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Life Cycle Cost Analysis of Biogas Upgrading via a Bio Trickling Filter

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Abstract

This paper was written in the Spring semester of 2019 as part of a master's thesis course, concluding the master's program of Energy Technology at the University of Southern Denmark.

The paper details the results of a Life Cycle Costing, estimating the costs of a biotrickling filter used for biogas upgrading. It also includes a Life Cycle Assessment, using the ReCiPe 2016 impact assessment methodology, to gauge the impact of the technology. In order to supply a comparative angle, the same methodologies were applied to both a water scrubbing and chemical absorption upgrading technology.

The biotrickling filter is based on the experiment described by Trisha L. Dupnock and Marc A. Deshusses, in their 2017 paper *High-performance biogas upgrading using a biotrickling filter and hydrogenotrophic methanogens*. The experiment uses hydrogenotrophic methanogens to convert CO_2 and H_2 into CH_4, thereby not only upgrading the biogas, but also increasing the methane yield.

The paper takes the perspective of a private Danish investor, investing in a joint biogas plant with a substrate intake of manure, straw and energy crops. The biogas is then upgraded to natural gas quality and injected into the natural gas grid. This paper includes the full investment and compares the Net Present Values of three different alternative upgrading technologies: the biotrickling filter, a high-pressure water scrubber, and an amine based chemical absorber.

The paper concludes that the biotrickling filter upgrading technology is a financially viable investment in many scenarios but cannot be said to be competitive with market leaders such as water scrubbing and chemical absorption. The primary reason for this is the high cost of electricity needed to supply the hydrogen.

The paper also concludes that the Life Cycle Impact of the BTF compares favorably to the competitors – in great part due to the CO_2 being enriched, rather than stripped and released into the atmosphere. When aggregating the results into a single score, however, the technologies are practically identical, due a) the consequential nature of the LCA and b) the high impact of fossil resource scarcity. As the production of 1 MJ of biogas results in the avoidance of 1 MJ of natural gas depletion, this becomes the overwhelming contribution to the single score, across alternatives.

The technology does have several opportunities for gaining a competitive advantage – if hydrogen is produced at low electricity cost and stored for later use or if electrolysis technologies mature more quickly than expected, the BTF gains an edge which could allow it to compete with the market leaders.

The paper concludes that the technology holds promise, and under the assumptions made in the paper, the technology can be considered financially viable, and environmentally competitive. It also concludes, however, that the LCC and LCA ought to be reiterated, once a plant scale experiment has been conducted, so that a higher data maturity may expel the uncertainty surrounding the current results.

Readers Guide

This paper will follow the traditional Introduction, Method, Results and Discussion structure.

The Introduction chapter will start out by laying the groundwork for the motivation behind this paper – why it is being written and why the results are relevant. The literature review segment follows, which will determine the groundwork on which the rest of the paper will be based – what has already been written on the subject and what are the context and requirements for an upgrading technology, from the perspective of a Danish Investor

The Method chapter will specify which methods are being used, how they are defined, and which guidelines are being followed. It will also provide the assumption under which the analysis is conducted and describe the system details of each alternative technology.

The Results chapter will present the results of the models, divided into each alternative.

The Discussion chapter will compare the results and discus how they can be interpreted. This chapter will have a comparative angle and the intent is to determine whether the developing biotrickling filter is competitive with market leaders. It will also aim to uncover which, if any, advantages the developing technology holds. The chapter will then conclude whether - and under which circumstances - the technology can be considered a viable investment. The chapter will end the paper by providing recommendations as to what topic would be proper for further research.

Finally, it should be noted that the biotrickling filter is a developing technology, and the LCC and LCA methodologies do not claim to be precise. In order to provide some degree of certainty, the paper uses a probabilistic method. The results are being calculated using monte carlo simulations. Therefore, each model does not have a single result, but rather a probability distribution of as many as 10,000 different results. As such, when results are being presented and discussed in this paper, it is usually in the form of the average or median result, with the 5 and 95 percentiles acting as the margins of error.

All monetary values in this paper are presented as 2019 Danish Kroner (DKK), unless otherwise specified. When outside sources have used different currencies, these have first been adjusted for inflation – using the Us Inflation Calculator website or the Inflation Tool website as appropriate – then converted to Kroner at a conversion rate of 6.6522 DKK/USD and 7.4599 DKK/EURO.

This paper uses the terms upgrading, sweetening and enrichment in the context of biogas. In this paper “upgrading” refers to the removal of CO_2 from the biogas. “Sweetening” refers to the removal of H_2S from the biogas. “Enrichment” refers to the conversion of CO_2 to CH_4, by the way of hydrogen.

This paper uses the abbreviation BTF, which means Biotrickling Filter. In this paper, “BTF” merely refers to the technology of Biotrickling filters. When the paper uses the terms “BTF alternative” or “BTF technology”, it refers to the in-development biogas enrichment method. When the paper uses the term “conventional BTF” or any variation thereof, it refers to biogas sweetening by way of a biotrickling filter.

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Abbreviations	Meaning
β_E	Beta Equity
ρ_{H_2}	Density of hydrogen (H_2)
AD	Anaerobic Digestion
$AdminC_{ad,t}$	the administrative costs $[DKK$
$CC_{ChemAb,t}$	the cost of chemicals for the Chemical absorber alternative in the year t $[DKK]$
CO_2C_{tri}	Relationship between the CO_2 content and the methane content in the unupgraded biogas as a triangular distribution $\left[\frac{m^3_{H_2}}{m^3_{CO_2}}\right]$
CoE	Cost of Equity
COR	Corporate tax rate
CP_{Chemab}	The price of the chemicals $\left[\frac{DKK}{m3}\right]$
CPI	Consumer Price Index
CPI_s	Consumer Price Index for the scenario s $[-]$
CU_{ChemAb}	The chemical usage in a year $[m^3]$
DKK	Danish Kroner
$DPR_{a,t}$	Depreciation for the alternative a, in the year t
$EC_{BTF,a,t}$	The electricity cost for the BTF alternative for the assorted components in the year t $[DKK]$
$EC_{BTF,e,s,t}$	Electricity Cost of the BTF alternatives electrolyser, in the scenario s and year t
$EC_{HPWS,t}$	the cost of electricity for the HPWS alternative in the year t $[DKK]$
$EP_{s,t}$	Electriciy Price in the scenario s and year t
EU_{AD}	the electricity consumption for the AD plant $\left[\frac{kWh}{ton}\right]$.

$EU_{BTF,a}$	The electricity usage for the BTF alternative for the assorted components $[kWh]$
$EU_{BTF,e}$	Electricity consumption of the BTF alternative's electrolyser
$EU_{HPWS,tri}$	the electricity consumption for the HPWS alternative as a triangular distribution $\left[\frac{kWh}{m^3}\right]$
$FC_{s,a}$	Financing cost of the alternative a, in the scenario s
GJ	Giga Joule
HR_a	Heat requirement for the respective alternatives $\left[\frac{kWh}{m^3}\right]$
$H_2 2CO_2$	The hydrogen to CO_2 relationship in the BTF alternative
$HPWS$	High Pressure Water Scrubber
IEA	International Energy Agency
Ins_{ad}	the insurance cost $[DKK]$
$LC_{AD,t}$	the Labor Cost for the AD plant in the year t $[DKK]$
LIR_{uni}	Lending Interest Rate as a uniform distribution
LT_{com}	the expected lifetime of the respective components $[years]$.
LT_p	the expected lifetime of the project $[years]$
$M_{AD,t}$	the methane produced in the year t $[m^3]$
M_{Boiler}	the biogas burned in the boiler $[m^3]$
M_{Leak}	the biogas lost in the upgrading process itself $\left[m^3_{CH_4}\right]$
$M_{PB,s}$	The methane yield, "post boiler" for each alternative $[m^3_{CH_4}]$
$M_{PT,s}$	The methane yield, "post torch" for each alternative $\left[m^3_{CH_4}\right]$

M_{torch}	the biogas burned in the torch due to downtime of the upgrading technologies $[m^3_{CH_4}]$
$MC_{s,t}$	The cost of the maintenance service for the alternative as a triangular distribution [%].
MJ	Mega Joule [1,000,000 Joule]
MMC_{BTF}	The cost of the mineral medium for the BTF alternative $[DKK]$
$MMU_{BTF,tri}$	the mineral medium usage for the BTF alternative as a triangular distribution $[\frac{kg}{m^3}]$
$MP_{a,tri}$	The cost of the maintenance service for the alternative as a triangular distribution [%]
MRP	Market Risk Premium
$MY_{substrate}$	The methane yield of the respective substrates $\left[\frac{m^3}{ton}\right]$
$NBG_{sale,t}$	the upgraded biogas available for sale in the year t $[m^3]$
NPV	Net Present Value
NW_{AD}	the number of fulltime workers employed at the AD plant $[year\ employment]$
$OC_{ad,t}$	the office cost $[DKK]$
PC_a	Procurement Cost of the alternative a
PC_{com}	the procurement cost of the component in question $[DKK]$
PL_a	the percentagewise loss of methane for each of the alternatives [%]
PMM_{tri}	the price of the mineral medium $\left[\frac{DKK}{kg}\right]$
R	Risk-Free Interest Rate
RV_a	Resale Value of the alternative a
RV_{com}	the resale value of the component in question $[DKK]$

$SC_{AD,t}$	Cost of substrates used by the AD plant in the year t $\left[\frac{DKK}{ton}\right]$
$SF_{substrate}$	the percentage of total substrate use that is represented by each of the four substrates [%]
$SP_{substrate}$	the prices of the respective substrates $\left[\frac{DKK}{ton}\right]$
T	Lifetime of the project $[year]$
t	Respective year
TA_a	the technical availability for each of the alternatives [%]
USD	United States Dollars
W_{norm}	the yearly wages per post as a normal distribution $\left[\frac{DKK}{year\ employment}\right]$
$WC_{s,t}$	Water Cost for the scenario s, in the year t $[DKK]$.
WP_{norm}	Water price as a normal distribution$\left[\frac{DKK}{m^3}\right]$
WU_s	Water Consumption for the scenario s $\left[\frac{m^3_{water}}{year}\right]$
YSU	the yearly substrate usage $[tons]$

Introduction

Biogas is an energy rich mixture of primarily methane and CO_2, created from the anaerobic digestion of biomasses (Chunlan, Feng, Wang, & Ren, 2015, s. 541). The biogas can be used as an energy fuel, creating CO_2 that then may be captured in biomasses once again (Holm-Nielsena, Al Seadib, & Oleskowicz-Popiel, 2009, s. 5479). This cycle of carbon makes it an environmentally friendly alternative to fossil fuels, which introduces carbon to the atmosphere that originally was chemically stored in the fossil fuel.

In Denmark most biogas is produced from animal waste, especially slurry from the swine industry. Other biomasses, or substrates, are also used – the majority of them wastes from other industries. This makes the biomass production sustainable, as the majority of substrates were not produced as a consequence of the biogas – instead the biogas merely repurposes them. The biogas can then be used as is, to produce heat or electricity. Because of the high CO_2 content, usually 40 %, but sometimes as low as 30 or as high as 50 percent (Muñoz, Meier, Diaz, & Jeison, 2015, s. 3), the gas is not as energy rich as natural gas, which is almost purely methane. In order to remove this CO_2, and thereby increasing the energy content, the gas can undergo a process called upgrading (Sun, et al., 2015, s. 522).

Once this higher methane concentration, with its higher calorific value, has been reached, the biogas can become "natural gas quality with a high methane content" (Sikkerhedsstyrelsen, 2018). In Denmark this is legally defined in accordance with its content, the calorific value and the density. If these parameters are within the legal boundaries, the upgraded biogas may be sold as such and be injected into the natural gas infrastructure. Furthermore, the upgraded biogas can be sold with a government sponsored subsidy (Energistyrelsen, 2019), and buyers of the gas may additionally collect a subsidy if they use it for specific purposes, such as electricity production. This has the added advantage of allowing the bio-natural gas (BNG) to be stored for long period of time, something which the raw biogas cannot.

There are many different methods in which the carbon dioxide can be removed, but there are two market leaders: water scrubbing and chemical absorption, sometimes called amine scrubbing. The outright removal of carbon dioxide is useful and viable, but another option is to take advantage of its existence. Certain technologies inject H_2 into the upgrading process, combining it with the CO_2 to create CH_4. The addition of hydrogen enables not just the removal of the unwanted carbon dioxide, but its conversion to the desired methane. Furthermore, this relationship can be considered a form of energy storage – if the hydrogen is produced be electrolysis. In nations with a high degree of intermittent sources, such as Denmark with its many wind turbines for example, the renewable electricity can be used to produce hydrogen, which in turn can be used to enrich the biogas. This chain effectively allows the electrical power to be chemically stored in the methane and is one of the processes called Power-to-Gas.

This paper focuses on a developing technology that takes advantage of this hydrogenation process. In 2017 an article describing an experimental biogas upgrading method was publish

(Dupnock & Deshusses, 2017). This method injected hydrogen and biogas into a bio trickling filter, to allow micro organisms to convert the H_2 and the CO_2 in the biogas into CH_4 – thereby not only increasing the methane yield, but also upgrading the biogas at the same time.

This process is not free however, which raises the question if this process is financially viable. Does the value of the increase in methane yield outweigh the cost of the hydrogen injection? Would an investor be better suited by simply sticking to the conventional upgrading methods? These questions are further complicated by the changing nature of the context in which the technologies exist. One technology may be the most viable by the time an investment is to be made, but by the end of its life cycle, conditions may have changed. Price changes over time, legislative changes, the development and maturing of new technologies, changes in the supply chain and many more factors can affect the choice of which technology to invest in.

Any attempt to assess the financial viability of an upgrading technology, will have to include not only the acquisition and operations costs, but also a comparison to leading alternatives and, perhaps even more importantly, an analysis of an encompassing spectrum of scenarios. On top of this, as the biogas and upgrading technologies are motivated by a need for greener energy alternatives, a competing technology must also be environmentally friendly – if it is not, the entire purpose is defeated.

This paper aims to asses this new technology, using the Life Cycle Costing and Life Cycle Assessment methods. It will include the full scope of production and compare it to Water Scrubbing and Chemical Absorption which are the current market leaders.

The paper will take on the perspective of a Danish investor, who invests into a biogas plant in the year 2020. The plant will reach completion in 2021 and for the following 20 years it will take on 360,000 tons of substrates a year, in order to produce biogas. The biogas will be upgraded with one of the three alternatives. The paper will gauge which of the three makes for the most viable investment, both financially and environmentally.

The Life Cycle Costing method aims to assess the financial viability of the technology as an investment, while the Life Cycle Assessment method aims to gauge the environmental consequences of implementing the technology. Between the two methods, the paper ought to give an insight into whether the new technology can be considered to be competitive with the market leaders.

Literature

To ensure that this paper does not retread paths that has already been explored by others, and to summarize the groundwork onto which this paper is built, a literature review is required.

For this purpose, a Systematic Literature Review (SLR) was conducted in accordance with the guidelines set by Okoli & Schabram (Okoli & Schabram, 2010). A SLR consists of four stages, with each stage containing 2 processes. By the end of the eight total processes, the SLR ought to result in a solid introduction to the current state of academic writing on the chosen subjects.

The first stage, "Planning", consists of Purpose and Protocol: First decide upon the purpose of the SLR and then determine how to go about it. For this paper, four key research questions were formulated: "What is the state of biogas in Denmark", "What is the state of biogas upgrading technologies; which are considered the most competitive and why?", "How is an LCC conducted" and "What is the state of the Biotrickling filter technology". The protocol decided upon was to use the Google Scholar and Science Direct search engines. For the first research question, especially when it came to legislative matters, the conventional Google search engine was also used, as many relevant sources were not the product of academic writing.

The second stage, the selection stage, consists of the literature search and the screening. The search itself consisted of utilizing the decided upon search engines, by using a decided upon list of search terms. If a source was later determined to be of particularly high relevance, this step was sometimes revisited, by looking at which papers cited that relevant source. The screening is the initial step for determining which of the sources were relevant. In this paper the screening consisted primarily of reading the title of the paper and gauging if the article were relevant to the topic at hand. When a search term had provided a large number of results, the screening also stopped after the first 100 results, as the search engines presented the results in a descending order of relevance. The source was also discarded if it was not written in a language the writer did not understand.

The third stage consist of the quality appraisal and the data extraction. The Quality Appraisal goes a step further than the screening, but has the essential same function namely, to determine what is relevant for the purpose of the research questions. This consisted of reading the abstract or summary of the source, or in lieu of these, the source itself, until the question of relevance could be answered, starting with the ones who initially appeared to have the highest relevance. Sometimes a source was discarded due to age – if the source predated the year 2000 and a more recent paper detailing the same subject was available, the earlier source was discarded. Finally, some sources were discarded if they did not live up to the ordinary criteria for source selections, e.g., if they appeared to have been written with clear commercial or political motive. The data extraction consisted of creating a writing a word document with tables corresponding to each of the research questions. If a source had passed the appraisal, it went into the corresponding table, and read. Each source was then joined by a small text detailing the essence of the source, as far as its relevance to the research questions.

The third stage consists of the synthesis of the studies and actually writing the review. The synthesis consisted of taking the small bits of text written in the extraction phase, and synthesizing them into parts of coherent text, which aimed to answer the research questions. The writing of the review consisted of rearranging and editing said bits of text, thereby constructing the remainder of this chapter.

Biogas in Denmark

Biogas is the name of the particular mixture of methane and carbon dioxide that occurs as a product of the bacterial digestion in an oxygen free – anaerobic – environment of organic materials (Angelidaki, 2018, s. 452).

Denmark has produced biogas, based on waste products from its pig farms, for many years. In the year between June 2017 and June 2018, upgraded biogas represented 8 percent of the total amount of gas in the natural gas network in Denmark (Naturgasfakta, 2019).

In general, two types of plants exist in Denmark, farm scale plants and joint plants. In the former, the plant is built by a farmer who utilizes the waste from his or her own production. In the latter case, the plant receives waste from several farmers, with some using other sources as well, such organic waste from other industries or energy crops (Lybæk & Asai, 2017). Denmark has been a pioneering nation of this type of plants (Holm-Nielsena, Al Seadib, & Oleskowicz-Popiel, 2009, s. 5480). In both types of plants, the waste product in store in a tank in an oxygen free environment in either mesophilic (30-40 degrees C) or thermophilic temperatures (53-58 degrees C) for 12 to 25 days.

The biogas that is produced is a mix of methane (50-70 % concentration) and carbon dioxide (30-50 % concentration), with lesser concentrations of hydrogen sulphide, nitrogen, oxygen, water vapors and ammonia (Angelidaki, 2018, s. 452). Of all these components, only the methane is wanted. With carbon dioxide being the second largest contributor, it is desirable to lover its concentration – the lover the carbon dioxide content, the higher the methane concentration, and with that follows a higher calorific value. This increase of the methane concentration of biogas is called biogas upgrading.

Once the waste products have been degassed, what remains is liquid called digestate. This digestate can be used as a fertilizer, in the same way manure usually is. The nutrients that exist in the manure still remains in this digestate, but the nutrients are even more accessible to the crops, and the digestate is less odorous (Lybæk & Asai, 2017, s. 132). Farmers are restricted by to how much digestate they are allowed to spread. They only receive back the allowed amount, with the remainder usually being sold to other crop farmers in the area (Holm-Nielsena, Al Seadib, & Oleskowicz-Popiel, 2009, s. 5480).

Biogas in Denmark has been produced for decades but has seen a dramatic growth in recent years. The production doubled between 2015 and 2017, and is expected to grow even further. The reason for this boost in production has been cited as political support, in particular the energy agreement of November 2013 (Seadi, 2017).

Legal Requirements and Subsidies

This section will describe the Danish legislation as it stands in the year 2019, to the extent that it is relevant to this paper. It will not attempt prediction as to the direction in which said legislation is headed. This paper does not consider it possible to say which laws may be changed or in what way – instead, the consequences of legislative changes will be accounted for in the scenario part of the analysis, to be described in the section of the same name: Scenarios.

Only the laws and proclamations that have been found to be relevant are included, and only the relevant parts. A text is found to be relevant if it may affect the final costing of the technologies.

As stated in the introduction, biogas is considered to be of natural gas quality, if it has sufficiently high methane content. This is defined in the proclamation "*Bekendtgørelse om gaskvalitet*" from the Danish Safety Tecnology Authority (*Sikkerhedsstyrelsen*) from 2018. This proclamation defines "bio-naturalgas" as biogas that has been upgraded to natural gas quality (Sikkerhedsstyrelsen, 2018, s. § 2). It further defines natural gas quality as having an upper Wobbeindex of 50.76-55.8 MJ/Nm^3 (Sikkerhedsstyrelsen, 2018, s. § 14 stk 2) and a relative density[1] of minimum 0.555 and maximum 0.7. It further states that the concentration of hydrogen sulphide must not exceed 5 mg/Nm^3 (Sikkerhedsstyrelsen, 2018, s. § 18). The proclamation also dictates that the gas must be odorous, so as to help in detecting any leakages (Sikkerhedsstyrelsen, 2018, s. § 30). It further adds, that in the case of biogas, an odorant must be added, if the biogas has been cleansed for contaminants such as hydrogen sulphide or water (Sikkerhedsstyrelsen, 2018, s. § 33 stk 2). These odorants can be THT or thiols ("*Merkantater"*) – if others are used, the Danish Safety Technology Authority must permit it. These are the minimum requirements that any prospective technology needs to accomplish. The proclamation does not specify any requirements for methane content, although this is indirectly dictated by the Wobbe index. This means that the upgrading technology needs to accomplish this much – any less and the biogas fails to qualify as natural gas quality, which negates the entire rationale behind upgrading. Furthermore, due to the requirements for low hydrogen sulphide concentration an added cost is required for the cleansing and the odorants.

[1] The proclamation also defines "relative density" as "the relationship between the mass of equal volumes of gas and dry air, under the same presures and temperature". ("*Forholdet mellem massen af lige store rumfang gas og tør luft ved samme tryk og temperatur*") (Sikkerhedsstyrelsen, 2018, s. § 2, 14)).

As stated previously, biogas with natural gas quality qualifies for a number of subsidies. These are documented in a number of different laws and proclamations. The first is the proclamation the Danish Energy Agency (*Energistyrelsen)* from 2016[2]. This proclamation refers to previously mentioned definition of sustainable biogas. It further adds, that in order to remain sustainable, that any biogas used for transportation cannot be produced on crops that could have been used for food (Energistyrelsen, 2016, s. § 6 stk 2). It states that any purchaser of the sustainable biogas is to contact the agency, once a year, to apply for the subsidy (Energistyrelsen, 2016, s. § 7). The agency will then conclude whether the purchased gas was produced sustainably and pay accordingly.

Finally, and most importantly for this paper, is the law detailing the subsidies for the producer of upgraded biogas the natural gas law (*lov om naturgasforsyning*) (Energistyrelsen, 2019). It specifies that the BNG producer has claim on a threefold subsidy. The first subsidy is inflation dependent, equal to 79 DKK/GJ, to be increased each year on the firs of January by 60 percent of the net increase of the consumer price index (Energistyrelsen, 2019, s. § 35 c, stk 2). The second subsidy is dependent on the natural gas price, equal to 26 DKK/GJ. Each year the average natural gas price is determined – the subsidy will decrease by an amount equal to the amount that the natural gas price is above 53.2 DKK/GJ. Likewise, if the price is below that amount, the subsidy will increase accordingly (Energistyrelsen, 2019, s. § 35 c, stk 3). The third subsidy is time dependent and will reach zero at the end of 2019, and remain so, from there on out. As the investment detailed in this paper will begin in 2020, this part of the subsidy will not be relevant (Energistyrelsen, 2019, s. § 35 c, stk 5).

Many of the above proclamations were made relatively recently within a few years. This could be an indication of further, future changes – however, as stated, it is beyond the scope of this paper to speculate on the details of such future changes. Instead this paper will attempt to accommodate the eventual consequences of such changes, via the use of scenarios.

Energy Crops

Biogas producers can increase their yield by using energy crops in their production, which have higher methane yield per mass than slurry does. Denmark, however, is currently in the process of reducing this practice. In order to qualify for “sustainable” biogas production, and thereby qualify for the subsidies and grants that follow that distinction, the biogas must be produced primarily on waste products (Energistyrelsen, 2015, s. § 3). Only a minority of the gas may stem from energy crops – a maximum of 25 % in the period the 1st of August 2015 to the 31st of July 2018, and a maximum of 12 % in the period the 1st of August 2018 to the 31st of July 2021 (Energistyrelsen, 2015, s. §3, stk 2-3). No law is currently in place to regulate the percentage after this date, but it is “expected” to be even lower (Energistyrelsen, 2012). The motivation behind this is to reduce greenhouse gas emissions. Using animal waste is advantageous in that regard, as this reduces the emissions of methane and nitrous oxide by

[2] ”The Proclamation of subsidies for biogas, which is sold to transportation, used in process porpuses i corporations or uses for heat production”. ”*Bekendtgørelse om tilskud til biogas, der sælges til transport, benyttes til procesformål i virksomheder eller anvendes til varmeproduktion*”

the agricultural industry. By using energy crops instead, that advantage is lessened (Energi-Forsynings- og Klimaministeriet, 2018, s. 17).

Biogas upgrading technologies

There are several types of biogas upgrading technologies – they can as a whole be divided into two axes – CO_2 removal versus hydrogenation and physical/chemical methods versus biological. On these axes, upgrading via a BTF would be a biological hydrogenation technology.

