requires a lot of energy. Since air only contains 20 % oxygen and therefore a larger amount needs to be pumped. Using pure oxygen would require less energy which may reduce the costs. As the use of by-products has a large impact on the economic performance it would be interesting to investigate this option.

Another option that could be investigated is liquefied biomethane. Large quantities are required for liquefied biomethane to be profitable, integrating power-to-methane into the current biogas plant may increase the production enough to achieve a large enough volume for liquefying the biomethane. The benefit of liquefying the biomethane is that other heavy vehicles than buses might be interested in using this fuel, thus increasing the selling price.

Since the biological methanation has higher investment costs than catalytic methanation it would be interesting to investigate if using catalytic methanation instead could increase the profitability. Changing to catalytic methanation would require storage of hydrogen, which has high costs, so it is not obvious if this would increase the profitability. Also, the possibility of in-situ biological methanation could be investigated. Since in-situ biological methanation has lower investment costs than ex-situ, which was used in this case study.

As the result indicates that the investment costs of biological methanation have a large effect on the economic performance it might be more profitable to sell hydrogen instead of methane. However, the demand of hydrogen is lower than the demand of methane so it might be difficult to find a market for the produced hydrogen. To find a market for the hydrogen it could be investigated if it would be possible to mix hydrogen into the biomethane produced at the biogas plant. This is possible up to a certain percentage and could reduce the costs and increase the revenues.

Lastly, since the main incentive behind power-to-gas is to stabilize the electric grid it would be interesting to explore the possibility of getting compensation from the grid owner for stabilizing the grid.

7 Conclusion

A dynamic model, with an acceptably good performance according to the objectives of this case study, was developed. The dynamic model is sensitive to the parameters electricity price, CH_4 price, oxygen price and investment costs for electrolyser and methanation. To achieve a correct result reliable data regarding those parameters are needed.

A power-to-methane system can be integrated into the current biogas plant in Uppsala, to increase the production of biomethane. A control system can be designed so that biomethane is produced according to the demand of fuel. Selling waste heat and oxygen are important to improve the economic profitability of the system but heat storage does not improve the profitability. Adding solar power improves economic performance but a capacity of 1 MW shows lower net cash flow and NPV than a solar power capacity of 0.5 MW.

If a total investment cost for biological methanation of around 600 EUR/kW and an oxygen price of 0.4 EUR/kg are possible, there are multiple adjustments that would achieve a profitable system. Either by increasing the run hours, decreasing investment costs for the electrolyser or tax relief on biogas. All of those adjustments are deemed likely in the future. Other options may also be possible, like decreased electricity prices or increased price of biomethane.

Lastly, there are many other possibilities to explore for further research such as the possibility of using oxygen at the nearby wastewater plant. Liquefied biogas could also be investigated, as it might yield a higher selling price. Since the investment costs for biological methanation had a large effect on the economic performance it would also be interesting to investigate the possibility of changing to catalytic methanation. The possibility of decreasing the investment costs by using in-situ methanation could also be investigated. All of the mentioned options could improve the economic performance further.

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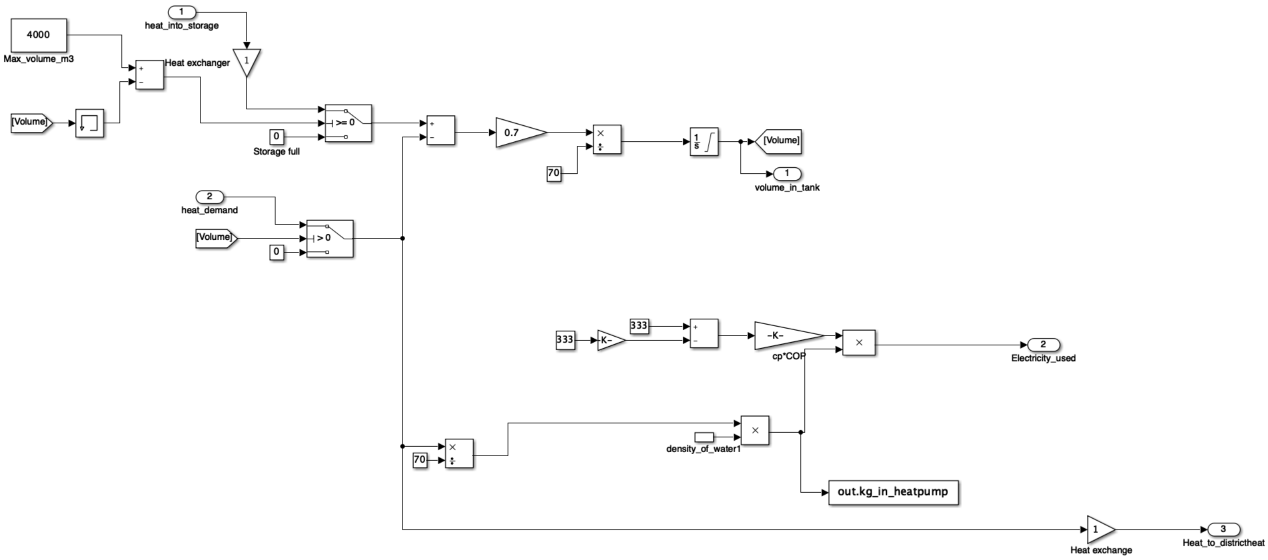
A Electrolyser-function

```
function [Hydrogen_out_m3, Hydrogen_out_kg, kWh_per_Nm3, waste_heat, Water_deionized_in_kg

kWh_per_Nm3 = 5.3
kWh_per_kg = 59
waste_heat_per_MW = 125

%not_hydrogen =(0.091* (MWh_per_year*1000)/(kWh_per_Nm3))

Hydrogen_out_m3 = ((MWh_per_year*1000)/(kWh_per_Nm3))

Hydrogen_out_kg = ((MWh_per_year*1000)/(kWh_per_kg))

waste_heat = (MWh_per_year*waste_heat_per_MW)

Water_deionized_in_kg = (Hydrogen_out_kg/0.111907)

Oxygen_out_kg = (Water_deionized_in_kg*0.888093)]
```