Several review articles already exists to compare the various upgrading technologies (Muñoz, Meier, Diaz, & Jeison, 2015) (Sun, et al., 2015) and their costs. Common for these are that they conclude that cost is inherently tied to production capacity – the cost per kWh at one production capacity is different and incomparable to that of another, and costs can vary wildly. It is therefore not sufficient to transfer a result from one context to another and expect it to be equally valid. Furthermore, there is no singular "correct" choice of technology that applies to all producers. Instead, the correct choice is based on a number of factors, including production capacity and the economic reality of the owner.

Water scrubbing in particular is a technology that has seen wide industrial use (Hoyer, Hulteberg, Svensson, Josefina, & Nørrgård, 2016, s. 18). It is the industry standard, and often the first to be discussed in any comparative analysis. This trend is changing however – in Denmark chemical absorption has taken the lead, representing 43 percent of the installed capacity in 2017, compared to the 38 percent of water scrubbing (Kvist, 2018, s. 8).

This paper has attempted to summarize the differences between the various technologies, in accordance with the reviewed literature[3]:

Table 1 - Comparison between the Advantages and Disadvantages of different biogas upgrading technologies

Technology	Advantages	Disadvantages
Water Scrubbing	High purity of gas is possible, installations are easy to operate and maintain, tolerant for trace impurities in biogas, no chemicals are needed, low biogas loss (Budzianowski, Wylock, & Marciniak, 2017). Hydrogen	Clogging due to bacterial growth is possible, high power requirements, low flexibility in regard to production capacity, capital and O&M costs are "significant", CO_2 water corrosion may shorten plant lifetime (Budzianowski, Wylock, & Marciniak, 2017).

[3] Some of the papers disagree – one source, for example, states that scrubbing using organic solvents leads to a high methane loss, while most specify that the methane loss is almost negligible. In these cases, both viewpoints have been included in the table.

	sulfide removal is possible (Hjuler & Aryal, 2017, s. 9)	Removal of hydrogen sulfide prior to upgrading is "Highly Recommended (Muñoz, Meier, Diaz, & Jeison, 2015, s. 8). The process is slow and leaves small amounts of O_2 (Hjuler & Aryal, 2017, s. 9)
Physical Absorption using organic solvents	Higher solubility than with water and removal of hydrogen sulfide is possible (Angelidaki, 2018). Low methane losses (>0.1%) (Hjuler & Aryal, 2017, s. 9)	Solvents are difficult to regenerate, and removal of hydrogen sulfide requires higher temperatures (Angelidaki, 2018). "High losses of CH_4" (Sun, et al., 2015).
Chemical Absorption using amine solvents	Complete removal of hydrogen sulfide is possible, a methane content of 99 % is possible, methane loss is low (Angelidaki, 2018). Regeneration of amine solvents is possible and operation is cheap (Ryckebosch, Drouillon, & Vervaeren, 2011)	Solvents are toxic to humans and environment, and energy is required for regeneration of solvent, solvent are costly and prone to evaporation (Angelidaki, 2018). Investment is expensive, and corrosion may occur during operation (Ryckebosch, Drouillon, & Vervaeren, 2011). "Further chemical waste treatment is necessary (Hjuler & Aryal, 2017, s. 9)
Pressure Swing absorbtion	Low capital costs, low energy requirements and equipment is compact (Angelidaki, 2018). Removal of hydrogen sulfide is possible (Sun, et al., 2015). Relatively quick start up and installation (Hjuler & Aryal, 2017, s. 9)	Up to 4 % of methane can be lost during operation (Angelidaki, 2018). Expensive in investment and operation (Ryckebosch, Drouillon, & Vervaeren, 2011).
Membrane Separation	Can be used for hydrogen sulfide removal (Sun, et al.,	The membranes are costly and fragile, with an expected

	2015). Construction and operation are simple (Ryckebosch, Drouillon, & Vervaeren, 2011). Installation and startup is fast, production output is flexible, “purity and flowrate can vary”, low energy requirements, high methane purity (>96 %) is possible, low methane loss (Hjuler & Aryal, 2017, s. 9)	lifetime of 5-10 years (Angelidaki, 2018). High methane purity can only be achieved with high methane losses (Sun, et al., 2015). “Low membrane selectivity”, “consumes relatively more electricity per unit of gas production”, “Often yields lower methane concetration, though high purity is possible” (Hjuler & Aryal, 2017, s. 9)
Cryogenic Seperation	Can produce “almost pure biomethane (>97%)” (Angelidaki, 2018). Removal of hydrogen sulfide is possible (Sun, et al., 2015). CO_2 can be reused after separation, low methane loss, liquid methane allows for easy distribution (Hjuler & Aryal, 2017, s. 9)	High investment costs, methane loss and the equipment can be clogged during operation (Angelidaki, 2018). Many different components are required, e.g. heat exchanger, compressor, cooler (Hjuler & Aryal, 2017, s. 9)

In summary, a biogas upgrading technology need to be more than just profitable to be competitive – an ideal technology needs to compare favorably to its competitors. Naturally the choice is also affected by the availability of the technology – if no supplier exists in the country in question, that might very well be a deciding factor (Ryckebosch, Drouillon, & Vervaeren, 2011).

Biotrickling filters have been used in the biogas industry previously and both LCC and LCA’s have been performed (Cano, Colón, Ramírez, Lafuente, & Gabriel, 2018). The filters, however, were used for removal of hydrogen sulfide, rather than CO2, and is therefore an example of biogas cleaning, rather than biogas upgrading. Any results are therefore not analogous with the technology that is being investigated in this paper[4].

[4] According to a heuristic estimate made by supervisor Lars Yde, at supervisor meeting on the 13th of February, 2019.

LCC - Definitions

An LCC has been defined as "… a method of analysis used when quantifying the costs related to a production system or a product during its life cycle" (Dahlen & Bolmsjö, 1996).

There are structural similarities with an LCA, namely the life cycle perspective and the tools used for estimation. The two methods have in fact been combined in the past to assess the full range of consequences of a project (Norris, 2001), be they economic or not. In general, however, the two methods are separate, different in both purpose and methodology.

There is no universally accepted method of conducting an LCC, although several suggestions for a formal methodology have been made (Durairaj, Ong, Nee, & Tan, 2002). The reason for this appears to be based in function; there are many different applications of an LCC, and any universal method would have to be applicable to all of them. For example, an LCC method constructed for the purpose of a military investment, such as the one detailed by NATO (NATO, 2009), would differ from one intended for a construction project.

The literature differentiates between 3 (sometimes 4) types of LCC: The conventional LCC (or financial LCC), the Environmental LCC and the societal LCC (Hoogmartens, Van Passel, Van Acker, & Dubois, 2014). The conventional LCC is centered on the perspective of an investor, and only the cost born by the investor is considered, ignoring environmental costs. The environmental LCC include internalized monetized environmental costs, such as CO_2 taxes and waste disposal costs. The societal LCC includes all costs incurred, by the investor as well as society as a whole, monetizing and including aspects as human health and wellbeing. Common for all LCC's, are that all costs are monetized – they use a single metric, being money, as opposed to the LCA where several different impact categories, each with their own metric, can be assessed.

In this paper, the two will not be combined into one – instead they will be treated entirely separately.

Most LCC methodologies agree that costs can be differentiated into different phases - which phases are included varies, but the most common are Procurement/Acquisition/Production, Operation/Utilization and Retirement/Disposal/End of Life (NATO, 2007, s. 2-1) (Fabrycky & Blanchard, 1991) (Woodward, 1997, s. 336). While the names differ, they cover more or less the same phases, although there is some differentiation about which costs are included in which phase. Some include the pre-acquisition phases Conceptualization and R&D (NATO, 2007, s. 2-1) .

This paper will consider the following phases: Conceptualization, R&D, Procurement, Operation and Retirement.

The motivation for an LCC is, that many investors makes purchases based primarily on acquisition cost (Fabrycky & Blanchard, 1991). This would ignore the costs incurred over the lifetime of the project – operation, maintenance, cost of transport and recycling/scrapping etc., the sum of which can easily outweigh the acquisition cost.

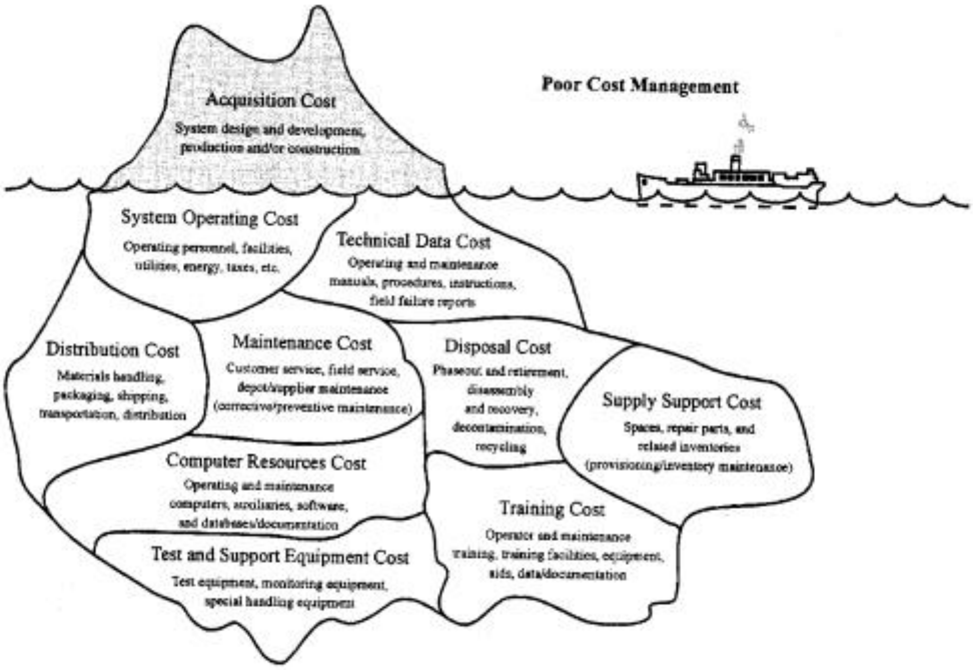

Figure 1 - Illustration of how Acqusition Cost differs from Life Cycle Cost, and why an LCC analysis can be important - (Fabrycky & Blanchard, 1991)

One point that is emphasized by several authors is that LCC’s can be used for cost minimization endeavors. In this case the investments being compared are different configurations of the same production, for example whether to invest in an initially more expensive part to avoid heavier maintenance costs later (Woodward, 1997) (Westkämper & Osten-Sacken, 1998, s. 354).

This paper will not attempt cost minimization – the alternatives being considered are three different upgrading technologies, essentially making up three different investments, and the end result will be a net present value for each investment.

There is some inconsistency when it comes to terminology, as was the case with the different aforementioned phases. Some considers LCC synonymous with terms like Whole Life Costing (Gluch & Baumann, 2004, s. 573) or Total Cost of Ownership (Farr & Faber, 2018, s. 5), while for some, for example NATO, they consist of entirely separate methods.

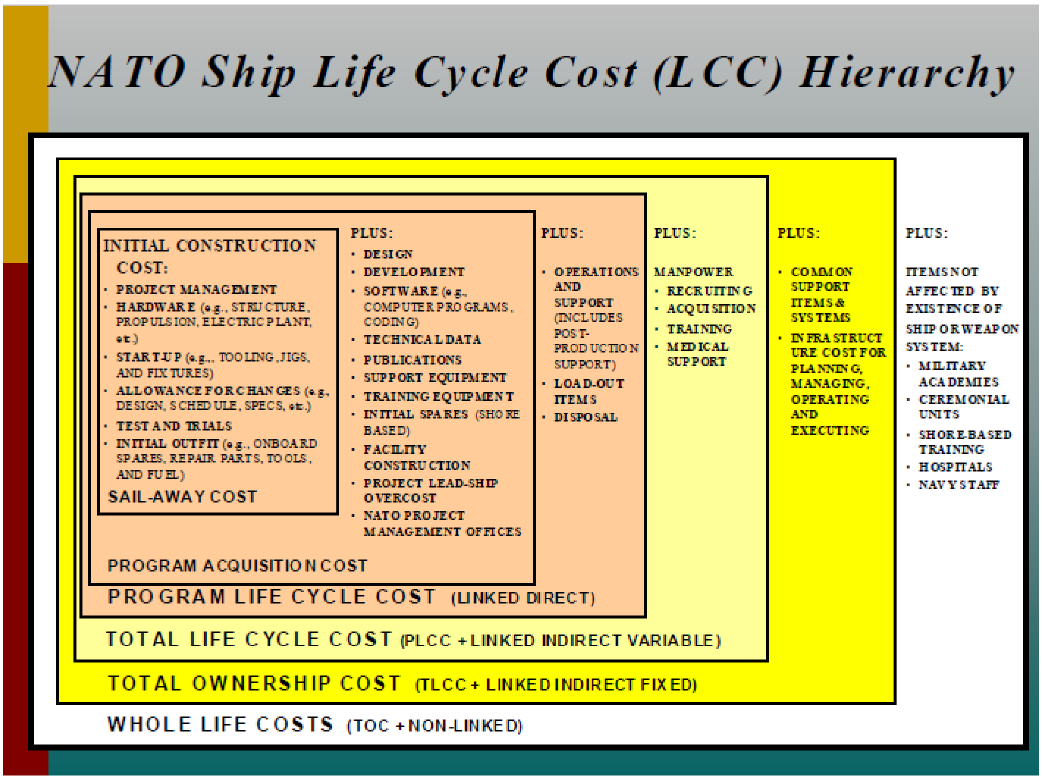

Figure 2-3: Typical Life Cycle Cost Boundary.

Figur 1 – The differences LCC and similar terms (NATO, 2007, s. 2-5)

While an LCC might include fewer costs than TOE and WLC it is still recommended for the purposes of comparison between alternatives (NATO, 2007, s. D-4).

There are four generally accepted cost estimation methods (Farr & Faber, 2018, s. 13): 1) Engineering cost method: where the cost of each element in the project is estimated, 2) Cost Accounting: “modern cost management systems to track and allocate expenses”, 3) Analogy: a comparison to a similar, historical project and 4) Parametric: based on a relationship between cost and a project related parameter.

This paper will make use of three of these: Parametric, Analogous and Engineering costing method.

An LCC is only an estimate, and the earlier the LCC is performed, the more assumptions are necessary and the more uncertain the estimate becomes (Farr & Faber, 2018). An LCC relies on the data that is available at the given time, and if a phase is not yet concluded, it is likely that accurate data does not yet exist. An LCC will therefore always rely on a certain amount of assumptions. Naturally, assumptions have a certain uncertainty attached to them, and consequently so will any LCC relying on them. The further into an investment one waits before making an LCC, the more data is available and the more accurate the analysis will become.

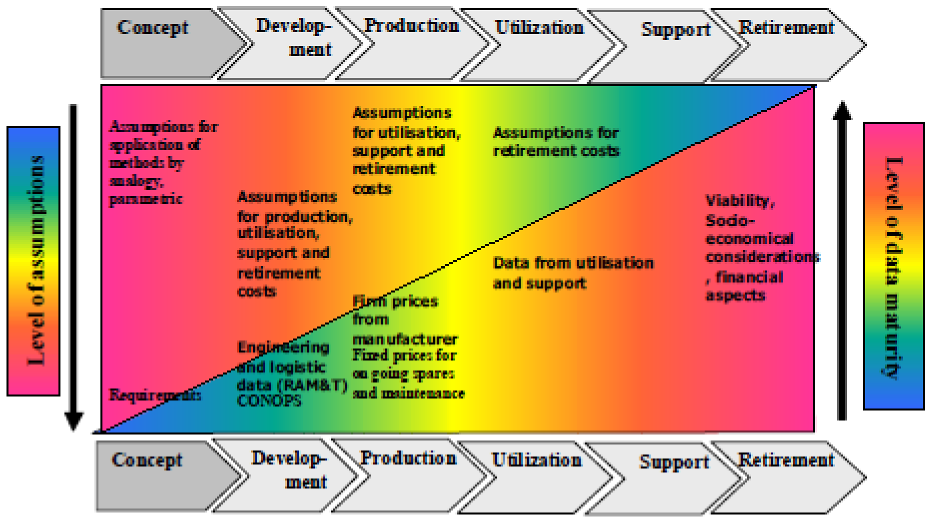

Figure 2 - Diagram detailing the relationship between data maturity as the project is developed versus the assumptions needed for an LCC

Conversely however, by that time it may very well be too late in the process to alter the outcome of the investment (Farr & Faber, 2018, s. 14). Therefore, it can be recommendable to conduct an LCC early in the process and revisit and update it periodically with newly acquired data.

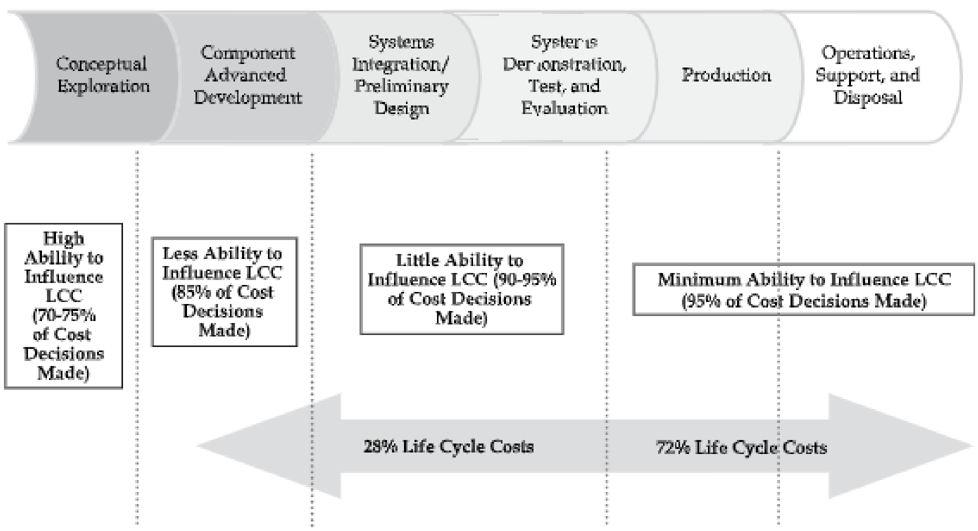

Figure 3 - Figure detailing the ability to influence project costs in accordance with the phases of the project

An LCC performed before acquisition may very well turn out to be inaccurate, but it will provide a documented basis on which a decision can be made. In any point, an LCC should not be considered to be accurate. The purpose of an LCC is to give insight and support to a decision-making process, not to be the decision-making process itself.

That is not to say that it is impossible to somewhat counter said uncertainty. This does require that one can identify the primary causes of uncertainty and assess the full scope of its consequences – the risk. Once the critical parameters have been identified, the full range of possible outcomes must be examined, and their consequences calculated. The NATO guidelines recommend using Monte Carlo simulations (NATO, 2007, s. 4-3) to account for uncertainty and scenario analysis to conduct sensitivity analysis (NATO, 2007, s. 7-11).

This paper will make use of Monte Carlo simulations – this process will be described in the Probabilistic Costing section.

In conclusion – the literature does not agree on a single method. Instead many exists for different purposes. None has been found that specifically caters to energy investments. Instead a method will be constructed from several sources, that fit the purposes of this paper.

Biotrickling Filter

BTF's work by allowing a gas – for example biogas – to pass through chemically inert material. Microorganisms grow upon the surface of the material, using the gas as a source of energy. Depending on the type of microorganism, different gasses would be consumed, allowing for range of applications, from removal of hydrogen sulfides (Fernández, Ramírez, Manuel, & Cantero, 2014, s. 529).

In the context of biogas, the technology has been successfully applied for the purpose of removing hydrogen sulfide (Fernández, Ramírez, Manuel, & Cantero, 2014, s. 529). Suggestions have been made however, for an alternative usage, namely biogas upgrading. It is this method which is the focus of this paper.

In 2017 an article was published detailing an experimental setup of a bio trickling filter to enrich biogas (Dupnock & Deshusses, 2017). The method used Hydrogenotrophic Methanogens to reduce CO_2 concentrations via the injection of hydrogen. The article estimates that using the specified method would allow for the upgrading of biogas to 90 % methane content at a rate of 90 m^3 of biogas per m^3 reactor per day (Dupnock & Deshusses, 2017, s. 498), a result which earlier, similar experiments had not achieved.

The technology works via the following stoichiometry:

Equation 1 - Stoichiometry of Hydrogenotrophic Methnaogens (Dupnock & Deshusses, 2017, s. 489)

$$4\,H_2 + CO_2 \rightarrow CH_4 + 2\,H_2O$$

As such, for every CO_2 molecule, four H_2 molecules are needed and one CH_4 molecule is created. The research indicated that the actual consumption of H_2 were in fact slightly larger, as some of the gas – and some of the CO_2 – might have been used for cell growth in the BTF (Dupnock & Deshusses, 2017, s. 493). This paper will assume that all H_2 and CO_2 is consumed purely to create CH_4. This paper assumes that in a plant scale reactor, the amounts of H_2 and CO_2 are so great, that any consumption from the microorganisms can be covered by the uncertainty of the CO_2 content.

As a 90 % methane purity falls short of the Danish legal requirement to qualify for natural gas quality detailed above (see the Legal Requirements and Subsidies section) – which is the primary motivation for biogas upgrading. Therefore, the gas would need further upgrading, either by the technology accomplishing more efficient CO_2 removal, or by the subsequent use of a different technology. Likewise, the technology does not simultaneously remove hydrogen sulfide, as this would require the use of different microorganism in the filter. Hence, the cleansing of the hydrogen sulfide, either pre or post upgrading is required.

In December of 2018 a pilot project, researching this very method of biogas upgrading, was granted 16.6 million DKK from the EUDP (*Energiteknologiske Udviklings og Demonstrationsprogram)* (Wittrup, 2018). The project is conducted in coorperation between the Danish companies Nature Energy, Biogas Clean, the Technical University of Denmark (*DTU*), the University of Southern Denmark (*SDU)* and *Miljøforum Fyn*. It is this experimental setup which has motivated this paper. However, as that program has yet to be concluded, no data from it yet exists. As such, this paper will base its models on the original experiment.

Table 2 - Advantages and Disadvantages of the BTF technology

Advantages	Disadvantages
No methane loss (Dupnock & Deshusses, 2017, s. 489)	Low methane purity (90 %) has been proven to be consistent as of yet, necessitating secondary method to reach natural gas quality.
The use of hydrogen allows for Power to Gas	Hydrogen Sulfide removal is not possible
It is a biological method which does not necessitate the use of chemicals.	If chemical absorption is used as the secondary upgrading technology, chemical will be used anyways.
The biogas enrichment will increase the methane yield, allowing for a greater NBG production per substrate intake.	The technology is highly reliant on hydrogen from electrolysis, meaning that it is only as cheap and environmentally friendly as the electricity market is at a given time.
As CO_2 is being converted to CH_4 rather than being released after upgrading, the	

technology has very good opportunities for a low carbon footprint per m^3 of BNG.	

Method

LCC

No single methodology was found to be exhaustive for the purposes of this paper – therefore several different sources have been used to construct a makeshift methodology. The main sources for methodology are the NATO sources (NATO, 2007) and (NATO, 2009), as these are among the most detailed and flexible – they appear to be constructed with a wide range of different projects in mind, allowing for a range of different tools to be used.

The method followed in this paper will consist of the following steps:

1) Establish the boundaries of the project in question, so as to define which costs of which project is being estimated. This is done in the Boundaries section.

2) Establish alternatives to the project in question, in order to give a comparative perspective to the analysis. This is done in the Alternatives section.

3) Establish a work breakdown structure for each phase of the alternative systems, in order to determine which cost incurring elements are to be included. This is done in the Work Breakdown Structure section

4) Establish how each cost incurring element is to be estimated. This is done in the Assumptions section.

5) Establish how uncertainty is to be included in the estimate. This is done in the Probabilistic Costing and Scenarios sections.

6) Estimate all costs and discount them into a net present value. This is done in the OpenLCA and Excel software programs: OpenLCA is used for the static elements such as the Procurement and Retirement phases, while Excel is used for the time dependent elements in the Operational phase. The results of these are presented in the Results chapter

7) Compare the results of each alternative and scenario. This is done in the Discussion chapter.

8) Make a conclusion as to the financial viability of the project, and recommendation for a prospective investor. This is done in the Conclusion section.

Boundaries

In this chapter the boundaries of the LCC will be defined, completing step 1 of 8 of the LCC.

In accordance with the NATO guidelines for LCC methodology, three boundaries must be defined (NATO, 2007, s. 2_4).

The first boundary definition is the project itself; how is the system defined and what function does it fulfill. The second boundary condition is related to the timescale; when do the different phases of the project begin and end. Finally, the third boundary condition is the scope of the study: namely which elements, components and costs are included, and which are not.

First Boundary Condition

The project of interest is a joint biogas plant on the Danish island of Funen. As stated in the literature review, upgrading technology usually operates in conjunction with a biogas plant in Denmark. As will be pointed out in the assumptions chapter, the operation of the Anaerobic Digestion plant and the operation of the upgrading plant cannot be separated. A potential investor can therefore not simply compare the costs of the upgrading technologies themselves but need to look at the full picture – this means including the Anaerobic Digestion plant into consideration.

The biogas plant will take on 360,000 tons of biomass a year – this number is comparable to the Danish TSO's Technology Catalogue for renewable fuels, which uses 365,000 tons (Energinet, 2019), and it is equal to the projected consumption of a new constructed biogas plant on funen – Nature Energy Midtfyn, which is expected to take on 360,000 tons a year (Henriksen, 2015, s. 2), and to the amount used by COWI in their business case (Laugesen, 2013, s. 16). As such, this can be considered a realistic figure, and it will allow for a comparison with published results.

The biogas plant will take on biomass from nearby producers, produce biogas via anaerobic digestion and upgrade it to natural gas quality, via one of the three alternative technologies. The upgraded biogas will then be injected into the natural gas network and sold.

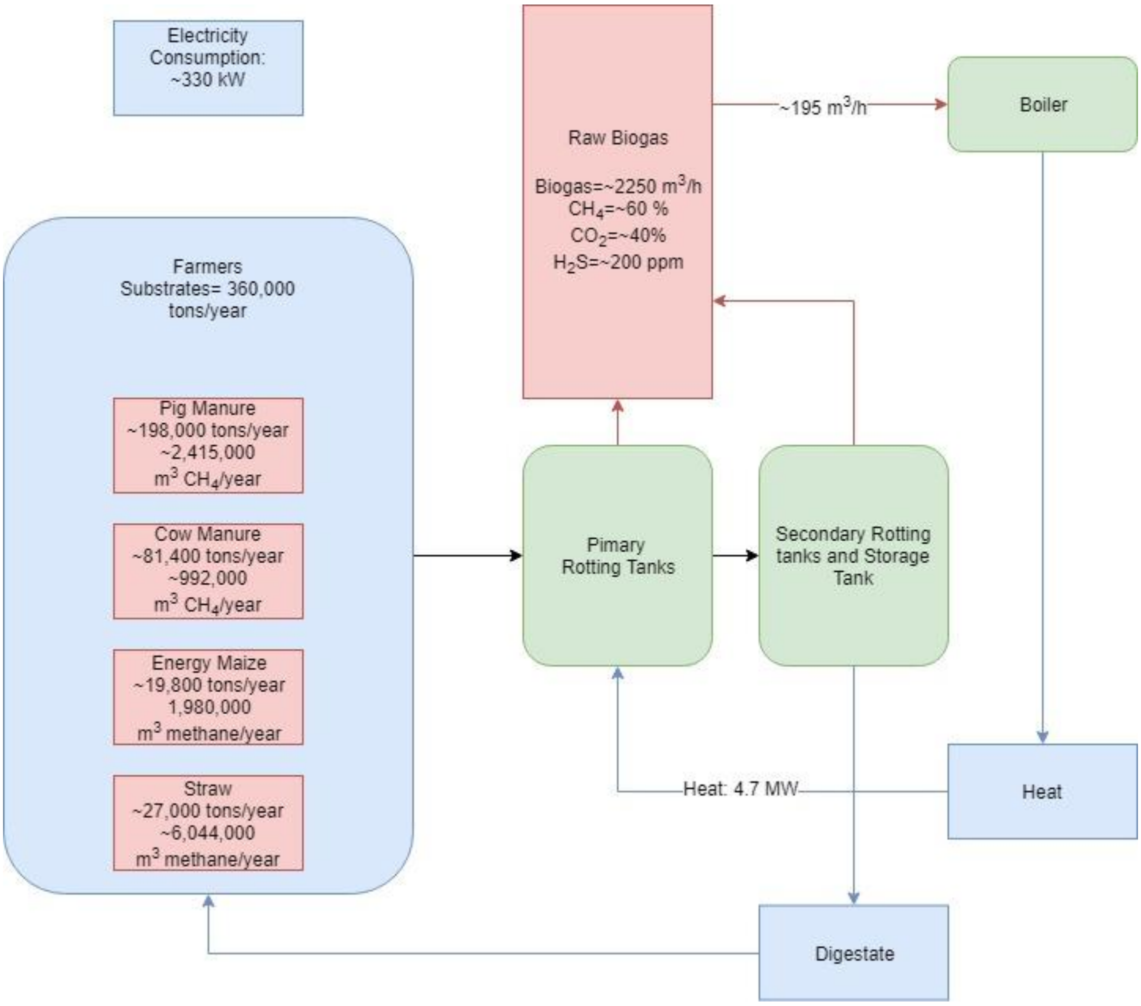

Figure 4 - Conceptual Schematic of the AD plant - Red denotes flow of biogas, blue denotes other resource flow and green denotes internal production components

Second Boundary Condition

The second boundary condition relates to the timescale of the project. In this model, plant construction will begin in 2020 and take 1 year. After that the plant will operate for 20 years, in the years 2021-2040. After that it will be deconstructed in accordance with common practices. Deconstruction is assumed to take place at the end of year 2040.

Third Boundary Condition

The third boundary condition is the scope of the study. Life Cycle Costing includes all costs incurred during the Life Cycle of a project. As stated in the literature review, this paper divides the costs into Conceptualization, R&D, Procurement, Operation and Retirement.

The investor will not be involved in the Conceptualization or R&D of any of the alternatives. This assumes that a prospective investor in a biogas plant will procure the finished upgrading technology from a third party, as opposed to develop it themselves. Therefore, any costs incurred during development will not be considered by the LCC[5].

The LCC will assume that all Procurement costs will be paid be the investor. This includes the construction of the plant and upgrading facilities, as well as any cost incurred by the decision to construct and operate a biogas plant.

This includes the production facilities themselves, as well as facilities required for daily operations, such as personnel and storage facilities, as well as the power and natural gas connections which will be needed to connect the biogas plant to the national grid. It will also include immaterial procurement costs, such as insurance, installation and consulting fees.

The LCC will also include Operational and utilization costs, including fuel use, labor costs, administrative costs and maintenance costs. As the result of the LCC is a Net Present Value, this phase also includes the main source income associated with the project, namely the sale of upgraded biogas[6].

The LCC will also include the so-called Retirement costs, including the resale value of the components after use.

As the LCC will consider the costs associated with the decision, the LCC will not include any cost incurred before the decision was made – for example any planning or projecting cost. Nor will it include any costs that are not associated with ownership, such as costs incurred by municipal or state governments or by the buyers of the biogas.

A complete list of the cost incurring components will be included in the Work Breakdown Structure chapter.

Alternatives

This chapter will take care of part 2 of 8 of the LCC, establishing the alternatives.

The primary motivation of this paper is to gauge the viability of the BTF technology as a biogas upgrading option. In order to do that however, alternatives need to be analyzed under the same conditions and assumptions, in under to supply a basis of comparison. In that way, the technology can be tested for not only viability but for competitiveness.

The two technologies that will be compared are the two most widely used technologies. As mentioned in the literature review section, the two current industry leaders are the High-Pressure Water Scrubbing (HPWS) option, which for long has been considered the

[5] This choice was made after consultation with supervisor Lars Yde on the 13th of February 2019

[6] This paper does not include the sale of digestate, even though this is possible. There are two reasons for this – firstly, no source could be found that adequately describes how much digestate could be assumed sold. Secondly, the aforementioned COWI business case does not include the sale of digestate (Laugesen, 2013), suggesting that if any amount is sold at all, it would not be enough to affect the final result.

economically most viable option, and the Chemical Absorption option which in recent years has represented the majority of newly built plants.

The first step, however, will be to define the BTF technology, as it pertains to the LCC.

BTF

As the technology is still in development, the data maturity is not very high. As was established in the literature review, this means that certain assumptions have to be made. It also determines which costing methods may be used. As was established in the literature review, three costing methods will be used in this paper: Analogous, Parametric and Engineering.

For the most part, as no upgrading plant using the BTF technology exists, the LCC will have to rely on the Analogous costing method. The first obvious analogy is to the experimental setup mentioned in the literature review section (Dupnock & Deshusses, 2017). This is the benchmark which a potential future plant will hope to reach. This is not a perfect analogy however, as this experiment was a small-scale proof of concept.

While no full-scale example of the BTF for biogas upgrading exists, the BTF technology has, as mentioned, been used for biogas sweetening, meaning H_2S removal. This is not a perfect analogy either, but in lack of better it can provide useful information. When the experimental setup fails to adequately describe operations and setup, details from biogas sweetening plants will be used as an analogy.

Between the two sources of information, the BTF alternative can be modelled. Nevertheless, the analysis of the system will have a great deal of uncertainty surrounding it, as is unavoidable at this stage in the process.

Two things need to be established in order to model the BTF alternative – what does the BTF consist of, and how does it operate.

The BTF alternative is assumed to consists of the same components and materials as a conventional BTF technology, with the additions that is required by its new purpose. First and foremost, this includes the addition of an electrolyser, to supply the necessary hydrogen – something that was not needed for a conventional BTF.

The Technology catalogue for renewable fuels includes three different types of electrolysis, of which the Alkaline Electrolyser appears to be the most viable in the year 2020, as it has the lowest reported investment costs and O&M costs. Meanwhile the Solid Oxide Electrolyser Cell is “not yet readily commercially available” and “To data only available at modest capacity level” (Energinet, 2019, s. 91), and the Low Temperature Proton Exchange Membrane Electrolyser Cell has an “uncertainty regarding the lifetime of the system” – which is unfortunate, as it also has a “High stack cost” (Energinet, 2019, s. 100).

If the results of Dupknock and Deshusses are to be replicated however, the Biotrickling filter cannot stand on its own. Dupknock and Deshusses estimates that a 90 % methane purity can be realistically achieved, which falls short of the legal requirements for BNG. Therefore, a second upgrading technology needs to be used, to remove the remaining $C0_2$. This second upgrading can be scaled in accordance with the remaining 10% CO_2, necessitating a much smaller plant[7].

This paper assumes that the secondary upgrading technology will be a chemical absorber[8]. The stripped CO_2 will then be led back into the BTF, so that it may be converted into CH_4.

The Methanogens will require minerals in order to survive. The original experiment used a specific mineral medium, and provided the method in which to create it, and the amount used. This method however does not appear feasible in a scaled-up case. The cost of the medium, estimated by summarizing the costs of its component as they appear on websites from various chemical providers, even ignoring the labor cost of maxing said components in the correct order, would exceed ten million DKK a year. This does not correspond with the cost of nutrients in scale up conventional BTF's (Deshusses & Webster, 2000, s. 1954). This paper does not assume that the same nutrients can be used – it merely assumes that the cost of minerals per cubic meter of gas is comparable between the BTF alternative and a conventional BTF. The aforementioned source provides three different figures for cost of minerals per m^3 of treated gas; one estimated cost and two actual costs, one lower end, one upper end (Deshusses & Webster, 2000, s. 1954). These figures will be used in the LCC model.

Furthermore, while BTF's are capable of removing hydrogen sulfide, this requires the presence of the proper microorganisms. If the technology is to be used for biogas upgrading, as specified by Dupknock and Deshusses, it will use hydrogenotrophic methanogens. This means that a secondary technology is needed for the biogas sweetening. As stated in the literature review section, a chemical absorber can remove H_2S along with the CO_2. In the case of the chemical absorber, the absorbed gasses will be led back into the BTF reactor, for further enrichment. As such, if the H_2S is not removed from the cycle, it will accumulate. Therefore, a H_2S removal technology will have to be added to the system. This will consist of a conventional BTF reactor, with the proper bacteria for H_2S removal. This is assumed to have a H_2S removal efficiency of 99.9 % (Cano, Colón, Ramírez, Lafuente, & Gabriel, 2018, s. 666).

As such, the BTF alternative will consist of the primary BTF upgrading reactor, the chemical absorber and the secondary BTF reactor for H_2S removal. The biogas will first be injected into the BTF, where it will be subjected to the hydrogen. This will enrich the biogas and achieve the 90 % methane purity. The biogas will then be injected into the chemical absorber, which will upgrade the biogas to natural gas quality. The remaining CO_2, alongside any H_2S, will be absorbed by the chemical solvent and, after the solvent has been regenerated at high temperature, be led through a conventional BTF. This takes care of the H_2S. The remaining CO_2 will be led back into the BTF, so that it may be enriched, rather than go to waste.

[7] The scaling of the chemical absorber was confirmed by supervisor Lars Yde in an email correspondence the 11th of March 2019

[8] This choice was made after consultance with supervisor Lars Yde, on the 13th of February 2019.

The literature suggests that manufacturers of upgrading technology often offers a maintenance service, at a yearly fee equal to a few percent of the original procurement cost. This paper will assume that the BTF technology will be manufactured by a third party, which will offer such a service. The percentage is assumed to be comparable to that of HPWS and Chemical absorber technologies, with a larger margin of error, to account for the uncertainty pertaining to a developing technology.

The BTF will require some heat, as the microorganisms need. This paper assumes that the heat needed will be provided by the electrolyser – the data catalogue shows that an electrolyser of the chosen variety (AEC) has a heat output equal to approximately 14 percent of its capacity (Energinet, 2019, p. 111). As the original experiment did not specify the heating requirements to keep the reactor at the required temperature, and because the even if it did, the data would likely not scale well to a full-sized reactor, this assumption has been made, to avoid having to construct a thermodynamic model of the reactor.

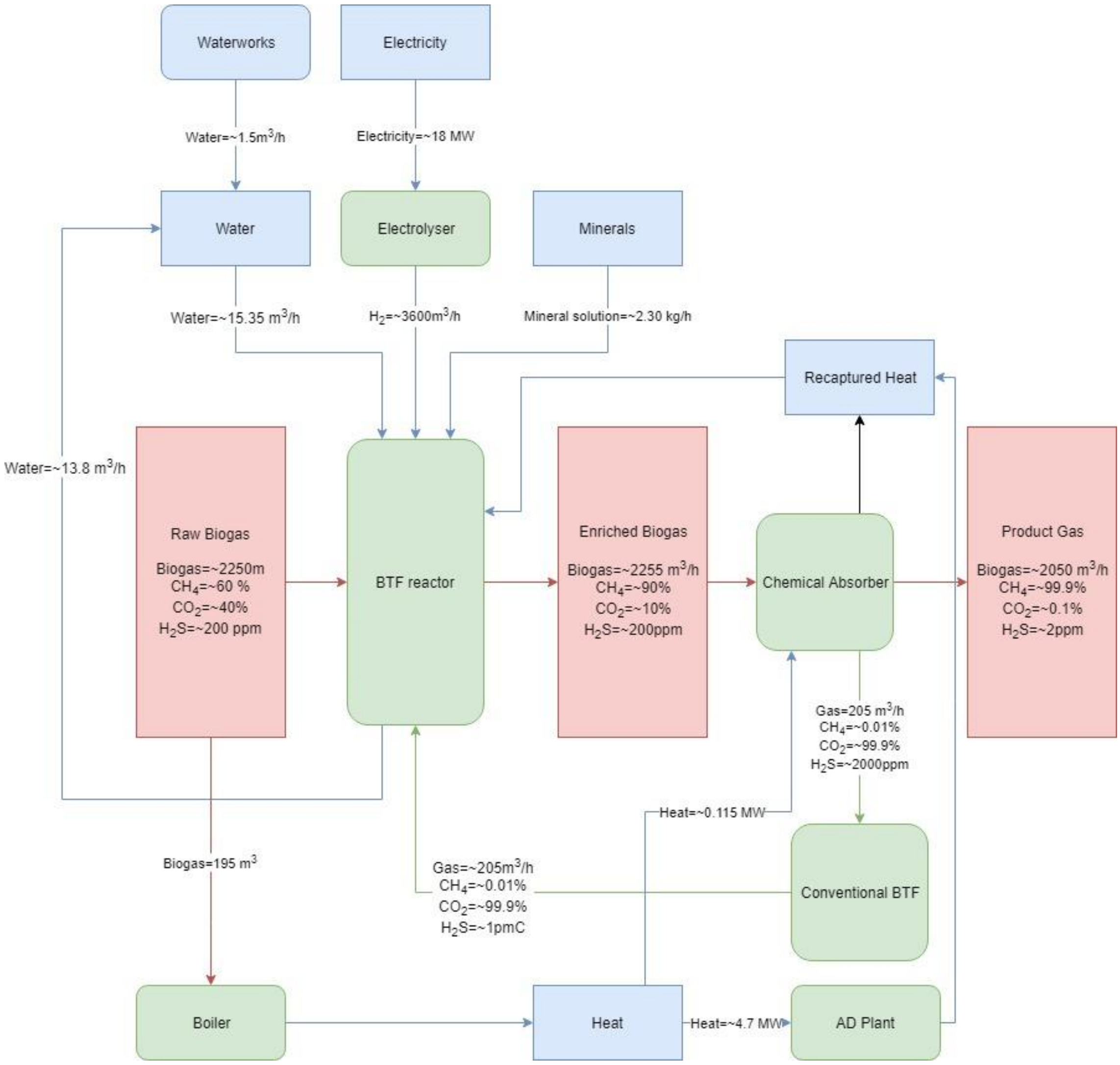

Figure 5 - Conceptual Schematic of the BTF Alternative - Red denotes flow of biogas, blue denotes other resource flow and green denotes internal production components

Table 3 - Table of assumptions, BTF alternative - if a single figure is portrayed in middle column, the factor is deterministic, if two are portrayed the distribution is uniform and if three are portrayed, distribution is triangular.

Factor	Lower	Most Likely	Upper
Methane yield – from substrates $\left[\frac{m^3}{year}\right]$ (deterministic)		11.843.078 (see equation Equation 31 - Definition of Yearly Base Methane Production)	
CO_2 content	30	39.7	50

$[\% \; of \; biogas]$ (triangular)			
Theoretical Methane yield of BTF $\left[\frac{m^3_{CH_4}}{year}\right]$ (triangular)	16918682	19640262	23686156
Technical Availability [%] (triangular)	94.3 (worst case scenario, if BTF and Chemical Absorber having 10 days of unplanned downtime a year) (Energinet, 2019, s. 34)	96 (comparative to chemical absorber)	100 (theoretical upper limit)
Methane Leakage [%] (triangular)	0 (Dupnock & Deshusses, 2017)		0.1 (Comparable with Chemical Absorber)
Methane Purity of BTF technology (deterministic)		90 % (Dupnock & Deshusses, 2017, s. 498)	
Methane Purity of chemical absorber (deterministic		99.9 %	
Overall CO_2 removal rate of BTF alternative (deterministic)		~99.9 %	

Heat Consumption $\left[\frac{kWh}{m^3_{CH_4}}\right]$ (triangular)	0.05 (based on 10% of Chemical Absorption)	0.055 (based on 10% of Chemical Absorption)	0.075 (based on 10% of Chemical Absorption)
Hydrogen Usage $\left[\frac{m^3_{H_2}}{m^3_{CH_4}}\right]$ (deterministic)		4 (see Equation 1 - Stoichiometry of Hydrogenotrophic Methnaogens)	
Electricity Usage, Electrolyser $\left[\frac{kWh}{kg_{H_2}}\right]$ (uniform)	51.23 (Energinet, 2019, s. 111)		59.67 (Energinet, 2019, s. 111)
Electricity Usage, pump, blower etc. $[kW]$ (uniform)	1.39 (see Appendix 5 – LCA inventory – BTF)		2.89 (see Appendix 5 – LCA inventory – BTF)
Usage of Mineral Medium $\left[\frac{kg_{medium}}{m^3_{inlet\ methane}}\right]$	3.41E-04 (Deshusses & Webster, 2000, s. 1954).	1.02E-03 (Deshusses & Webster, 2000, s. 1954).	2.45E-03 (Deshusses & Webster, 2000, s. 1954).
Water Usage $\left[\frac{m^3}{year}\right]$ (triangular)	107691.9 (see Appendix 5 – LCA inventory – BTF)	13277.088 (see Appendix 5 – LCA inventory – BTF)	161537.9 (see Appendix 5 – LCA inventory – BTF)
Technical Lifetime $[years]$ (deterministic)		20	

HPWS

HPWS works due to the fact that CO_2 is much more soluble in water that methane is. CO_2 is still not very soluble, just more so than CH_4. As such, the process is done under pressurized conditions, which increases the CO_2's solubility (Budzianowski, Wylock, & Marciniak, 2017)[9].

The technology modelled in this paper is divided into three towers, the Absorption Tower, the Flash Tower and the Desorption Tower, although examples with less does exist (Muñoz, Meier, Diaz, & Jeison, 2015). The water and the biogas are first lead into the Absorption Tower under pressure. The process can occur at 6-20 bars depending on the type of plant (Muñoz, Meier, Diaz, & Jeison, 2015, s. 6) – this pressurization represents the larger part of electricity consumption from this technology. There, the CO_2 is absorbed by the water, which is then led to the second tower, while the now upgraded biogas can be injected into the natural gas grid.

This second tower, the flash tower leads to the emittance of a CO_2 (80-90 %) and CH_4 (10-20 %) mixture, which is lead back into the absorption tower. This is to reduce the inevitable CH_4 losses that comes with this method. The water is then lead into the final tower, the desorption tower, where the water will be brought back to atmospheric pressure and the CO_2 will be removed from the water.

This method can remove H_2S simultaneously with the CO_2 – this can lead to maintenance issues, as dissolved H_2S is highly corrosive (Sun, et al., 2015, s. 524). As such, the H_2S is usually removed beforehand – however, this paper has modelled the AD plant after Nature Energy Midtfyn, which relies on their HPWS system for biogas sweetening (Henriksen, 2015, s. appendix, 3 a)[10]. As such, this paper assumes that the HPWS technology will remove the H_2S.

It is possible to regenerate the water, meaning that the CO_2will be removed, so that the water may be reused. In this paper, the water is assumed to be led back into the digestion tank, in accordance with operations at Nature Energy Midtfyn. Even if the water had been regenerated however, the CO_2 would usually not be collected anyways (Sun, et al., 2015, s. 524).

Due to the fact that CH_4 still is soluble in water, this technology does lead to a methane loss, at a few percent.

[9] Water scrubbers which operates under near atmospheric pressures does exists (Budzianowski, Wylock, & Marciniak, 2017, s. 4), but these will not be modelled in this paper.
[10] The source is a schematic of the opgrading technology, showing that inlet gas having approximately 200 ppm of H_2S and the outlet product gas having approximately 3.3 ppm.

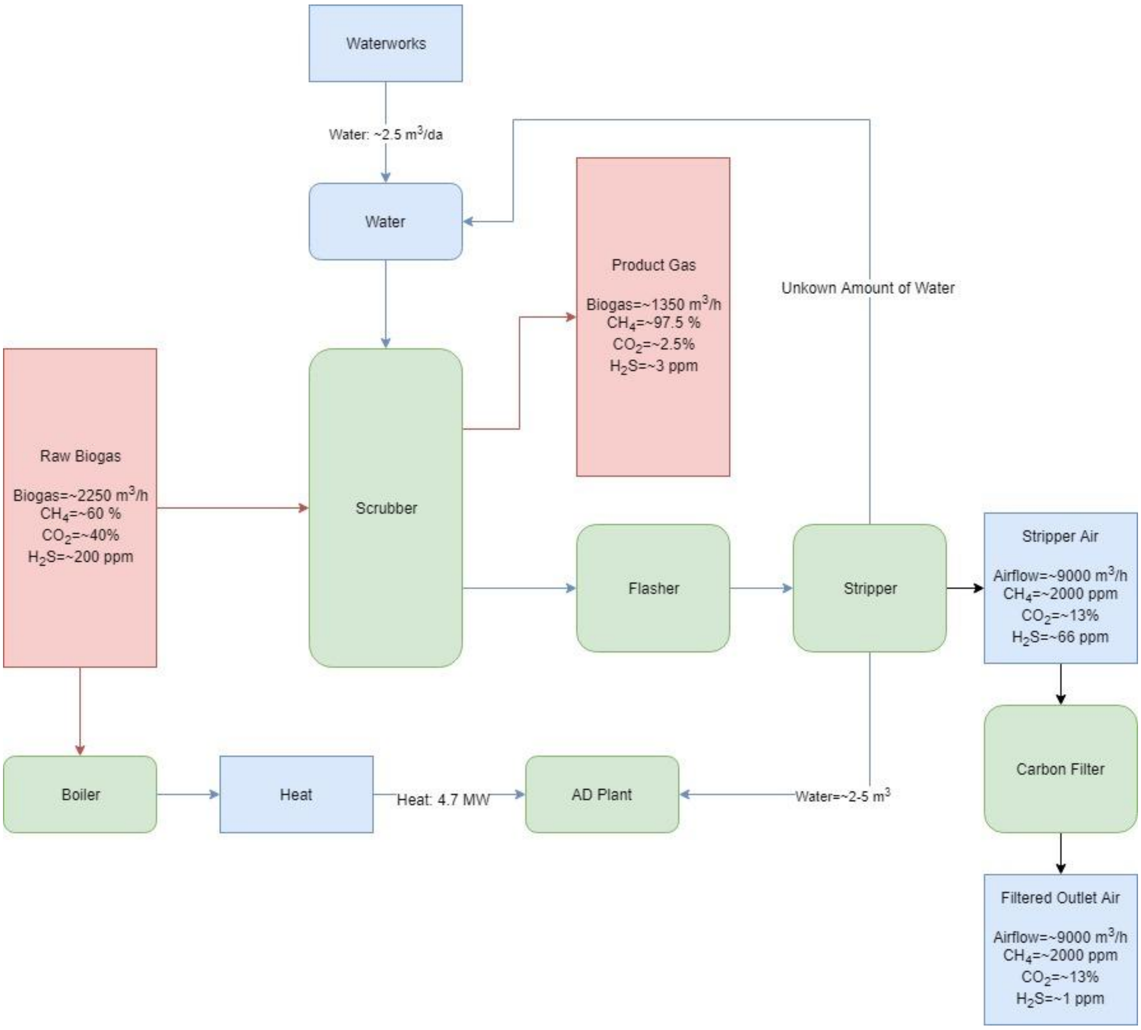

Figure 6 - Conceptual Schematic of the HPWS Alternative, modified from (Henriksen, 2015, s. appendix 3b) - Red denotes flow of biogas, blue denotes other resource flow and green denotes internal production components

Table 4 - Table of assumptions, HPWS alternative - if a single figure is portraid in middle column, the factor is deterministic, if two are portraied the distribution is uniform and if three are portraied, distribution is triangular

	Lower	Most Likely	Upper
Methane yield – from substrates $\left[\frac{m^3}{year}\right]$ (deterministic)		11.843.078 (see Equation 31 - Definition of Yearly Base Methane Production)	
Methane Leakage [%] (triangular)	1 (Hoyer, Hulteberg, Svensson, Josefina,	2 (Patterson, S., R., & Guwy, 2011, s. 1809)	4.7 (Patterson, S., R., & Guwy, 2011, s. 1809)

	& Nørrgård, 2016, s. 68)		
Technical Availability [%] (triangular)	96 (Patterson, S., R., & Guwy, 2011, s. 1810)	98 (Henriksen, 2015, s. appendix 1, p. 42)	100 (theoretical upper limit)
Heat Requirements (deterministic)		Non	
Water Usage $\left[\frac{m^3}{day}\right]$ (uniform)	2 (Henriksen, 2015, s. appendix 1, p. 14)		3 (Henriksen, 2015, s. appendix 1, p. 14)
Electricity Consumption $\left[\frac{kWh}{m^3}\right]$ (triangular)	0.17 (Hoyer, Hulteberg, Svensson, Josefina, & Nørrgård, 2016, s. 68)	0.22 (Pierre, et al., 2017, s. 285)	0.43 (Patterson, S., R., & Guwy, 2011, s. 1809)
Maintenance $\left[\frac{\%\ of PC}{year}\right]$ (uniform)	2 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 42)		3 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 42)
Technical Lifetime $[years]$ (deterministic)		20 (Energinet, 2019, s. 49)	

Chemical Absorption

The chemical absorber in theory works under the same principle as the HWPS, namely that CO_2 is more soluble than CH_4. The water has been exchanged a chemical solvent, most often amines, since these react selectively with CO_2 (Sun, et al., 2015, s. 524). The chemical absorber has a much lower methane loss than the water scrubber, at as little as 0.1 %, due to the low solubility of CH_4 in the amines (Muñoz, Meier, Diaz, & Jeison, 2015, s. 11).