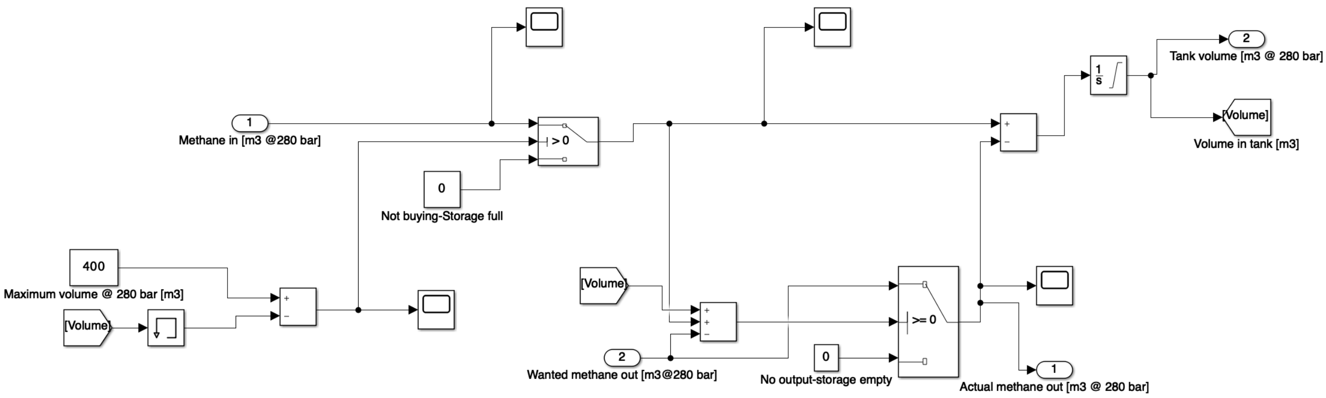
B Methanation

```
function [Methane_out_m3_STP, Methane_out_kg, water_out]  = fcn( h2_in)

 h2_in_kg= (h2_in*0.0898)                 % multiplied by density

 CO2_in_kg = (h2_in_kg*5.458294471)        %multiplied by the density

 Methane_out_kg = (h2_in_kg+CO2_in_kg)*0.308078021

 Methane_out_m3_STP = (Methane_out_kg/0.7168)

 water_out = (h2_in_kg+CO2_in_kg)*(1-0.308078021)
```

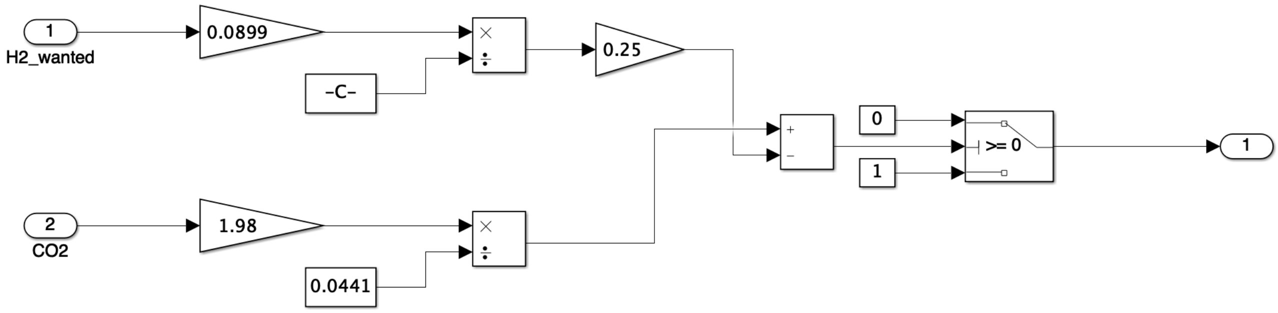
C Heat Storage



D Methane Storage



E CO2 controll



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