The chemical absorber operates at lower pressures (1-2 bars) than a HPWS, which results in lower power requirements (Muñoz, Meier, Diaz, & Jeison, 2015, s. 11). The technology does needs heat however, in order to regenerate the solvent. As the chemical solvent is not as cheap or as environmentally harmless as water, this is preferable when compared to the alternative of only using the solvent once.

The chemical absorber works in much the same way as the HPWS – meaning that the solvent is led into the absorption or scrubber tower, where the CO^2 is absorbed by the solvent. The now upgraded biogas is led onto the point of injection into the natural gas grid, while the solvent is led to the desorption or stripper tower. Here the solvent is heated, which releases the CO_2, allowing for the reuse of the solvent, which is cycled back into the scrubber tower.

This heat will be supplied by the AD plant's boiler, which already supplies the AD plant with process heat.

As with the HPWS, the chemical absorber can handle the removal of H_2S. For some plants it is recommended that biogas sweetening occur beforehand, but others can handle it (Muñoz, Meier, Diaz, & Jeison, 2015, s. 11). This paper assumes that the Chemical Absorption alternative simultaneously remove CO_2 and H_2S from the biogas, and that both are removed from the solvent in the regeneration process.

Several different solvents are available – for the purpose of this paper, the Chemical Absorption alternative is assumed to use monoethanolamine.

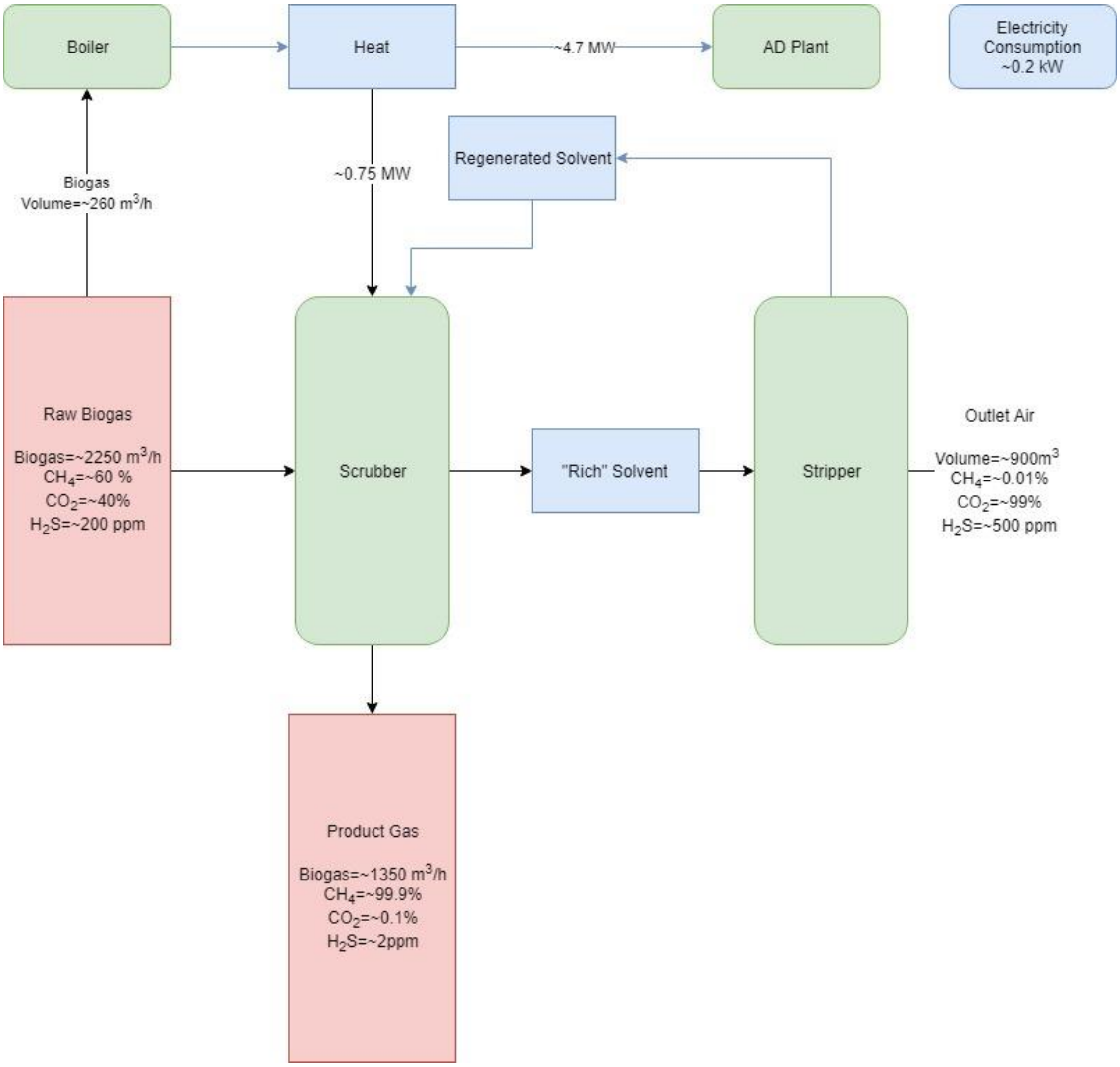

Figure 7 - Conceptual Schematic of the Chemical Absorption Alternative - Red denotes flow of biogas, blue denotes other resource flow and green denotes internal production components

Table 5- Table of assumptions, Chemical Absorption alternative - if a single figure is portraid in middle column, the factor is deterministic, if two are portraied the distribution is uniform and if three are portraied, distribution is triangular

Factor	Lower	Most Likely	Upper
Methane yield – from substrates $\left[\frac{m^3}{year}\right]$ (deterministic)		11.843.078 (see Equation 31 - Definition of Yearly Base Methane Production)	
Technical Availability	91	96	100

[%] (triangular)	(Patterson, S., R., & Guwy, 2011, s. 1810)	(Bauer, Hulteberg, Persson, & Tamm, 2013, s. 20)	(theoretical upper limit)
Heat consumption $\left[\frac{kwh}{m^3}\right]$ (triangular)	0.50 (Angelidaki, 2018, s. 454)	0.55 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 51)	0.75 (Angelidaki, 2018, s. 454)
Electricity $\left[\frac{kwh}{m3}\right]$ (triangular)	0.12 (Patterson, S., R., & Guwy, 2011, s. 1809)	0.15 (Patterson, S., R., & Guwy, 2011, s. 1809)	0.646 (Patterson, S., R., & Guwy, 2011, s. 1809)
Methane Loss [%] (triangular)	0.03 (Patterson, S., R., & Guwy, 2011, s. 1809)	0.04 (Pierre, et al., 2017, s. 285)	0.1 (Angelidaki, 2018, s. 454)
Water consumption $\left[\frac{m^3_{water}}{m^3_{CH_4}}\right]$ (deterministic)		0.3 E-5 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 51)	
Solvent Consumption $\left[\frac{m^3_{solvent}}{m^3_{CH_4}}\right]$ (determininstic)		0.3 E-5 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 51)	
Maintenance $\left[\frac{\%\,of PC}{yearly}\right]$ (uniform)	2.5 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 40)		3.5 (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 40)
Technical Lifetime $[years]$		20 (Energinet, 2019, s. 49)	

(deterministic)

Work Breakdown Structure

The work breakdown structure is the 3rd of the 8 parts if the LCC

A Work Breakdown Structure or Cost Breakdown Structure can be used to assist the cost estimation. It works by breaking down a project into its cost incurring component. The intent is to ensure that all relevant components and parts are considered and included in the cost estimation. It can be structured in different ways, but for the purpose of an LCC, the most intuitive would be chronologically.

The WBS is not a cost estimating method in itself but is merely a tool to gain an overview of the costs and when they are incurred.

Table 6 - Work Breakdown Structure of the 3 alternatives and the AD plant, divided into phases

	BTF	HPWS	Chem Ab	AD
Conceptualisation	n/a	n/a	n/a	n/a
R&D	n/a	n/a	n/a	n/a
Procurement	Gas inlet fan	Technology sold and cost estimated as a single whole	Technology sold and cost estimated as a single whole	Land Purchase (78,464 m^2)
	Water Pump	Natural gas connection station	Natural gas connection station	Trucks (6)
	Reactor tank	Compressor	Compressor	Reception hall (360 m^2)
	Packing Material	Natural gas connection pipeline	Natural gas connection pipeline	Hall for solid biomass (720 m^2)
	Blower (hydrogen)			Personel Building (165 m^2)
	Piping			Technical Building (200 m^2)

	Chemical Absorber			Silo for energy crops (25,000 m^3, "*plansilo*")
	Convetional BTF			Boiler (2.5 MW)
	Electrolyser			Heat Exchangers
	Heat Exchanger			1^{st} Reception tank (700 m^3)
	Natural gas connection station			2^{nd} Reception tank (3000 m^3)
	Compressor			Sanitation tanks (2 a 20 m^3)
	Natural gas connection pipeline			Mixing tank (160 m^3)
				AD Tanks (3 a 8500 m^3)
				Gas storage/digestate tank (3000 m^3)
				Piping (2486.7 m)
				Torch
				VVS and electrical connections
				Installation Cost
Operation	Mineral Medium	Water	Water	Slurry, cow manure

	Electricity (electrolysis)	Electricity	Chemical Solvent	Slurry, pig manure
	Electricity (water pump)	Maintenance	Electricity	Straw
	Water		Maintenance	Maize
	Maintenance			Labor (6 fulltime laborers)
				Electricity
				Insurance and administration
				Maintenance
Retirement	Resale	Resale	Resale	Resale

LCC

Assumptions

Now that each relevant cost incurring component has been listed, it is time for the 4th of 8 parts of the LCC: defining how each cost incurring component is to be estimated.

The performance of the plant will be assumed to be the same over the course of its lifetime. The model will therefore not consider any decline in production that might occur as a consequence of deteriorating equipment, nor any increase as a consequence of any technological advancements. The model will take into consideration the cost and forced downtime that comes with maintenance, however.

As stated in the literature review section, the model will consider the legal framework which is deemed to be relevant for the construction and operation of the biogas plant, but it will not consider any possible future changes to said framework, in any capacity other than the ones specified by the scenarios. The only exception to this will be the law limiting the amount of energy crops that may be used by a biogas producer – even though the law is supposed to become inactive in the year 2020, there is every reason to expect that the limitation will continue beyond this point. As such, this model will assume that it, or a similar law, will be in place for the duration of the investment.

The model will assume that the plant will incorporate a biogas fueled boiler, which will provide all process heat needed by production, be it in the AD or upgrading part of the process. This boiler will be powered by the upgraded biogas, produced on site. The amount of heat will differ between scenarios, and will reduce the output, and therefore also monetary income of the plant.

The location of Funen was chosen to give insight into the composition of the biomass. The water prices were also estimate based on local water works. The choice in location will not influence any other factor, such as cost of property procurement, power, labor costs, etc. These will instead be based on national figures as specified.

NPV

The result of the LCC will be presented as a Net Present Value analysis. This is in order to compare the results across alternatives, as they produce different amount of BNG. A simple comparison between the sum of their costs would therefore be inadequate. A comparison of accumulated costs per m^3 or GJ would not suffice either, as this would ignore the Time Value of Money – the concept that the value of incoming and outgoing cash flows changes with time.

An NPV analysis is a method of assessing the worth of investment, by discounting incoming and outgoing cash flows into a present value. The present value in this paper will be DKK in the year 2019.

As can be seen from Equation 2 the value of an incoming cash flow becomes smaller, the longer an investor has to wait for it. An income today is more valuable than ten years from now, as that money could be invested in the intervening years. For the same reason, expenses are preferably paid later. The NPV analysis reflects accounts for this (Kenton, Net Present Value (NPV), 2019), and is therefore a useful method of assessing the financial viability of an investment. If the total NPV is non negative, the investment is worthwhile, if it is negative it is not. When comparing multiple alternative, as is the case in the paper, the investment with the higher NPV is the strongest.

The NPV is defined as

Equation 2 – Definition of NPV

$$NPV = \sum_{t=1}^{T} \frac{Profit_t}{(1 + CoE)^t}$$

Where T is the lifetime of the project [years], t is the relevant year [-] and CoE is the Cost of Equity [-].

The CoE is the return on investment that is expected (Kenton, Cost of Equity, 2019). The CoE varies from investor to investor, as some will expect a greater return than other. In this paper it will be defined in accordance with the Capital Asset Pricing Model (Madsen & Hartzberg, 2019, s. 2):

Equation 3 – Definition of CoE

$$CoE = RFIR + (MRP * \beta_E)$$

Where RFIR is the Risk-Free Interest Rate [-], meaning the interest rate that one would expect from an investment with no risk at all. In this paper it is equal to the long-term interest rate (see the Scenarios section). MRP is the Market Risk Premium [-], the difference between RFIR and the return of investment that is expected from a non-zero risk investment. In this paper, the MRP is set to 0.061, which is the most recent average for the Danish market, that the writer of this paper is aware of (Wrang, 2019). β_E is Beta Equity, an indication of a given investor's proclivity to risk. If an investor is aligned with the rest of the market, β_E has a value of 1, which is also what this paper will assume (Madsen & Hartzberg, 2019).

Taxes and Depreciation

Historically, the corporate tax has changed over time in Denmark, and it is likely that it would change over the course of the 20 years that a biogas plant would operate. This paper, however, assumes a static corporate tax of 22 %, in accordance with the 2019 level (Skatteministeriet, 2019, s. § 2, stk 3). This means that 22 % of all profits are paid as taxes and are subtracted from the NPV before discounting.

Depreciation is the amount with which physical assets are reduced in value. For example, in the case of a Biogas Plant, there is a difference between the procurement costs, and the resale value after 20 years of operations. This Depreciation can be considered a form of expense, and can subtracted from the profit of the plant, thereby reducing the corporate that need to be paid (SOURCE). This paper will use linear depreciation, meaning that the yearly depreciation will be equal to the difference in procurement costs and resale price, divided by the lifetime of the investment:

Equation 4 - Definition of Linear Depreciation

$$DPR_{a,t} = \frac{PC_a - RV_a}{T}$$

Wheres DPR_t is the depreciation in the year t [DKK], PC_a is the procurement cost of the alternative [DKK] and RV is the resale value [DKK]. As the depreciation is linear, the amount remains the same each year. The components that are subject for depreciation are "machines, inventory and other means of operation" that is used in a corporate setting and which loses value as they are used (Danish Ministry of Taxation, 2019, s. § 2-3). For the purpose of this paper, it means all procurement costs except the purchase of land which is not expected to lose its value as part of its use.

Table 7 - Table of assumptions, AD plant - if a single figure is portrayed in middle column, the factor is deterministic, if two are portrayed the distribution is uniform and if three are portrayed, distribution is triangular

Factor	Lower	Most Likely	Upper
Biomass intake		360.000	
Technical Lifetime		20	

(deterministic)		(Energinet, 2019, s. 34)	
Construction time (deterministic)		1 (Energinet, 2019, s. 34)	
Years Active		2021-2040	
Heat Consumption $[\% \; of \; methane \; production]$	7.2 (Energinet, 2019, s. 34)	8.9 (Energinet, 2019, s. 34)	12 (Energinet, 2019, s. 34)
Electricity Consumption $\left[\frac{kWh}{ton \; substrate}\right]$ (triangular)	16 (Energinet, 2019, s. 34)	18.6 (Energinet, 2019, s. 34)	25 (Energinet, 2019, s. 34)
Maintenance $\left[\frac{\% \; of PC}{year}\right]$	2	3	4

The cost incurring elements can, as mentioned previously, roughly be divided into the Procurement, Operational and Retirement phases, as the Conceptualization and R&D phases are not relevant for this paper.

These costs will in turn be divided into four: one for each of the three alternatives, and one final for the AD Plant. The reason for this is, that the investment of an upgrading plant, as discussed in the literature section, in Denmark is inherently tied to the investment of an AD plant. The three alternatives therefore all have the AD costs in common.

As established in the literature review section, there are many different methods of estimating costs in an LCC. The methods that are useful determined by the data maturity, and this in turn is determined by which phases has already occurred. As the alternatives have different levels of data maturity, different methods will be used.

Procurement Phase

The BTF alternative is currently in development, meaning that it is not possible to rely on historical data. Instead this paper will rely on the fact that BTF technology has already been used for other purposes, for example removal of hydrogen sulfide from biogas. This paper will assume that the BTF alternative is sufficiently analogous to its hydrogen sulfide usage that their constructions are similar. The paper will then Engineering method to estimate the costs.

For the HPWS and the Chemical Absorption alternatives, plenty of data already exists on the subject – so much so, that it is possible to use the Parametric method to estimate the costs. This has already been done by several different papers, as was discussed in the literature section. Their findings do not differ enough to justify retreading their work, so for the Procurement costs at least, this paper will rely on that Parametric method.

For the AD plant, data does exist that would allow for a Parametric cost estimation (Energinet, 2019, s. 34). There are three reasons however, why the Engineering method has been used instead. Firstly, the data also shows that significant cost variations can occur. Secondly, much of the work necessary for the engineering method will be necessary to perform the LCA as well. Finally, and more importantly, the estimation of the Operational Costs will depend directly on the component used in the Procurement – as such the Engineering method will be used.

All three alternatives will also need a connection to the natural gas grid. The connection is assumed to consist of a pipeline connecting the plant to the network, and a station containing the compressors, monitoring equipment and the like. This has been estimated using the parametric method, using data from business cases and project description for biogas plants in Denmark and the Technology Catalogue for energy transport (Energinet, 2017, p. 63) respectively.

The station is estimated as a “type 2” station using a triangular distribution with the 2020 data, with the addition of a compressor worth 10 million. The pipeline itself is estimated using the data from Danish biogas plants project descriptions (Dansk Gas Distribution A/S, 2018, pp. 4-5) (SEGES, 2017, p. 21). The maintenance of stations and gas connection are both modelled in accordance with the Technology Catalogue.

Financing

As the majority of the procurement costs are to be paid in full in year one, it can be outside the realm of possibility for many investors to finance the costs on their own all at once. As such, this paper assumes that the investor will have to borrow half of the procurement costs, as a ten-year loan at a 4-5 % interest rate – with the interest rate being determined by the scenario.

This means an additional expense that will be paid over the first ten years of the operational phase. For the purpose of this paper, it will still be considered part of the procurement costs:

The financing costs will be equal to

Equation 5 - Definition of Financing Costs

$$FC_{a,s} = \sum_{t=1}^{10} \left(\frac{PC_a}{2} * \frac{LIR_s * (1 - COR)}{1 - (1 + IR * (1 - COR)^{-10}} \right) / (1 + COE^t)$$

Where $FC_{a,s}$ is the financing costs for the respective scenarios and alternatives [DKK], LIR_s is the lending interest rate in the scenario s $[-]$ and COR is the corporate tax rate $[-]$.

In total, the Procurement costs will be equal to the Financing costs, as well as the acquisition costs of the AD plant, the upgrading technology and the connection to the natural gas network

Equation 6 - Definition of Procurement Costs

$$PC_a = PC_{Ad} + PC_{Up,a} + PC_{Connection} + FC_a$$

Where PC_{ad} is the procurement cost of the ad plant [DKK], $PC_{up,a}$is the procurement cost of the upgrading technology alternatives [DKK] and $PC_{connection,a}$ is the procurement cost of the natural gas connection for the alternatives [DKK][11].

Table 8 - Table of Financial Assumptions - Common for all alternatives

Subsidy, part 1	82.2 DKK/GJ in the year 2019, regulated after yearly inflation
Subsidy, part 2	26 DKK/GJ, regulated based on natural gas price
Financing	Half
Deprecation	Linear
Corporate Tax Rate	22 % of profits

Operational Phase

The operational costs consist of many different elements, as it includes any expenses that are expected to be paid during the project's operational life, which in this case is 20 years.

BTF

As described in the Alternatives section, the BTF alternative needs power to run, both for the electrolysis that supply the hydrogen and the pumps and fans that keep production going. Furthermore, it needs water, and a mineral medium to the microorganisms that supply the methaginisation.

The electricity is twofold, first the electrolysis and then everything else. First is the electricity from the electrolysis:

[11] The natural gas connection cost changes in accordance with the amount of gas that needs to be connected, and as the gas is different between the alternatives, so is the cost.

Equation 7 - Definition of Electrolysis Power Costs, BTF

$$EC_{BTF,e,s,t} = EP_{s,t} * EU_{BTF,e} * \rho_{H_2} * H_2 2CO_2 * CO_2 C_{tri} * M_{PB,BTF}$$

Where $EC_{BTF,e,s,t}$ is the electricity cost for BTF alternative, for the electrolysis e in the scenario s in the year t [DKK], $EP_{s,t}$ is the electricity price in the scenario s and year t $\left[\frac{DKK}{kWh}\right]$, $EU_{BTF,e}$ is the electricity consumption of the BTF alternative's electrolyser $\left[\frac{kWh}{kg_{H_2}}\right]$, ρ_{H_2} is the density of hydrogen $\left[\frac{kg_{H2}}{m^3_{H_2}}\right]$, $H_2 2CO_2$ is the relationship between hydrogen and CO_2 needed for the BTF technology $\left[\frac{m^3_{H_2}}{m^3_{CO_2}}\right]$, $CO_2 C_{tri}$ is the CO_2 content in the un-upgraded biogas as a triangular distribution $\left[\frac{m^3_{CO_2}}{m^3_{CH_4}}\right]$ and $M_{PB,BTF}$ is the methane yield, "post boiler" for the BTF alternative $[m^3_{CH_4}]$.

The rest of the electricity consists of pumps to circulate the water and mineral medium and blowers to drive the gasses.

Equation 8 - Definition of Assorted Power Costs, BTF

$$EC_{BTF,a,t} = EP_{s,t} * EU_{BTF,a}$$

Where $EC_{BTF,a,t}$ is the electricity cost for the BTF alternative for the assorted components in the year t $[DKK]$, and $EU_{BTF,a}$ is the electricity usage for the BTF alternative for the assorted components $[kWh]$.

The water costs are decided by the water amount used and the water price. The water amount is determined to be equal to that of a conventional BTF of the same size, which is 1.1-1.7 times the minimum of 20 gallons h^{-1} per square foot of reactor cross sectional area (Oliver & Gooch, 2016, s. 1). The water price has been determined by examining the water prices of all water works on Funen in 2018-2019[12], then making a normal distribution from said data. The water works in Denmark differentiate their prices between a Fresh water price and a wastewater price. In this paper, only the Fresh water price is considered, as the water is assumed to not be led into the wastewater system, in accordance with the description of the alternatives.

The water price is then assumed to be subject to a yearly price increase equal to the CPI:

Equation 9 - Definition of Water Costs, BTF

$$WC_{BTF,t} = WU_{BTF} * (WP_{norm} * (1 + CPI_s)^{t-2019})$$

$WC_{BTF,t}$ is Water Cost for the BTF alternative in the year t $[DKK]$, WU is water use $[m^3]$, WP_n is water price as a normal distribution $\left[\frac{DKK}{m^3}\right]$ and CPI is Consumer Price index $[-]$.

[12] 2019 data was used unless it was not available, in which case 2018 was used instead.

The cost of the mineral medium has been estimated by summarizing the costs of its components. The medium itself is assumed to be identical with the one used in the experiment by Dupnock and Deshusses (Dupnock & Deshusses, 2017). Two different prices for each chemical component has been found from leading chemical suppliers and a uniform distribution has been made. For some of the components, only one supplier could be found, in which case the cost was made deterministic.

The amount of mineral medium consumed by the process is also assumed to be analogous to that of the original experiment. The original experiment consumed 2.5 ml Day^{-1} and removed 5 ml of CO_2 min^{-1}, meaning that the medium consumption in the full scale can be calculated based on the methane content of the substrates and the CO_2 content of the biogas

The prices are assumed to be the subject of inflation.

Equation 10 - Cost of Mineral Medium Consumption, BTF

$$MMC_{BTF} = M_{pb,BTF} * MMU_{BTF,tri*}(PMM * (1 + CPI_s)^{t-2019})$$

With MMC_{BTF} is the cost of the mineral medium for the BTF alternative $[DKK]$, $MMU_{BTF,tri}$ is the mineral medium usage for the BTF alternative as a triangular distribution $[\frac{kg}{m^3}]$ and PMM_{tri} is the price of the mineral medium $\left[\frac{DKK}{kg}\right]$.

As stated earlier (see the BTF section) literature indicates, that for upgrading technology in Scandinavia, it is common that the provider offers a maintenance service, equal to a percentage of the original price of the plant (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 20, 42 & 49).

The maintenance costs are assumed to be primarily due to periodic replacement of various components – price increases are therefore due to inflation, rather than increase in labor costs:

Equation 11 - Definition of Maintenance Costs, BTF

$$MC_{BTF,t} = PC_{BTF} * MP_{BTF}\ [-] * (1 + CPI_s)^{t-2019}$$

Where $MC_{BTF,t}$ is the Maintenance cost for the scenario s, in the year t $[DKK]$ and MP_a is the cost of the maintenance service for the alternative $[\%]$.

To summarize, the operational cost are the sum of each cost incurring element during the operational phase:

Equation 12 - Definition of Total Yearly Operational Costs, BTF

$$OC_{BTF,t} = EC_{BTF,e,t} + EC_{BTF,a,t} + MMC_{BTF,t} + WC_{BTF,t} + MC_{BTF,t}$$

Where OC_{BTF} is the operational costs of the BTF alternative $[DKK]$

HPWS

The HPWS alternative needs water as a solvent and electricity to pressurize the water.

The water cost, as in the case of the BTF alternative, is determined by the water consumption and the water price. The water price is determined the exact same way, but the water consumption is different and set as a normal distribution between 2 and 3 m^3 per day:

Equation 13 - Definition of Water Costs, HPWS

$$WC_{HPWS,t} = WU_{HPWS} * (WP_n * (1 + CPI_s)^{2019-t})$$

Where $WU_{HPWS,uni}$ is the water usage for the HPWS alternative $\left[\frac{m^3_{water}}{year}\right]$.

The electricity in turn is determined by the electricity price in DKK/kwh and the electricity consumption in kwh per m^3 upgraded biogas. The electricity prices are determined by the different scenarios. The electricity consumption is determined by a triangular distribution, based on sources found during the literature investigation:

Equation 14 - Definition of Electricity Costs, HPWS

$$EC_{HPWS,t} = EP_{s,t} * EU_{HPWS} * M_{pb,HPWS}$$

Where $EC_{HPWS,t}$is the cost of electricity for the HPWS alternative in the year t $[DKK]$, EU_{HPWS} is the electricity consumption for the HPWS alternative $\left[\frac{kWh}{m^3}\right]$ and $M_{pb,HPWS}$ is the methane that is available after the boiler $[m^3]$.

The maintenance costs, as in the case of the BTF alternative, is determined as a yearly cost equal to a fraction of the procurement costs.

Equation 15 - Definition of Maintenance Costs, HPWS

$$MC_{HPWS,t} = PC_{HPWS}[DKK] * MP_{HPWS,tri}\,[-] * (1 + CPI_s)^{t-2019}$$

The total cost of the operational phase is the sum of each cost incurring element in the operational phase

Equation 16 - Definition of total yearly Operational Costs, HPWS

$$OC_{HPWS,t} = EC_{HPWS,t} + WC_{HPWS,t} + MC_{HPWS,t}$$

Chemical Absorption

The Chemical Absorber needs a combination of water and amine as a solvent, electricity to pressurize the solvent and yearly maintenance.

Both the water and amine are being regenerated in the Chemical Absorption alternative, allowing for its reuse. Despite this, a small amount can be expected to be lost in operation, hence the need for new solvent to be periodically added. The cost of this is dependent on the amount being lost and its cost. The price of the chemical monoethanolamine is assumed to be increase in accordance with the CPI.

Equation 17 - Definition of Chemical Costs, Chemical Absorption

$$CC_{ChemAb,t} = CU_{ChemAb} * (CP_{Chemab} * (1 + CPI_s)^{t-2019})$$

Where $CC_{ChemAb,t}$ is the cost of chemicals for the Chemical absorber alternative in the year t $[DKK]$, CU_{ChemAb} is the chemical usage in a year $[m^3]$ and CP_{Chemab} is the price of the chemicals $\left[\frac{DKK}{m3}\right]$

The cost of water usage is calculated the same way as for the HPWS alternative (see Equation 13)

Equation 18 - Definition of Water Costs, Chemical Absorption

$$WC_{ChemAb,t} = WU_{ChemAb} * (WP_n * (1 + CPI_s)^{t-2019})$$

The electricity cost is calculated in the same way as in the HPWS alternative (see Equation 14)

Equation 19 - Definition of Electricity Costs, Chemical Absorption

$$EC_{ChemAb,t} = EP_{s,t} * EU_{ChemAb} * M_{ChemAb,pb}$$

The maintenance cost is calculated the same way as the HPWs alternative (see Equation 15).

Equation 20 - Definition of Maintenance Costs, Chemical Absorption

$$MC_{ChemAb,t} = AC_{ChemAb}[DKK] * MP_{ChemAb,tri}\ [-] * (1 + CPI_s)^{2019-t}$$

As was the case for the BTF and HPWS alternative, the yearly cost for the Chemical absorption alternative is the sum of each cost incurring component

Equation 21 - Definition of total yearly Operational Costs, Chemical Absorption

$$OC_{ChemAb,t} = EC_{ChemAb,t} + CC_{ChemAb,t} + WC_{ChemAb,t} + MC_{ChemAb,t}$$

AD Plant

The AD plant, which all alternatives have in common, need labor to run the plant, administrative costs such as insurance, the cost of buying and transporting the substrates and electricity costs.

The labor costs are determined by assessing how many full-time employments are needed for the plant, then assessing cost per full time employment. The cost per employment is a normal distribution based on yearly reports from the AD plants operated by the Funen based company

Nature Energy. The cost of employment is in this paper assumed to increase in accordance with the increase in GDP[13]. The AD plant is assumed to employ 6 full time posts – that are not tied to the transportation of substrates and digestates – in accordance with description from similarly sized plants (Nature Energy, 2019).

Equation 22 - Definition of Labor Costs, AD

$$LC_{AD,t} = NW_{AD} * W_{norm} * (1 + BNP_s)^{t-2019}$$

Here $LC_{AD,t}$ is the Labor Cost for the AD plant in the year t $[DKK]$, W_{norm} is the yearly wages per post as a normal distribution $\left[\frac{DKK}{year\ employment}\right]$ and NW_{AD} is the number of fulltime workers employed at the AD plant $[year\ employment]$.

Administrative costs cover insurances office administration, such as secretarial work and board related activities. This is subject to inflation (for the insurance) and BNP increases (for the labor related office work).

Equation 23 - Definition of Administrative Costs, AD

$$AdminC_{ad,t} = Ins_{ad} * (1 + CPI_s)^{t-2019} + OC_{ad,t} * (1 + BNP_s)^{t-2019}$$

Where $AdminC_{ad,t}$ is the administrative costs $[DKK]$, Ins_{ad} is the insurance cost $[DKK]$ and $OC_{ad,t}$ is the office cost $[DKK]$

The substrate costs are dependent on the amount of substrate, the type of substrates used and the price for each type of substrate. This paper assumes that four types of substrates are used: Pig manure, Cow manure, energy maize and straw. The reasons for this, and the fraction of each substrate used is described in the Substrates section.

The prices used include both the price of acquisition, as well as expenses accrued due to transportation, such as fuel, maintenance for the trucks and employment of the drivers. The prices are assumed to the be subject to inflation:

Equation 24 - Definition of Substrate Costs, AD

$$\begin{aligned} SC_{AD,t} = \big(&YSU * SF_{manure,pig} * SP_{manure} + YSU * SF_{manure,cow} * SP_{manure} + YSU \\ &* SF_{straw} * SP_{straw} + YSU * SF_{maize} * SP_{maize}\big) * (1 + CPI_s)^{t-2019} \end{aligned}$$

Here $SC_{AD,t}$ is Cost of substrates used by the AD plant in the year t $[DKK]$, YSU is the yearly substrate usage $[ton]$, $SF_{substrate}$ is the percentage of total substrate use that is represented

[13] This assumption is false, as wages are interely separate from BNP. The two often do not follow each other, as can be seen in an analysis from the Danish Nationalbank from March 2018 (Danmarks Nationalbank, 2018). However for the purpose of this paper, the assumption is deemed to be serviceable.

by each of the four substrates [%] and $SP_{substrate}$ are the prices of the respective substrates $\left[\frac{DKK}{ton}\right]$.

Electricity costs are determined by the electricity prices, determined by the scenarios, and the electricity consumption.

Equation 25 - Definition of Electricity Costs, AD

$$EC_{AD,t} = EP_{s,t} * EU_{AD} * YSU[ton]$$

Here EU_{AD} is the electricity consumption for the AD plant $\left[\frac{kWh}{ton}\right]$.

As always, the yearly operational costs is equal to the sum of the costs.

Equation 26 - Definition of total yearly Operational Costs, HPWS

$$OC_{ChemAb,t} = LC_{AD,t} + AdminC_{ad,t} + SC_{AD,t} + EC_{AD,t}$$

Substrates

In order to produce biogas, a substrate is needed. This can be slurry from cows and pigs, it can be straw or even energy crops to a limited extent. Common for all of these are, that they need to be transported from their place of origin to the biogas plant. The cost of said transport is dependent on the distance traveled - especially so for slurry, as it need to be transported twice[14] (Birkmose, Stefanek, Hjort-Gregersen, & Pedersen, 2014, s. 23). In order to minimize costs, the substrate being used should be restricted to that which is available in the area near the plant. This section will not discuss the costs associated with transport, but rather which substrates are available and where they are available.

This paper assumes the perspective of a Danish investor, investigating the possibility of investing in a biogas plant on the isle of Funen. In 2014 the Danish company Agrotech published a report detailing the potential for biogas production on Funen (Birkmose, Potentialet for nye biogasanlægpå Fyn, Langeland og Ærø, 2015). Using that report enables an estimate of the composition of substrates that a prospective plant may use.

This paper will focus on four types of substrate – pig slurry, cattle slurry, energy crops and straw. This choice is based on the abundance of the two former and the high energy density of the two latter.

The afrorementioned report specifies that on Funen, 2.361 thousand tons of slurry is being produced each year, of which 619 are from cattle and 1.701 are from swine[15]. If a biogas plant will receive its substrate from cattle and pig farms exclusively, it is possible to determine how much of the slurry can be expected to come from pigs and how much from cattle

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[14] Once as slurry to the biogas plant, and once as digestate to the relevant farms

[15] The remainder are primarily from poultry (2 thousand tons) and “furry animals” (*“pelsdyr”*)(40 thousand tons).

$$SCR = \frac{SP_{cows}}{SP_{cows} + SP_{pigs}} = \frac{619}{1701 + 619} = 0.26$$

Where SCR is the ratio of slurry stemming from cattle $[-]$ and SP is the slurry production on Funen $\left[\frac{ton}{year}\right]$

The report also determines that slurry remains the cheapest substrate in transportation costs up until the distances reaches +30 kilometers, after which straw becomes competitive. Due to the abundance of slurry on Funen, transportation above 30 kilometers does not seem likely. As such, straw on its own will not be considered in this paper. However, straw mixed up with animal slurry will be considered, as biogas produced on slurry alone is not financially viable, due to slurries low dry matter percentage and energy density (Birkmose, Potentialet for nye biogasanlægpå Fyn, Langeland og Ærø, 2015, s. 6).

In order to raise the energy density, it will be assumed that 8 percent of the slurry mixture will be straw, added to the slurry in order to raise the dry matter percentage to 14. Experience shows that most biogas plants have trouble handling a dry matter percentage higher than that (Birkmose, Potentialet for nye biogasanlægpå Fyn, Langeland og Ærø, 2015, s. 6).

In the literature section, the laws specifying that sustainable biogas cannot be produced from any substantial amount of energy crops, a trend which historically appears to be increasing. This paper assumes that 5.5 % of the substrates used will be energy maize, equaling the percentage projected by Nature Energy Midtfyn (Henriksen, 2015, s. 11)[16]. The remainder will be manure, mixed in with the straw, in accordance with fractions named in this section – being that 8 percent of the nonmaize part will be straw, 26 percent of the manure part will be from cows, and the remaining part will be manure from pigs:

Equation 27 - Definition of the Substrate fraction, maize

$$SF_{maize} = 0.055$$

Equation 28 - Definition of the Substrate fraction, straw

$$SF_{straw} = (1 - SF_{maize}) * 0.08 = 0.0756$$

Equation 29 - Definition of the Substrate fraction, manure, cow

$$SF_{manure,cow} = (1 - SF_{maize} - SF_{straw}) * 0.26 = 0.226044$$

Equation 30 - Definition of the Substrate fraction, manure, pig

$$SF_{manure,pig} = 1 - SF_{maize} - SF_{straw} - SF_{manure,cow} = 0.643356$$

[16] The source states that 20.000 tons out of 360.000 tons yearly will be maize, equaling 5.5 percent.

Income

Common for all alternatives is that they provide an income via the sale of BNG. The income is determined by the natural gas price, the subsidies ensured by the Danish government and the amount of bio natural gas produced. This amount varies between the alternatives and is further reliant on the technical availability and methane leakage that the alternatives statistically experience.

The amount of biogas available for sale is dependent on the methane – this is in turn dependent on the substrates used, and the methane content of each of them:

Equation 31 - Definition of Yearly Base Methane Production

$$M_{AD,t} = \left(YSU * SF_{manure,pig} * MC_{manure} + YSU * SF_{manure,cow} * MC_{manure} + YSU * SF_{straw} * MC_{straw} + YSU * SF_{maize} * MC_{maize}\right)$$

Where $M_{AD,t}$ is the methane produced in the year t $[m^3]$ and $MY_{substrate}$ is the methane yield of the respective substrates $\left[\frac{m^3}{ton}\right]$.

Table 9 - Table of Substrate Assumptions

Substrate	Percentage	Price	Methane Yield
Pig Manure	64.3	350 DKK/ton	12.2 m^3/ton
Cow Manure	22.6	350 DKK/ton	12.2 m^3/ton
Straw	7.5	590 DKK/ton	222.1 m^3/ton
Maize	5.5	867 DKK/ton	100 m^3/ton

Not all of the methane created is available for sale however, as some is used in the AD plant's boiler to create the necessary process heat. Some is burned in the torch due to downtime of the upgrading technologies, and some is lost in the upgrading process itself:

Equation 32 - Definition of Methane Lost due to Downtime

$$M_{torch,a} = M_{AD,t} * (100 - TA_a)$$

Here M_{torch} is the biogas burned in the torch due to downtime of the upgrading technologies $[m^3]$ and TA_a is the technical availability for each of the alternatives [%], describing the percentage of yearly production hours where the upgrading technology is available.

After some of the methane has been burned in the torch, the remainder will reach the upgrading system.

Both the AD plant itself, and some of the upgrading alternatives, need process heat, which is supplied by the at site boiler, which is powered by some of the produced biogas:

Equation 33 - Definition of Methane Used for Process Heat

$$M_{Boiler} = HR_{AD} * M_{AD,t} + HR_a * M_{PT,s}$$

WhereM_{Boiler} is the biogas burned in the boiler $[m^3]$, HR_{AD} is the heat requirement for the AD plant $[\%]$, and HR_a is the heat requirement for the alternative, if any[17] $\left[\frac{kwh}{m^3_{CH_4}}\right]$.

The process heat consumption is defined in accordance with the technology catalogue for renewable energy fuels, which define the heat requirements as a percentage of the output energy. The heat requirement in this paper is defined as a triangular distribution, based on the data in said catalogue (Energinet, 2019, p. 34).

After the aforementioned biogas has been burned in the torch and boiler, the remaining biogas gets sent to the upgrading facility. That amount is equal to the methane produced, minus what was burned in the torch and boiler:

$$M_{PB} = M_{ad,t} - M_{torch} - M_{boiler}$$

Here M_{PB} is the methane post boiler, the methane that is left after the boiler has been supplied $[m^3]$.

This is the amount that the alternatives upgrade, and from this amount that some is leaked:

Equation 34 - Definition of Methane lost in Upgrading Process

$$M_{Leak,a} = M_{PB} * PL_a$$

Here M_{Leak} is the biogas lost in the upgrading process itself $[m^3]$, and PL_a is the percentagewise loss of methane for each of the alternatives $[\%]$.

Equation 35 - Definition of Yearly Natural Biogas Available for Sale

$$NBG_{sale,t} = M_{AD,t} - M_{Torch,a} - M_{Boiler,a} - M_{Leak,a}$$

Where NBG_{Sale} is the upgraded biogas available for sale in the year t $[m^3]$,

Retirement Phase

The Retirement phase occurs at the end of the lifetime of the project, meaning the year 2040. The phase can be divided into two – the resale value of the components and the costs incurred by recycling, disposal and sale.

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[17] The HPWS technology has no heat requirements, and therefore that alternative only consumes the heat required by the AD plant.

The resale value will be equal to a percentage of the procurement cost, in accordance with the depreciation described earlier. The only exception to this will be the land cost, which is assumed to not have lost any value during the Operational phase.

The resale value of the respective component will be calculated in accordance with their expected lifetime and the lifetime of the project.

Equation 36 - Definition of Resale Value

$$RV_{com} = PC_{com} * \frac{LT_p}{LT_{com}}$$

Here RV_{com} is the resale value of the component in question $[DKK]$, PC_{com} is the procurement cost of the component in question $[DKK]$, LT_p is the expected lifetime of the project $[years]$, and LT_{com} is the expected lifetime of the respective components $[years]$.

Table 10 - Table of the technical lifetime of each part of the investment

Component	Lifetime [years]
AD plant	20
Upgrading technologies	20
Natural gas connection pipeline and control station	50
Electrolyser	25

For an exhaustive list of the cost incurring components, divided by phase and alternative, and how they were estimated, see appendix

Probabilistic Costing

This section deals with the first half of the 6th of 8 parts of the LCC, how to deal with uncertainty.

The costing in this paper will be conducted as part of a simulation. The construction of a simulation allows for costing of systems that do not exist yet, as well as investigating the uncertainty surrounding a system.

This paper will, in cases where the cost of a component or factor is uncertain, use probabilistic costing. In any case where uncertainty surrounds a factor, be it price, energy consumption, material usage or other, a probability distribution function (PDF) will be constructed, based on the sources available. A PDF is an expression of the distribution of a continuous random variable (Farr & Faber, 2018, s. 129). The constructed PDF's will then be used as part of a Monte Carlo simulation, to simulate the full variety of potential outcomes.

In this paper, whenever a factor is considered uncertain, the factor will be described with a distribution. Three different types of PDFs will be used, normal, triangular and uniform. A normal distribution is a symmetric, bell curved PDF, centered around a mean. Normal PDF's will be used when a significant amount data is available, so that a mean and standard deviation can be constructed. For the purpose of this paper, if the amount of reliable observations exceeds 25, a normal distribution will be assumed.

Triangular distributions will be used in cases where there is some dispute about the true value, but where a most likely value is present (Farr & Faber, 2018, s. 129), and there are not enough observations for a normal distribution. Uniform distribution will be used in cased where all outcomes are deemed to be equally likely (Farr & Faber, 2018, s. 129).

A Monte Carlo simulation is an iterative simulation. Instead of given a single result, it gives many different outcomes and gauges the probability of each outcome. The Monte Carlo simulations are useful when uncertainty surrounds a large number of factors. The simulation is constructed by describing the uncertain factors with a PDF. Each result in the simulation will choose randomly within that distribution for each factor. The advantage of this is, that the simulation does not only produce a range of possible results, but also how likely each result is.

For cost element which are paid in 1 year, the OpenLCA software will be used, as this software allows for simultaneous LCA and costing simulations and has an inbuild Monte Carlo function. As OpenLCA does not allow for easy discounting, any time dependent costs will be conducted in an excel sheet. Monte Carlo simulations has been used for both the LCC and LCA models. The LCC models were based on 10,000 results, and the LCA on 1,000 results[18].

Scenarios

This section deals with the second half of the 6th of 8 parts of the LCC. The first half dealt with probabilistic uncertainty. For some factors however, distributions are inadequate. Electricity costs for example are uncertain, but for the purposes of this paper it is useful to order results in accordance with electricity cost, which would not be possible if it was one of myriads of randomly generated numbers. Instead, scenarios are used.

As this paper is intended to support a decision-making process between three alternatives, several scenarios have been made. As the performance of the alternatives are reliant on factors outside the decision makers control, the construction of scenarios will help anticipate different futures, thereby incorporating some uncertainty analysis into the decision-making process.

[18] These were considered the upper limit, as any more slowed the excel documents to a halt. Originally the openLCA simulations were also done with 10,000 iterations, but these took eight hours to complete. As errors were found in the models, and the completion date closed in, the decision was made to reduce this to 1,000 iterations.

The scenarios will consist of two axes, one macroeconomic and another political. These two axes have been chosen on the basis that they will have a significant influence on the financial performance of the three alternatives. Each axis will consist of three scenarios, allowing for a total of nine different combination of scenarios.

The political axis is based on the IEA's World Energy Outlook, and their three scenarios, Current Policies, New Policies and Sustainable Development. These scenarios represent the policies being implemented towards combating climate change and global warming on an international level. Current Policies, as its name suggest only considers the policies that have already been implemented. New Policies include those they have been deemed to be likely to be implemented, based on the stated intentions of various governments and the framework already in place. Sustainable Development represent an effort to reach internationally agreed upon climate and energy goals, and the policies required to reach them.

For the purpose of this paper, the political scenarios manifest in two ways, natural gas price and electricity price. These were deemed to be the two factors that were most likely to affect the final results of the comparison. The natural gas prices are accordance with the price development for Europe, outlined by the 2018 version of World Energy Outlook. The electricity price projections were instead based on a Danish report, made by Dansk Energi (Capion & Larsen, 2017).

The IEA scenarios were chosen because they deliver price projections on relevant factors, and they are universally used. As such, both the Danish TSO Energinet (Energinet, 2018), the Danish Energy Agency (Energistyrelsen, 2018) and Dansk Energi (Capion & Larsen, 2017) all use World Energy Outlook as a basis for their energy price projections. The Dansk Energi scenarios were chosen on the basis that they were a single Danish source, providing a spectrum of different electricity prices.

The naming convention may be confusing, as the Dansk Energi's WEO 2016 prices were in fact based on the WEO's New Policies scenario – but in this paper, they are a part of the Sustainable Development scenario. This choice was made on the basis the "Sustainable Development" is the scenario with the highest prices, Current Policies the scenario with the lowest with New Policies in the middle.

Table 11 - Table of policy scenarios, detailing what factors are affected by the scenario, and from which sources the factors are based on

	Current Policies	New Policies	Sustainable Development
Natural Gas Price	IEA's Current Policy	IEA's New Policies	IEA's Sustainable Development

Electricity Price	Dansk Energi's Forward	Dansk Energi's Klima	Dansk Energi's WEO 2016

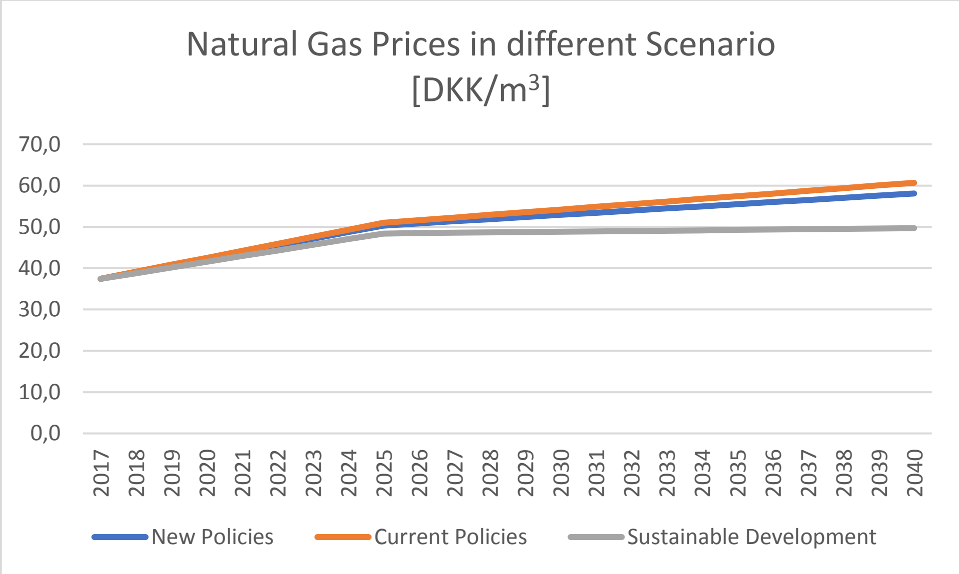

Figure 8 - Natural Gas prices in the different Scenarios

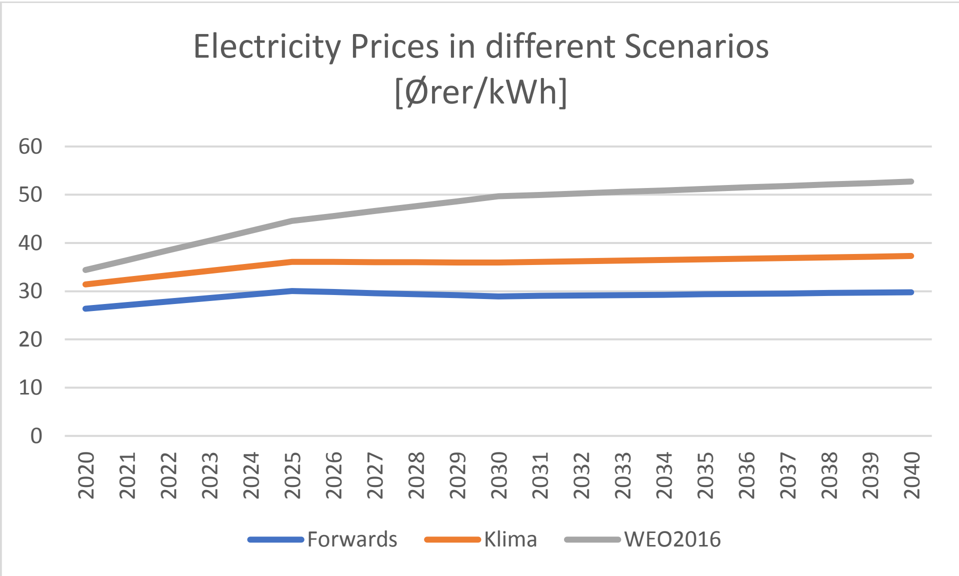

Figure 9 - Electricity Prices in the different Scenarios

The Macro Economic scenarios will consist of three factors: Gross Domestic Product development, Inflation Rate and Interest Rate. The GDP is an indicator of the economic growth of an economy (Chappelow, 2019). In this paper, the GDP development will be used as a factor for the increase in cost of labor-intensive factors, as was establish earlier (see Operational Phase). The inflation rate, manifested through the consumer price index, determines the "purchasing power" of a currency – the higher the inflation, the more expensive a good will be in a future purchase. In this paper, the price of any purchase made by the decision maker will be affected by the inflation rate (see Operational Phase). The Long-Term Interest Rate, in this specific context, as opposed the interest rate used in discounting, refers to “the prices at which the government bonds are traded on financial markets” (OECD, 2019). For the purpose of this paper, the Long-Term Interest Rate, together with the Inflation rate, determines the discount rate of the investment associated with the decision (see Equation 3 – Definition of CoE).

The Macro Economic will also be divided into three scenarios: Deflation, Baseline Growth and Intense Growth. These scenarios will be based on the economic performance of regions that have undergone these conditions. The Deflation scenario will be based on the averages of Japan between 1990 and 2005. The Baseline Growth scenario will be based on the averages of EU between 1980 and 2005. The Intense Growth scenario will be based on the averages of United States between 1990 and 2007.

Table 12 - Table of economic scenarios, detailing what factors are affected by the scenario, and from which sources the factors are based on

	Intense Growth	Normal Growth	Stagnation
Long term interest rate$[yearly\ \%]$	United States between 1990 and 2007 3.45	EU between 1980 and 2005 2.77	Japan between 1990 and 2005 1.5
Consumer Price Index $[yearly\ increase\ in\ \%]$	United States between 1990 and 2007 2.25	EU between 1980 and 2005 2.25	Japan between 1990 and 2005 0.46
Gross Domestic Product $[yearly\ increase\ in\ \%]$	United States between 1990 and 2007 3.31	EU between 1980 and 2005 2.54	Japan between 1990 and 2005 0.46
MRP	6.6	6.1	5.6
Lending Interest Rate	5	4.5	4

It could be argued that the two axes of the scenarios are not separate, but in fact tied together. For example, it can be argued that the economic performance of a region would influence the political decision made in the region, and conversely that the decision to combat climate change can influence the economy. For the purpose of this paper, the axis of the scenarios will be developed entirely separately. This is done due to the combined nature of the scenarios – their purpose is to encompass the interval of potential futures, not to give the nine most likely futures.

LCA

ILCD

A Life Cycle Assessment (LCA) is a method to gauge the environmental impact of a project or product. The “Life Cycle” part of the name refers to the cradle to grave approach that the method applies, meaning that every aspect, from resource extraction to recycling is included. The method does not aim to minimize the impact, but merely to give an assessment. This paper uses a consequential LCA approach, as opposed to an attributional. This means that the LCA looks at all activities that occur as a consequence of the project, including those that are avoided.

The International Life Cycle Data (ILCD) system was developed by the Joint Research Centre under the European Union. It was developed to give LCA practitioners a common ground on which to conduct their analysis, and to make their results comparable.

This LCA in this paper has been conducted in accordance with the guidelines as they have been described in the ILCD handbook (Institute for Environment and Sustainability, 2010). It does not, however, use the impact categories as has been defined by the ILCD, in the ILCD 2011 Midpoint+ method. This paper has instead elected for the RECIPE version – the reasons for this decision, as well what defines the ReCiPe method, is specified in the section titled RECIPE. Likewise, this paper cannot claim to be in compliance with the ILCD Handbook, for the simple reason that this paper does not follow the ILCD provisions. The reason for the noncompliance is not methodological, but partially that to claim compliance would require space which in this report is taken by the LCC portion and partially that strict ILCD compliance is not necessary for the intended audience.

While this paper cannot claim compliance with the ILCD Handbook, the LCA presented in this paper has been developed in accordance with the ILCD Handbook.

Functional Unit, Scope and Indented Audience

The functional unit is the center of the LCA. It is intended as a point of comparison between alternative systems. All LCA results are presented on the terms of the functional unit. This unit should be chosen to allow for direct comparison between alternatives (Institute for Environment and Sustainability, 2010, p. 60). In the case of this paper for example, a proper functional unit allows for the comparison of the alternatives, even though they produce different amounts of BNG.

The chosen functional unit in this paper is GJ. This allows for comparison between the alternatives, even though they produce different amounts of gas. It also allows for comparison with other fuels and energy sources.

As was the case in the LCC, the LCA also need a defined scope, under which circumstances the results can be considered relevant. The Spatial scope is Denmark. This does not mean that all resources are extracted on that country, but merely that the results of the Analysis cannot be applied to projects in other countries, however similar they may appear in other regards. This is due to the fact that the PFD has been developed in accordance with the Danish system – meaning that the biogas plant uses substrates as used in Denmark, the power production is based on the Danish system, the plant is based on Danish examples and so forth.

The temporal scope is 20 years, 2021-2040, which corresponds with the expected lifetime of the biogas plant.

The technical scope of this LCA is tried and tested technology at the time of writing – other than the currently in development BTF upgrading method. This choice was made to ground the LCA, as it is difficult to predict future technological developments.

The intended audience is a prospective investor into a biogas plant. The intent is that the LCA, together with the LCC portion of the paper can assist in the decision-making process. The LCA portion of the paper has been written with this in mind, hence the lack of strict ILCD handbook compliance. This is also the reason for the choice of impact categories – this point will be elaborated on in the RECIPE section.

RECIPE

The LCA method will determine the flow and their sizes, i.e. how much of CO_2 and methane is emitted to the air, and how much needs to be excavated. In order to determine the impact of said flows, the results then need to be characterized and classified, meaning that they are grouped together in Impact Categories.

Which Impact categories are included are included is determined by the chosen Impact Assessment Method. This paper uses the ReCiPe 2016 Endpoint Impact Assessment Method. This paper is intended to be help compare alternatives for a decision maker such as an investor, which are not expected to be experts in LCA methodology. Ease of interpretation is therefore important. The 18 Midpoint Impact Categories are therefore further grouped into the three Endpoint areas of protection: Damage to Human Health, Damage to Ecosystem and Damage to Resource Availability. The Endpoint areas of protection has a higher uncertainty, but are easier to interpret, as they give a better sense of the relevance of the LCA results (Huijbregts, et al., 2016, s. 13).

Damage to Human Health is measured in Disability Adjusted Life Years (DALY), counting the years lost and the years lived with a disability. Damage to Ecosystem is measured in species year and represent how much the project contributes to the extinction of species. Damage to Resource Availability is measured in the USD and represent the increase in cost of resources due to their depletion and extraction (Huijbregts, et al., 2016, s. 18).

When results are presented in this reported, the results have been further aggravated into a single score. This approach is called weighting, defined as "Converting indicator results of different impact categories by using numerical factors based on value-choices”. This is an approach that is potentially problematic, as the numerical factors are based on values, which are inherently subjective. Furthermore, with weighting, an unethical practitioner could potentially skew the results into different conclusion, by changing the numerical factors.

In order to counter this, the ReCiPe method allows for the use of the Individualist, Hierarchical and Egalitarian perspectives. These are strict scientifically created weighting systems, each representing a different grouping of mindsets. The Individualist perspective “is based on short term interest”, and has a short time horizon, looking at the next 10 to 20 years and only including the effects that are scientifically indisputable. The Hierachical perspective represents “the scientific consensus” and is somewhat in the middle of the three. The Egalitarian perspective represents the “precautionary perspective” and has the longest time horizons and the broadest list of included effects (Huijbregts, et al., 2016, s. 20).

The following weighting figures have been used

Table 13 - Weighting of the Individualist, Hierarchist and Egalitarian perspectives for the ReCiPe 2016 impact assessment method

Perspective:	Ecosystems	Human Health	Resources	Total
Individualist	250	550	200	1000
Hierarchist	400	300	300	1000
Egalitarian	500	300	200	1000

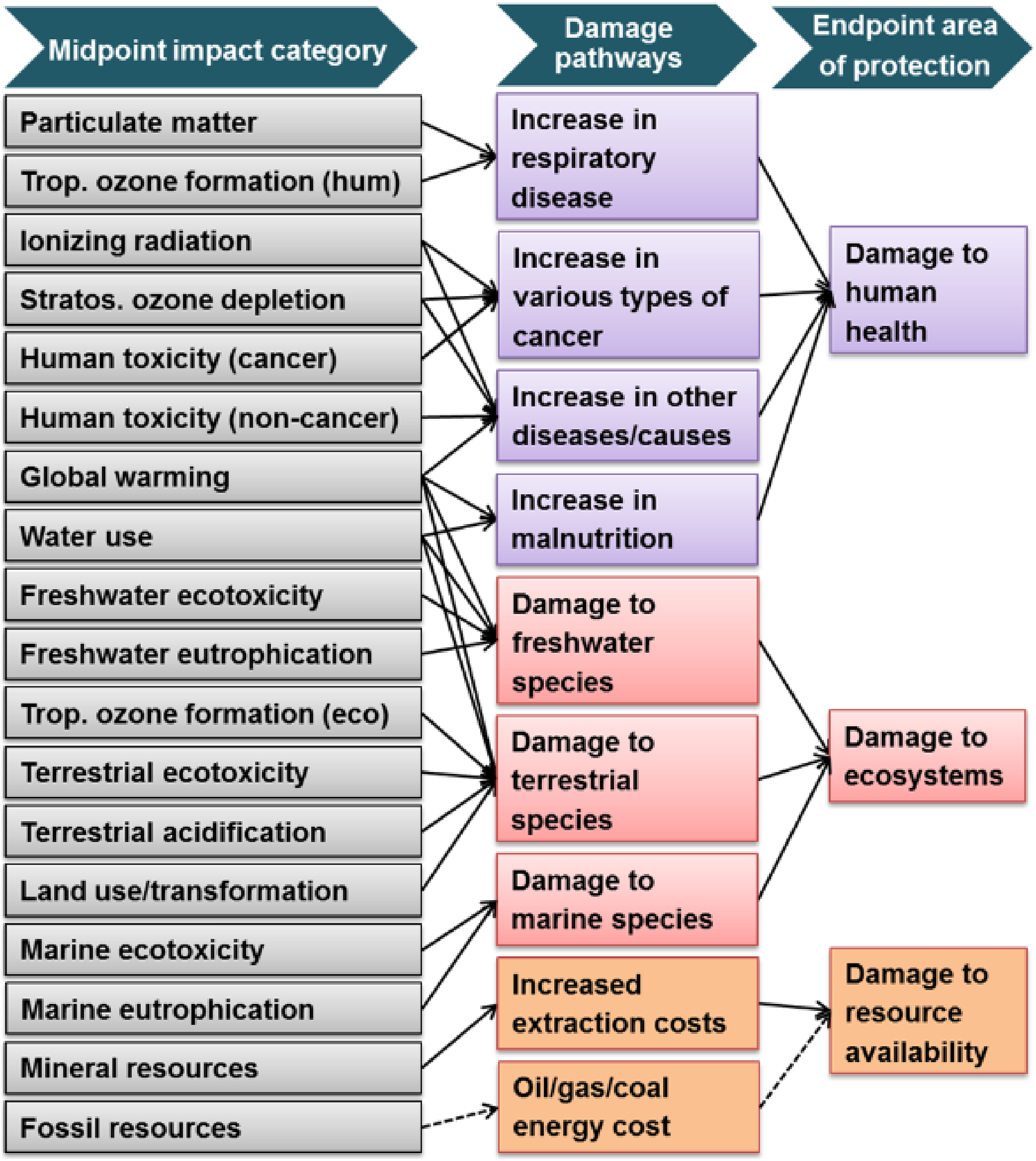

Figure 10 – Midpoint Impact Categories of ReCiPe 2016 and their relationship with the Endpoint areas of protection (Huijbregts, et al., 2016, s. 16)

Process Flow Diagrams

A Process Flow Diagram (PFD) is a diagram detailing the LCA model. It details the flows and products that goes into creating the functional unit.

A PDF consists of boxes and lines, with each box detailing a product or process that has been modeled as part of the LCA. The PFD details all that goes into the LCA, meaning that if the PFD does not contain it, it has not been included. The PDF is directed, with the lines going from one box, to another. Central to the PDF is the functional unit, emphasizing that all other processes occur as a consequence of this product.

A scribbled line and box designate an avoided flow or product. This avoidance has occurred as a consequence of the implemented project, and as such the consequences of that flow can be subtracted from the final result. For example, if an amount of pig slurry would normally be spread out on the field as fertilizer, but now will be stored inside as a consequence of a biogas plant using it as substrate, then the process of slurry spreading is avoided, and its consequences can be subtracted from the final result

This paper compares three alternatives, which all have a lot in common, namely the same biogas plant. As such, this paper contains four PFD's: one detailing the construction and operation of the biogas plant itself, and three detailing the three alternative methods of upgrading the biogas. When reading the AD PFD, a box labeled "Upgrading of Biogas" appears. Each of the three alternatives may be substituted into one this box, for the respective LCA's.

The anaerobic digestion plant modelled in the LCA is the same that was cost estimated in the LCC, meaning that the same material components are in place. Some immaterial components are lacking, such as the insurance and labor costs, as they are deemed to have a direct environmental impact. Conversely, some flows have been added, as they do not have an internalized monetary cost for the investor, but does has an environmental impact, such as the storage of slurry and the avoided natural gas production.

The PDFs are intended as an overview, not a detailed description. For an exhaustive description of the different processes, see appendix Appendix 5 – LCA inventory – BTF, Appendix 6 – LCA inventory – HPWS, Appendix 7 – LCA inventory – Chemical Absorption and Appendix 8 – LCA inventory – AD.

BTF

The BTF PDF is based on the same sources as the work breakdown structure. As such there is relatively little new information added. The primary difference is that where the uncertainty in the LCC was centered around monetary cost, in the LCA the uncertainty is centered around material choice and material amount.

The BTF construction is based on Figure 11, with the additions and changes that is in accordance with the original experiment (Dupnock & Deshusses, 2017).

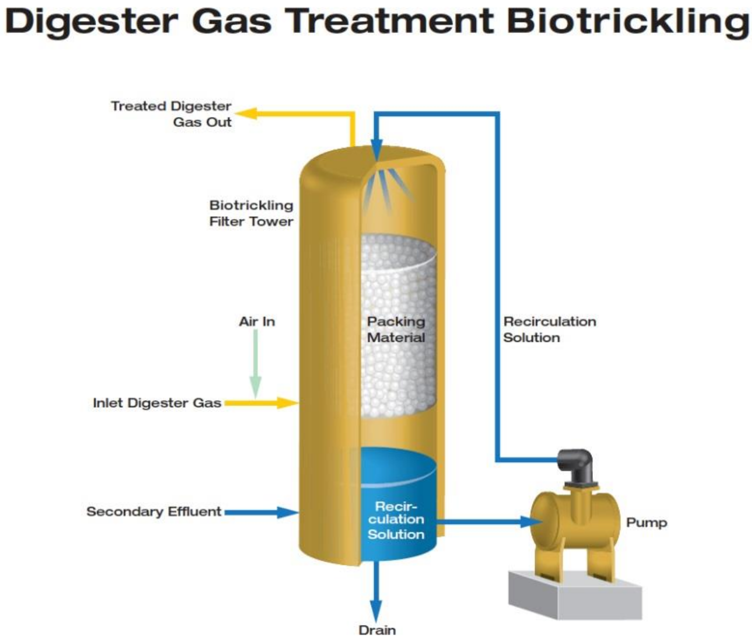

Figure 11 - Schematic of a Biotrickling filter (AAEES, 2019)

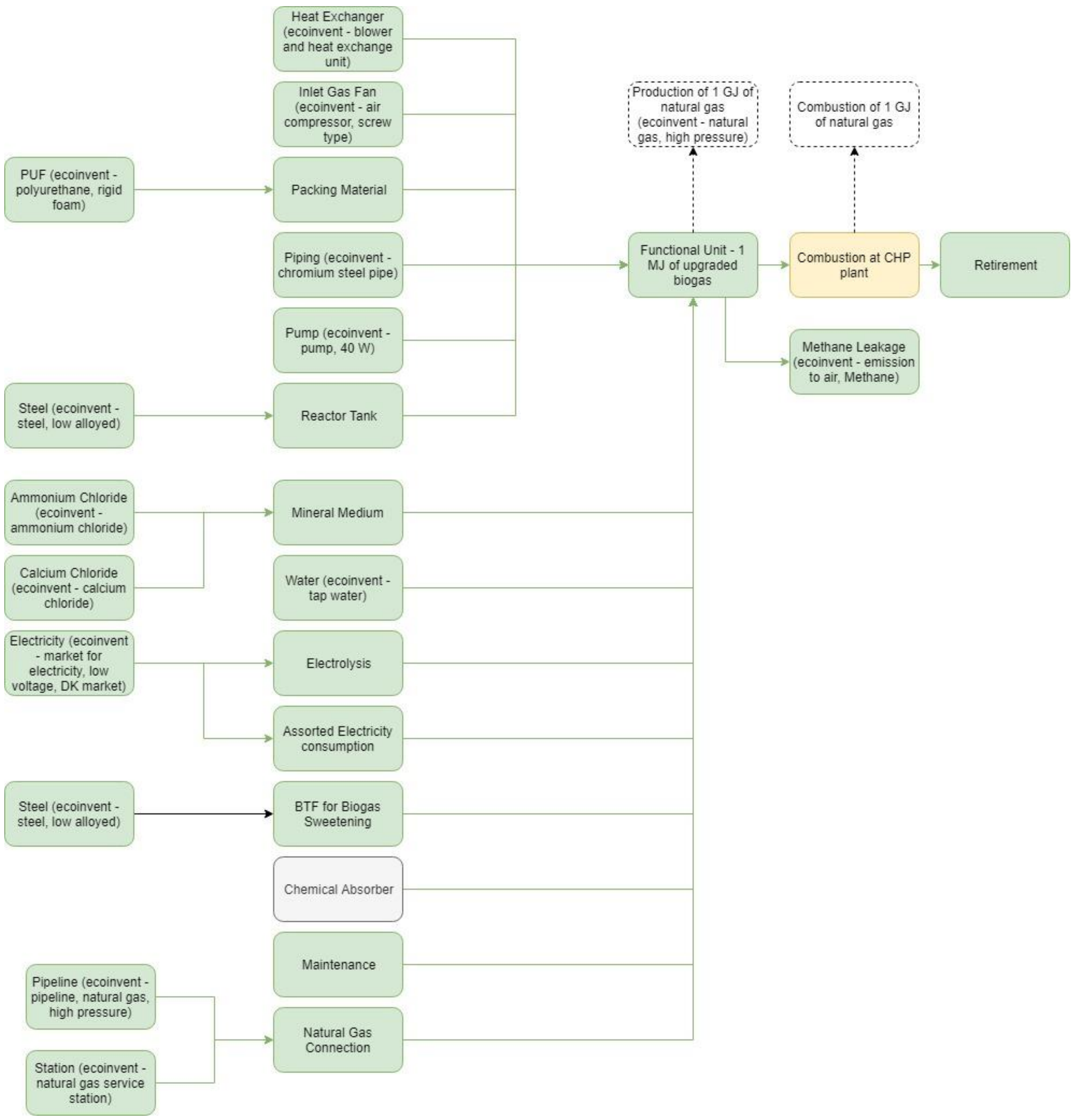

Figure 12 - Process Flow Diagram of the BTF upgrading technology

HPWS

The water scrubber was not cost estimated using the engineering method, such as the AD plant and BTF was. As such, the PFD of this alternative is much more elaborate than the WBS of the water scrubber would imply. The PFD is based partially on the schematic of a scrubbing plant made by the company Malmberg, of the type GR 28, partially by a principle sketch. The operation of the water scrubber is modeled in accordance with the information gathered for the LCC portion, although the data has been altered to fit with the functional unit. The construction of the HPWS is based on Figure 13 and Figure 14.

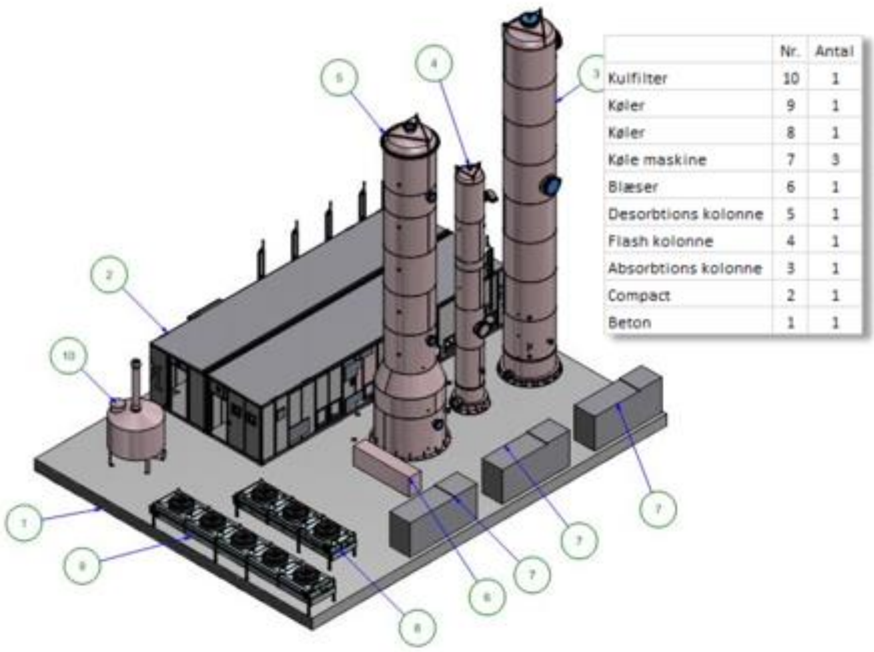

Figure 13 - Schematic of a HPWS plant (Henriksen, 2015, s. appendix 1, p. 6)

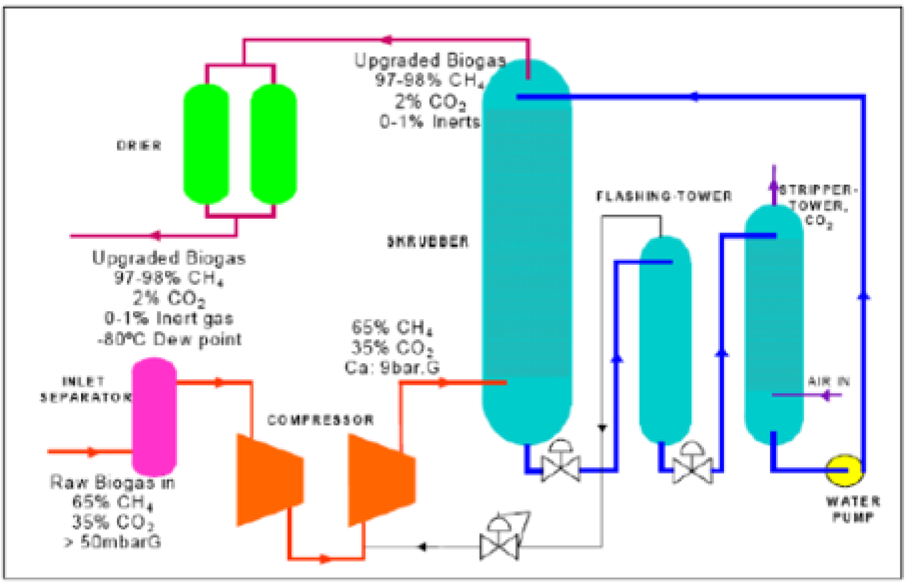

Figure 14 - Principle Schematic of a HPWS plant (Henriksen, 2015, s. appendix 1, p. 16)

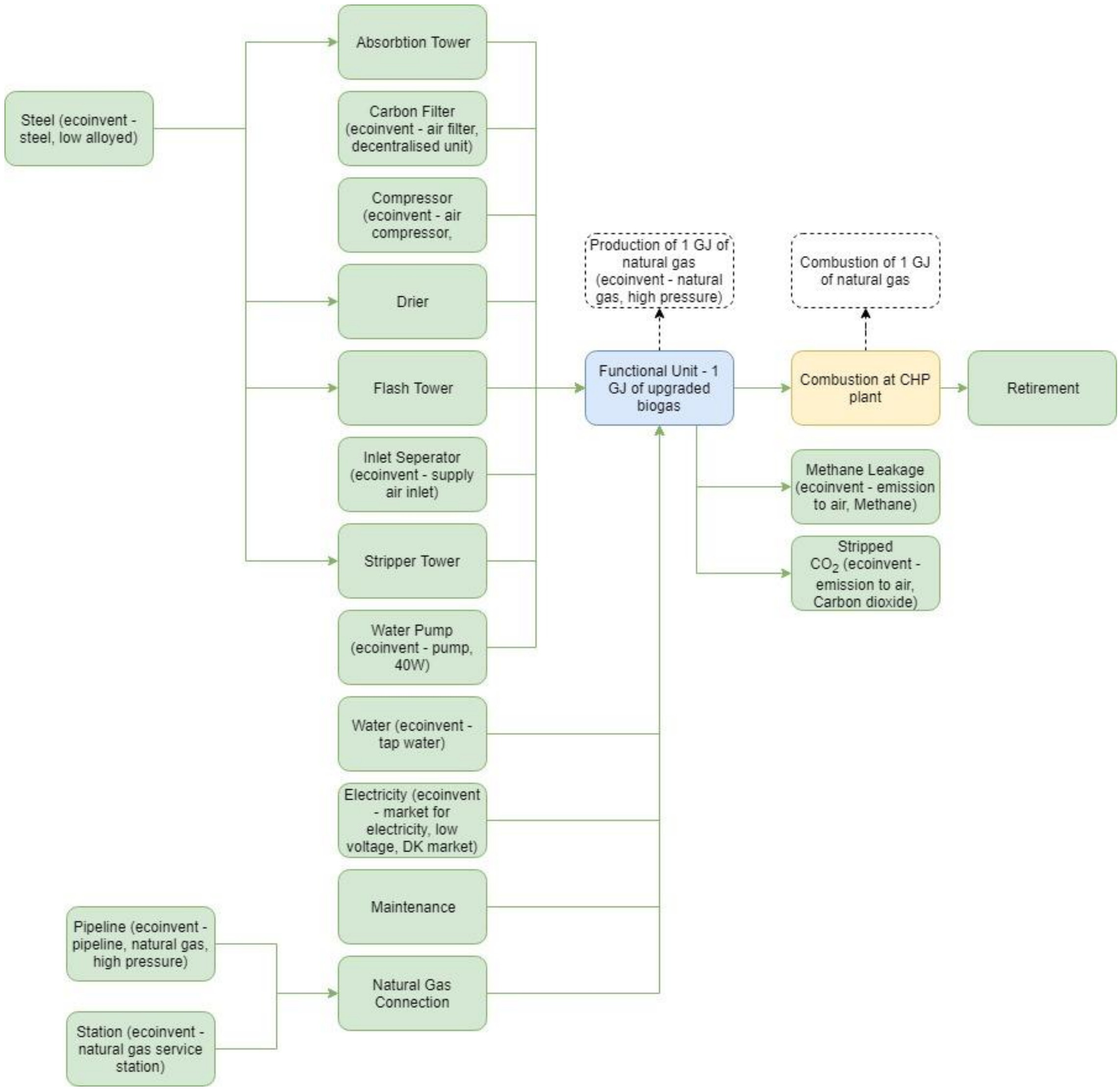

Figure 15 - Process Flow Diagram of the HPWS upgrading technology

Chemical Absorption

As was the case of the water scrubber, the chemical absorber also needs to be modeled differently than the LCC. The chemical absorber is being modeled on a schematic made by the Danish Gas-technical Center. As in the case of the water scrubber, the operation of the chemical absorber is modelled in accordance with the data gathered for the LCC portion.

The construction of the chemical absorber is based on

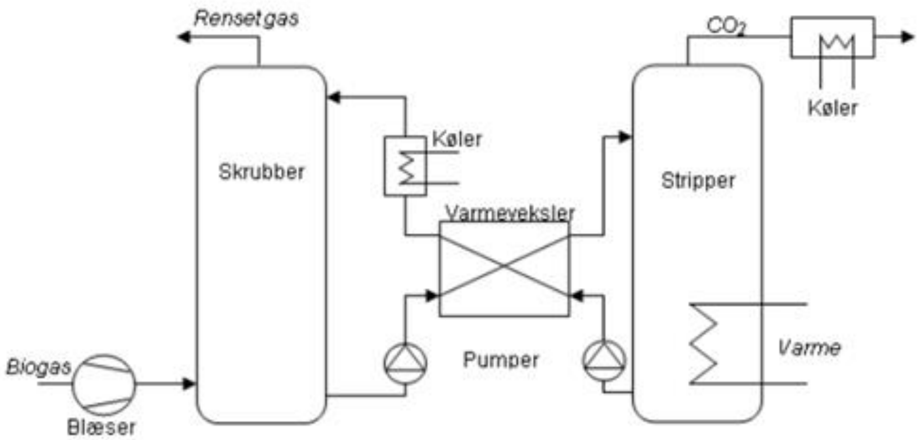

Figure 16 - Principle Schematic of a Chemical Absorber (Kvist, 2018, s. 8)

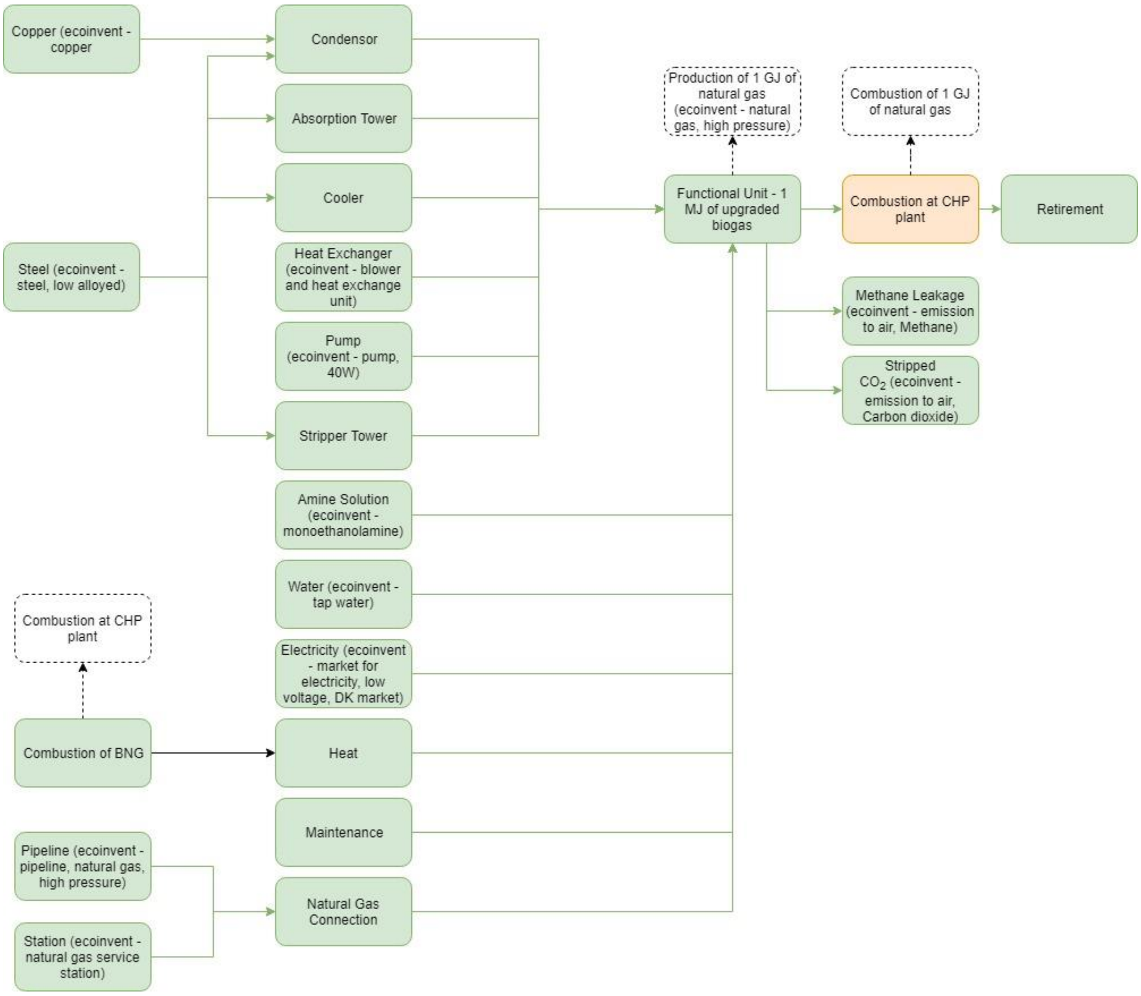

Figure 17 - Process Flow Diagram of the Chemical Absorption upgrading technology

AD

The AD plant, much as in the case of the LCC, is a part which all three alternatives have in common. This has been divided into two parts, in an attempt to increase clarity. The first details the plant itself, the components used and how they are modelled. The second part details the substrate used and the consequences of their use.

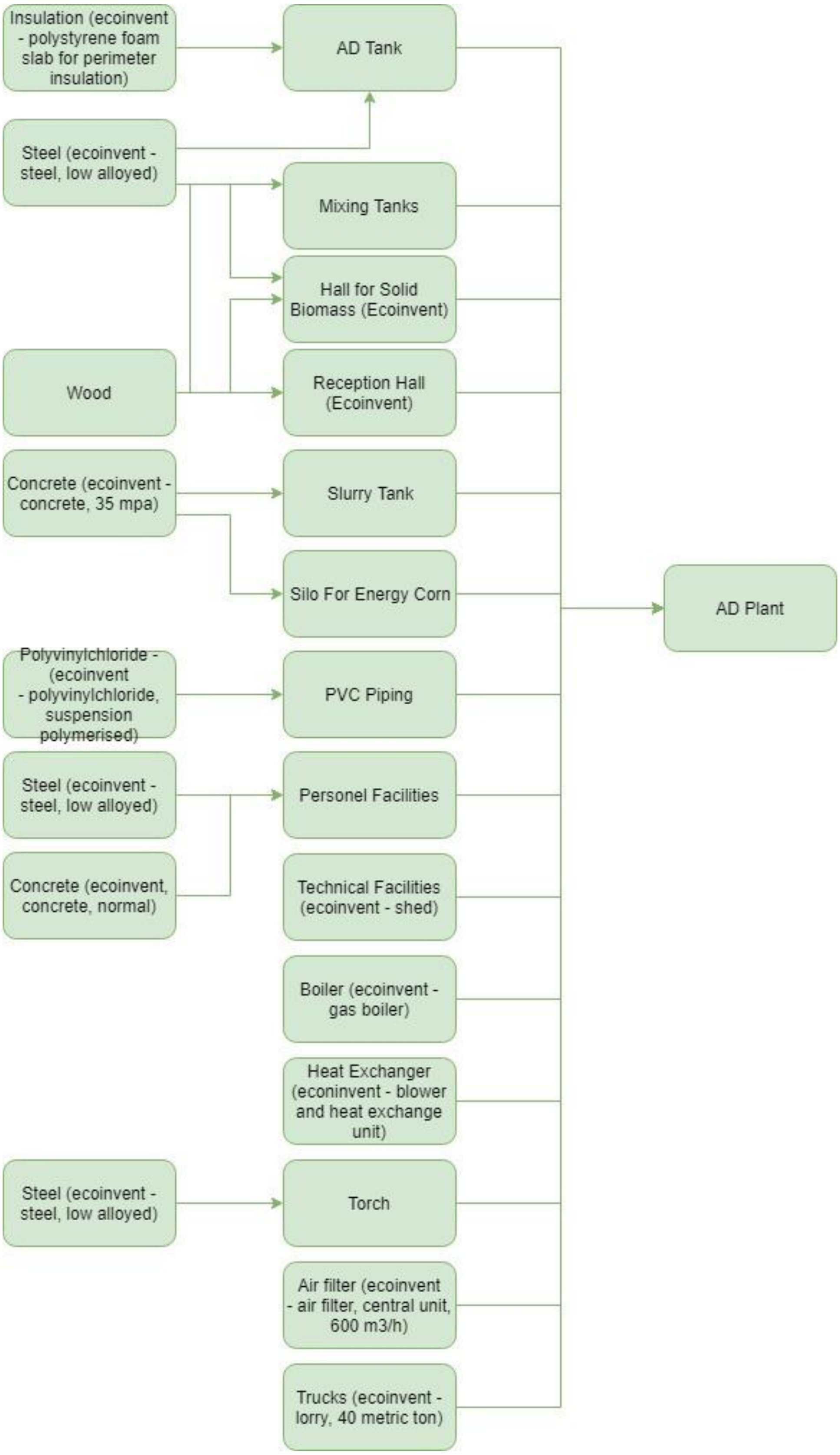

Figure 18 - Process Flow Diagram of AD Plant

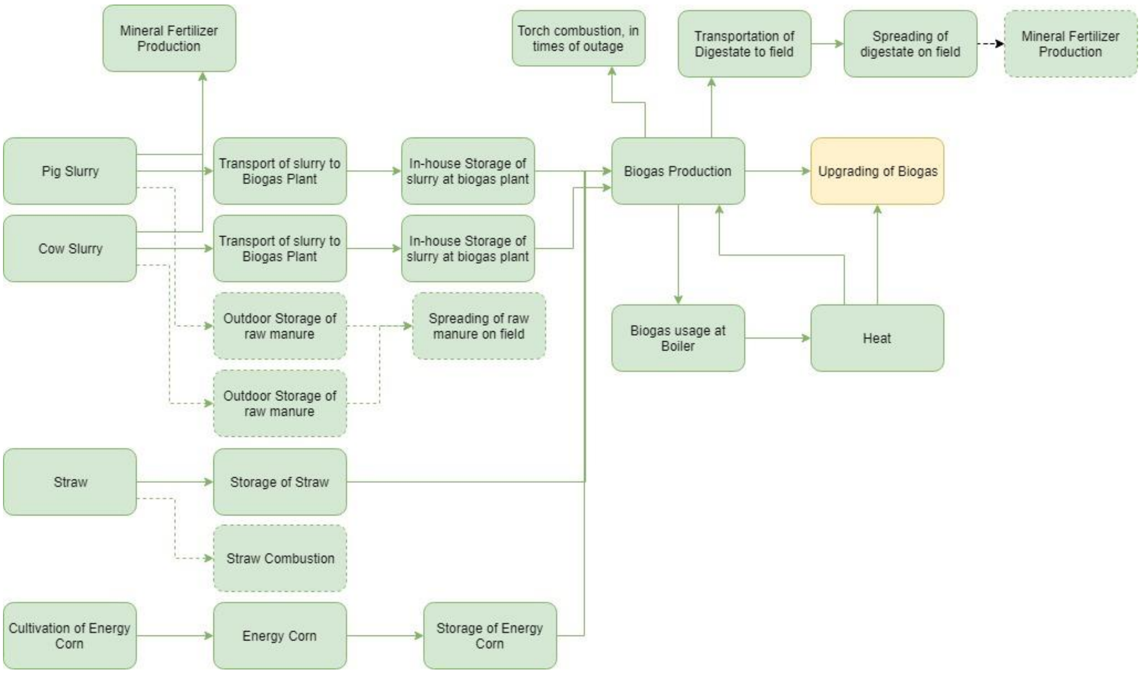

Figure 19 - Process Flow Diagram of substrate usage by the AD plant

Data Collection

The data used to construct the LCA has been collected from a variety of different sources. As a basis, the LCA used the 2018 version of the Ecoinvent consequential database. The Ecoinvent database consist of thousands of entries, from simple elementary flows like hydrogen to complex products like truck manufacturing, usage and recycling.

Whenever possible, other LCA's have been used, in particular when it comes to the substrates used, as well as the digestate and spreading of fertilizer. These components of the PFD were considered to have such a high impact on the final results, that reliable data was considered to be alpha and omega. This is why up to date LCA's, conducted on Danish conditions were used. In these cases, the work required to model the processes manually were deemed to be necessary.

In the case of modelling the Danish energy system – specifically the natural gas production and electricity production – the Econinvent database was used. This is a potential source of inaccuracy, as these are likely to have a significant impact on the final result. The choice to rely on Ecoinvent instead of modelling them manually was based partially on the fact that ecoinvent has included localized data and partially based on the workload required to model the Danish energy market being beyond the scope of this paper.

For complex components, such as heat exchangers and pumps, which are likely to consist of many different materials, the Ecoinvent database was used, when it supplied said components. This was done primarily for smaller components which are expected to have little impact on the final results, as the Ecoinvent database rarely included components that exactly equaled what was required.

For “simple” components, made out of a single or two materials, such as the concrete siloes, or the steel digestion tanks, the construction of the component was simulated. This was done by assessing the material used as well as the amount, via an analogous source. This was then added into the model, by adding the production of the appropriate materials into the model, as specified Ecoinvent database.

Whenever it was possible to discern what specific material was used, then the product was modelled using that material – if Ecoinvent contained it. If the database did not contain it, or if no source specified the exact material, then a representative material was used instead. If, for example, the source did not specify the type of steel being used, the model assumes that it was “steel, low alloyed”. If, on the other hand, it was possible to discern that a silo must be made of concrete with a strength of 35 MPA, which the database contains, then that material was used.

Results

The time has now come for the 6th of 8 parts of the LCC, presenting the results of the modelling.

The LCC results have been divided into each alternative. A contribution tree has been constructed for both the LCC and LCA, detailing how each component contributes to the final result.

LCC

BTF

The NPV of the BTF alternative is positive in most scenarios – however it also has a significant margin of error, due to the vast amount of uncertainties involved in cost estimating a technology that is still in development.

Table 14 - The mean NPV results for the BTF alternative

	Intense Growth	Normal Growth	Stagnation
Current Policies	DKK 96,927,510.30	113,841,708.32	DKK 225,445,800.21
New Policies	DKK 30,563,398.41	DKK 43,256,282.26	DKK 147,249,813.11
Sustainable Development	DKK -76,511,203.96	DKK -69,751,727.02	DKK 20,444,023.49

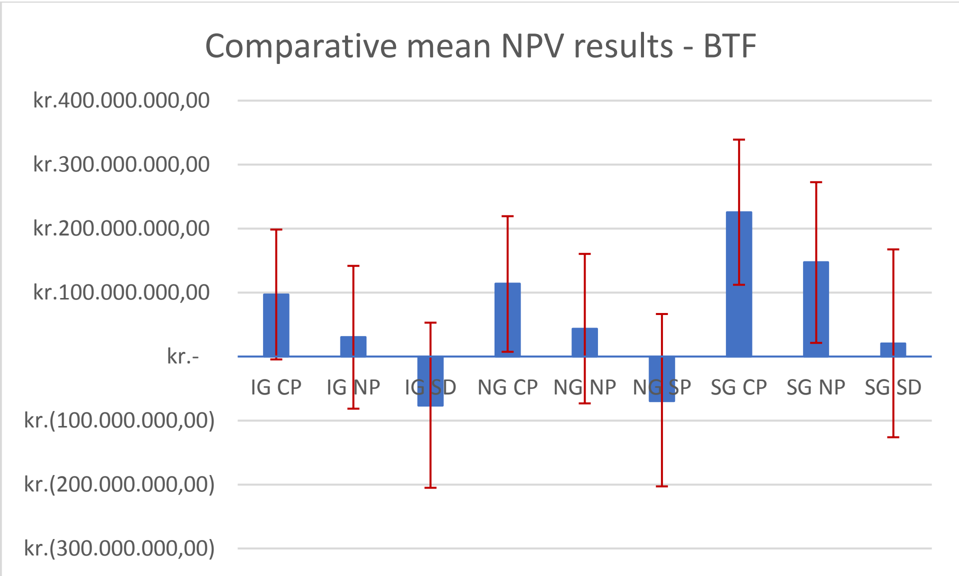

Figure 20 - Comparative results of NPV, BTF alternative, with blue indicating the mean, and red indicating the 5th and 95th percentiles

HPWS

The HPWS is positive in all 9 scenarios, outperforming the BTF in all but one of them, as well as showing a much tighter grouping in the distribution of results.

Table 15 - Mean NPV Results - HPWS alternative

	Intense Growth	Normal Growth	Stagnation
Current Policies	DKK 167,104,393.5	DKK 184,391,403	DKK 208,793,518.9
New Policies	DKK 163,405,412.1	DKK 181,154,958.7	DKK 205,200,637.3
Sustainable Development	DKK 150,916,578.95	DKK 176,733,570.4	DKK 198,821,732.1

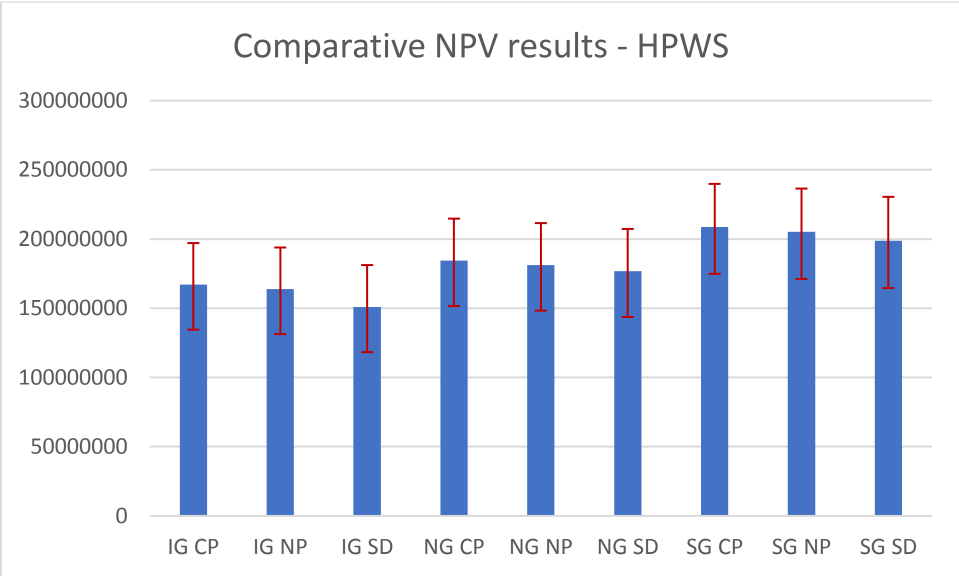

Figure 21 - Comparative results of NPV, HPWS alternative, with blue indicating the mean, and red indicating the 5th and 95th percentiles

Chemical Absorption

The chemical absorber also shows positive NPV's in all scenario, trailing just behind the HPWS. It should be noted however, that the distributions of the Chemical Absorber and HPWS do overlap, essentially showing the results to be more or less identical.

Table 16 - Mean NPV Results - Chemical Absorption alternative

	Intense Growth	Normal Growth	Stagnation
Current Policies	DKK 142,854,436.7	DKK 150,520,687.1	DKK 191,941,152.6
New Policies	DKK 139,636,814.5	DKK 147,130,512.5	DKK 174,973,582.6
Sustainable Development	DKK 125,131,263.9	DKK 142,444,417.7	DKK 164,556,510.6

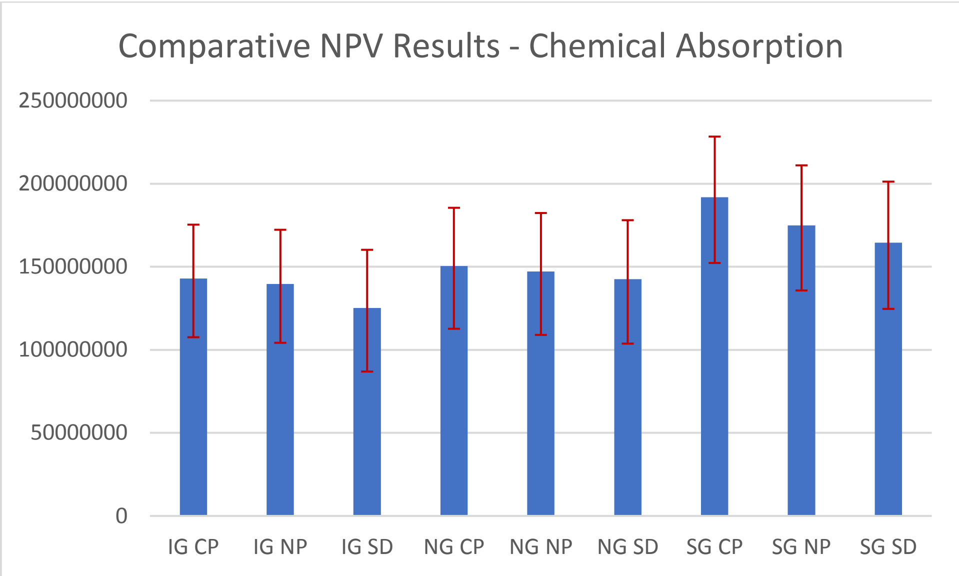

Figure 22 - Comparative results of NPV, Chemical Absorption alternative, with blue indicating the mean, and red indicating the 5th and 95th percentiles

LCA

Hierarchal

All scenarios have a negative impact – which is good, as the larger the impact, the more damage is inflicted to human health, ecosystems and resource availability. All results are presented per the functional unit, being GJ of power to the CHP. Under the hierarchist perspective, the BTF scores better in climate change as it has the largest negative impact.

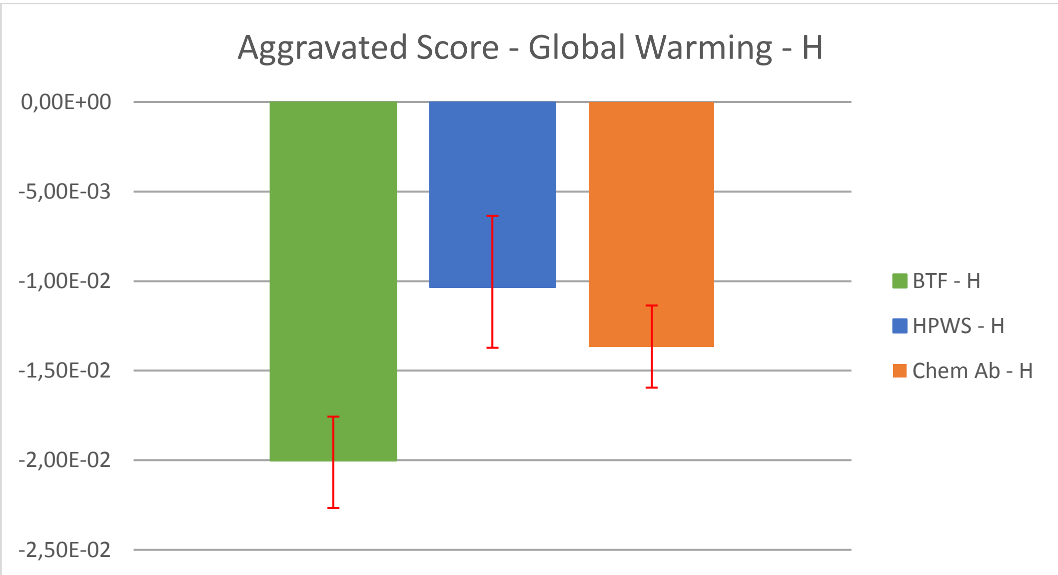

Figure 23 - Aggravated Score of Global Warming of the three alternatives - Hierarchist Perspective. Mean scores, with 5th and 95th percentiles as error bars.

The situation is slightly different in the single aggravated score, but the results are so close, and that the distributions overlap, essentially making it impossible that any is better than the others.

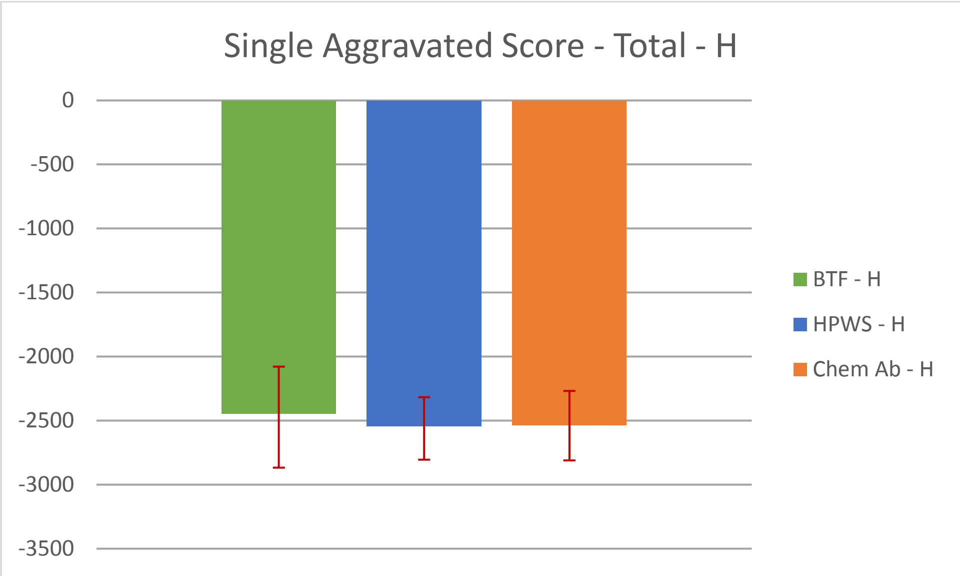

Figure 24 - Single Aggravated Score of the three alternatives - Hierarchist Perspective. Mean scores, with 5th and 95th percentiles as error bars.

Egalitarian

Under the egalitarian perspective, the same pattern is seen, with the BTF having the largest negative impact. The difference is even greater in this case, indicating that the BTF impact consists of flow that are more heavily considered in this perspective.

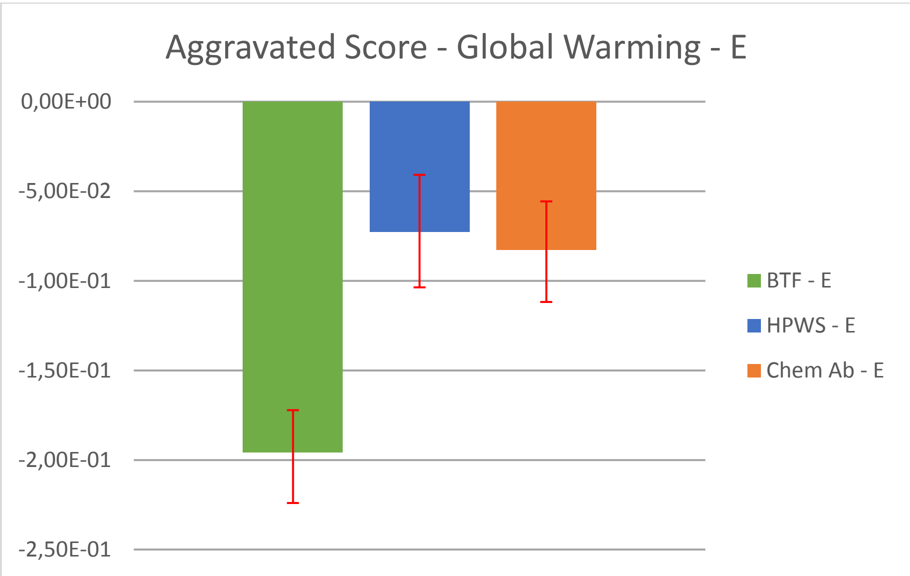

Figure 25 - Aggravated Score of Global Warming of the three alternatives - Egalitarian Perspective. Mean scores, with 5th and 95th percentiles as error bars.

In the single aggravated score, the Egalitarian perspective has not changed anything, with all three alternatives scoring essentially the same.

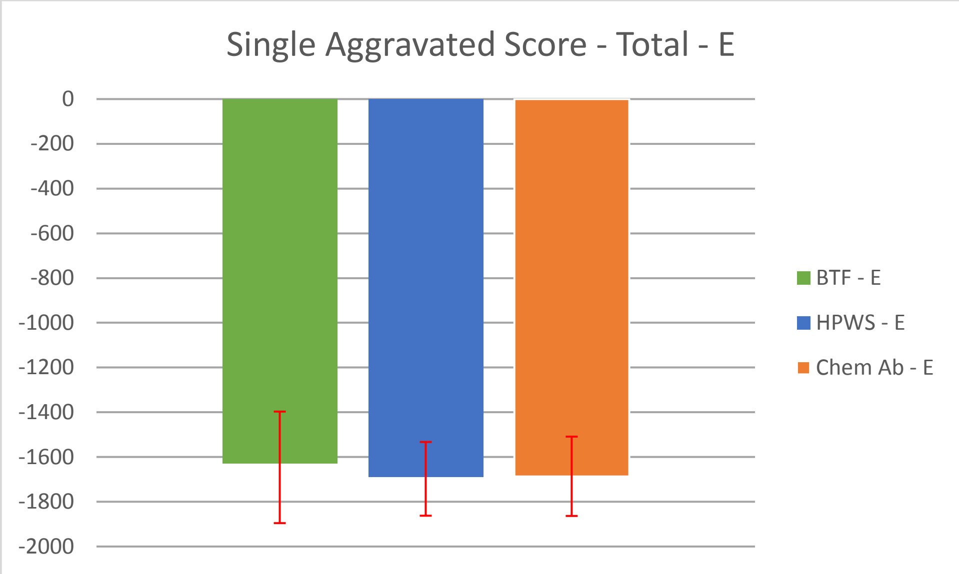

Figure 26 - Single Aggravated Score of the three alternatives - Egalitarian Perspective. Mean scores, with 5th and 95th percentiles as error bars.

Individualist

Under the individualist perspective, the global warming results have slightly changed, with the Chemical Absorber now competing with the BTF for the best performing alternative

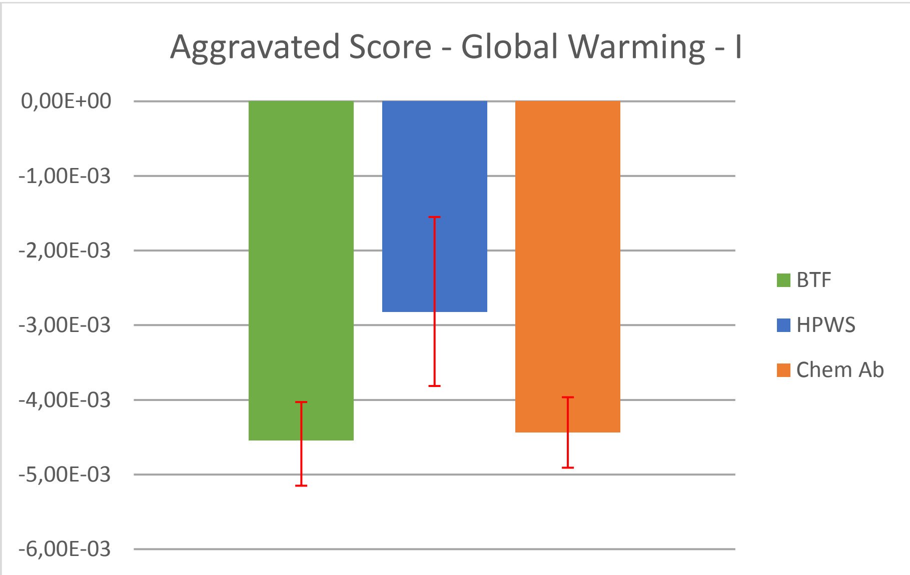

Figure 27 - Aggravated Score of Global Warming of the three alternatives - Individualist Perspective. Mean scores, with 5th and 95th percentiles as error bars.

The individualist perspective does not change anything for the single aggravated score – once again the alternatives are the same.

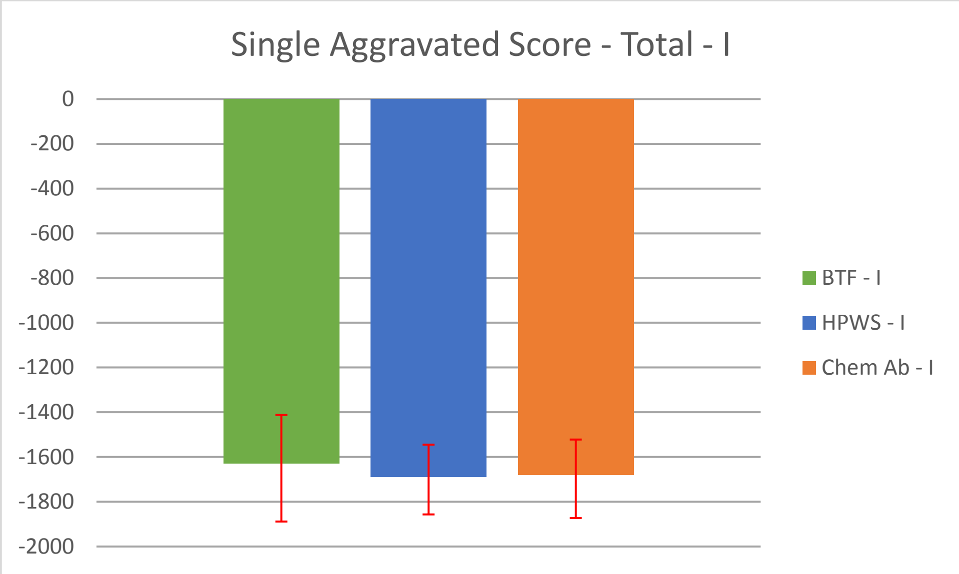

Figure 28 - Single Aggravated Score of the three alternatives - Individualist Perspective. Mean scores, with 5th and 95th percentiles as error bars.

When comparing the results, it is clear that the egalitarian perspective considers the alternatives to be much better than the other perspectives.

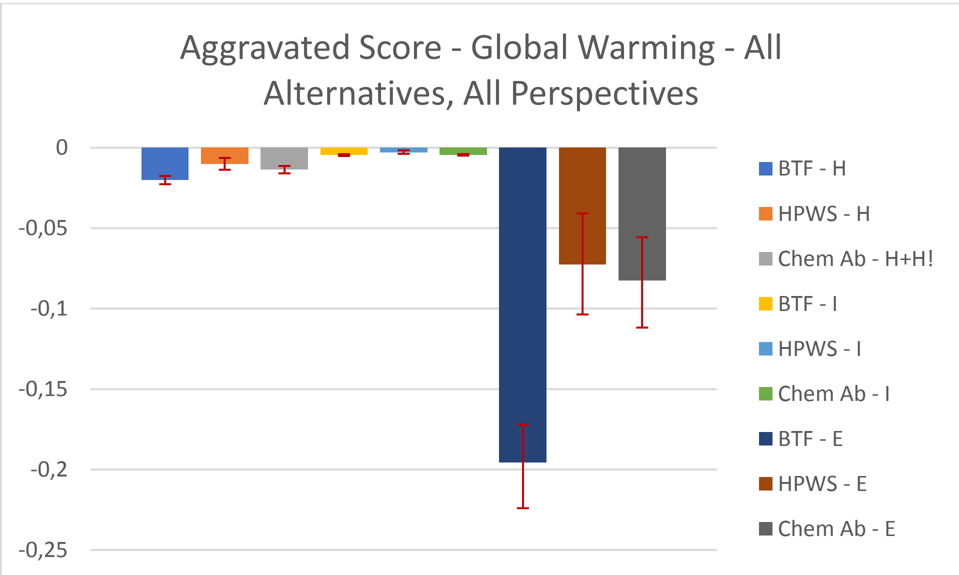

Figure 29 - Aggravated Score of the three alternatives - side by side comparison of all scenarios, all perspectives. Mean scores, with 5th and 95th percentiles as error bars.

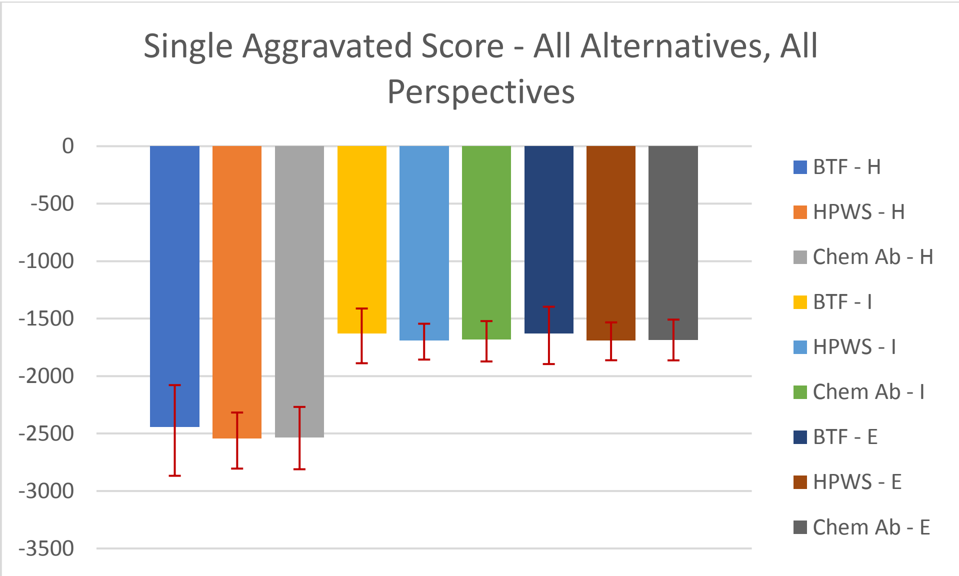

Figure 30 - Single Aggravated Score of the three alternatives - side by side comparison of all scenarios, all perspectives. Mean scores, with 5th and 95th percentiles as error bars.

Contribution Trees

The contribution tree show which processes and components has the greatest contributions to the final result. As Monte Carlo simulations give thousands of results, each slightly different, a single contribution tree will not be accurate for all results. Instead the contribution trees were based on a single result that were deemed to be most representative. The LCC contribution tree was based on the mean result for each component from "Normal Growth, Current Policies" scenario. The LCA contribution trees were based on the "most likely" of factors – for normal distributions, the mean was used, for triangular distributions, the most likely figure was used and for uniform

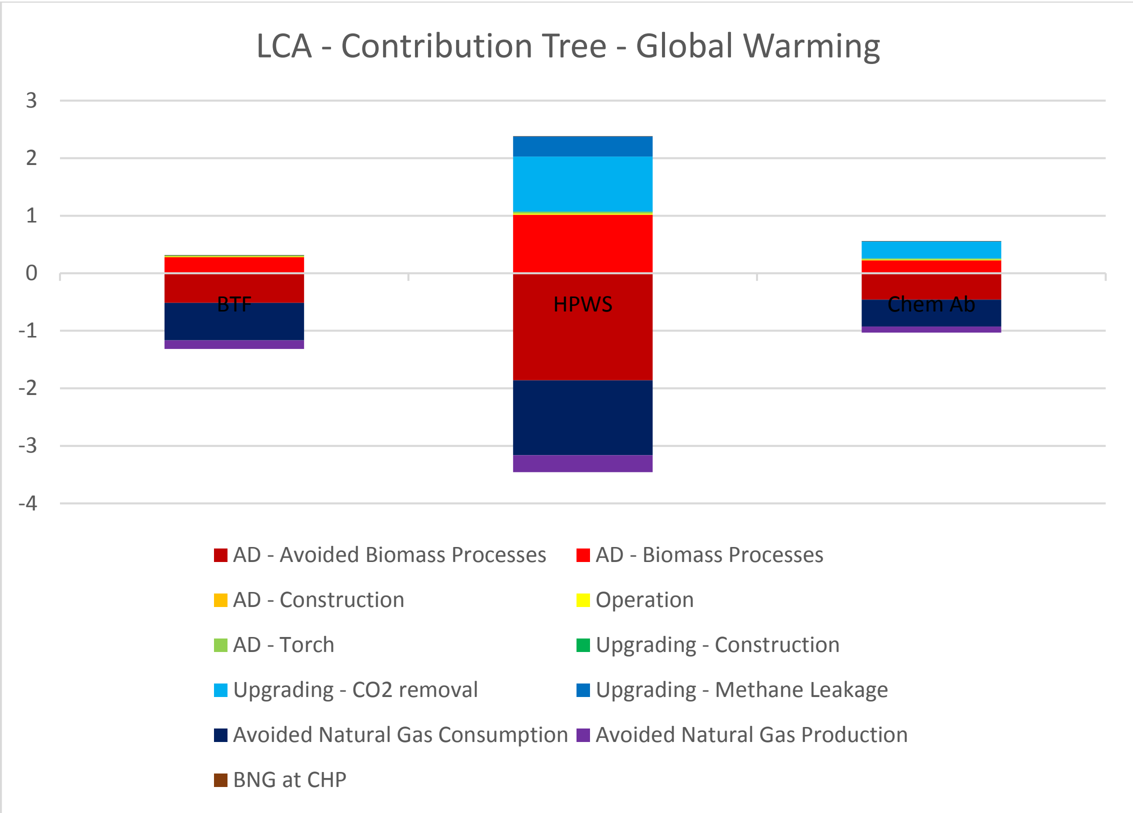

Figure 31 - Contribution Tree for the LCA results of each alternative, for the Aggravated Score of Climate Change.

The contribution tree for the single aggravated score reveals conclusively why the single aggravated score is essentially identical across alternatives. The only real impact that is considered is the avoided Natural Gas Production, overwhelming all other contributors. Whith all alternatives displacing approximately 1 GJ of natural gas per GJ of BNG, the single aggravated score does not leave room for much variety between the different alternatives.

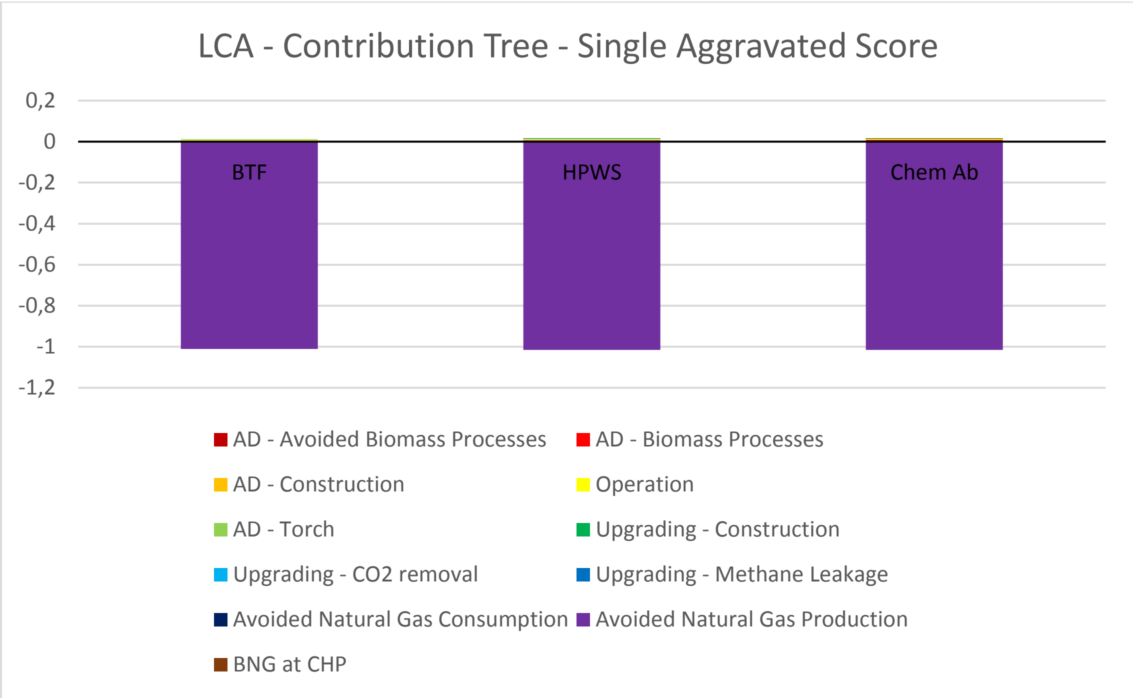

Figure 32 - Contribution Tree for the LCA results of each alternative, for the Single Aggravated Score

The LCC contribution tree shows that there is one single cost factor which dominates the BTF result, which is electricity costs. For HPWS and Chemical absorption, this place is taken by the substrate costs. For the BTF alternative, with its higher BNG output for the same substrate intake, the relative size of the substrates is much less significant. After that comes labor, maintenance and construction as the largest contributors.

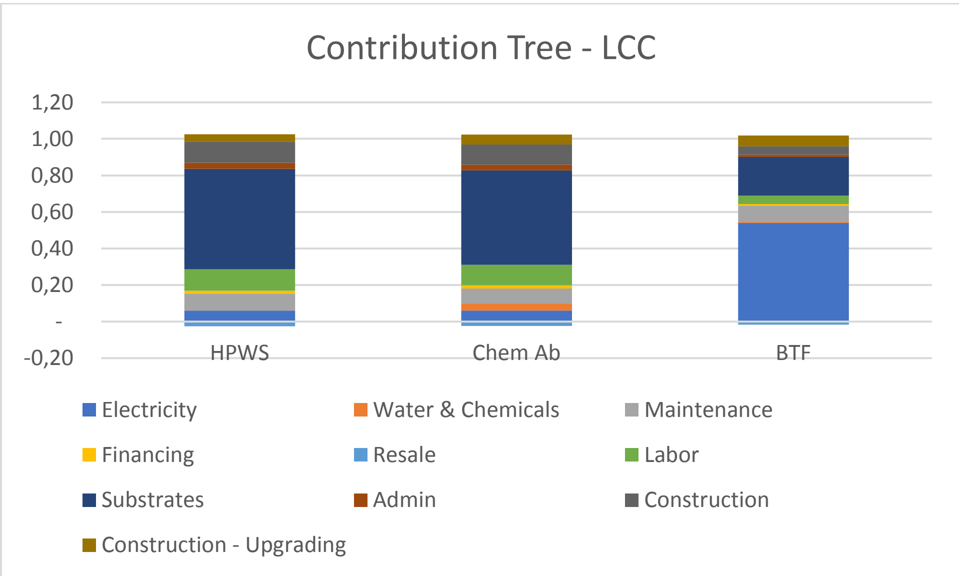

Figure 33 - Contribution Trees for the LCC

Best Performer

The best performer, being the alternative with the highest positive npv is, in all scenarios bar one, the HPWS – however the HPWS and Chemical absorber are so close, that the distribution of their performances overlaps. As such, this paper cannot claim to have determined a significant difference in their viability as an investment between the two.

As for the BTF alternative, it only scores the highest NPV in one of the nine scenarios, that being the Current Policies – Stagnation. However, with the large uncertainty inherent in the BTF scenario, this cannot be claimed to be superior, as the distribution of results overlap with both the HPWS and Chemical Absorber.

Table 17 - Best performing alternative in each scenario

	Intense Growth	Normal Growth	Stagnation
Current Policies	HPWS DKK 167,104,393.5	HPWS DKK 184,391,403	BTF DKK 225,445,800.21
New Policies	HPWS DKK 163,405,412.1	HPWS DKK 181,154,958.7	HPWS DKK 205,200,637.3
Sustainable Development	HPWS DKK 150,916,578.95	HPWS DKK 176,733,570.4	HPWS DKK 198,821,732.1

When looking closer at the Stagnating economy, Current policies scenario, it is evident that while the mean result is higher than the HPWS scenario, a significant part of the distribution of results actually still scores lower than the HPWS.

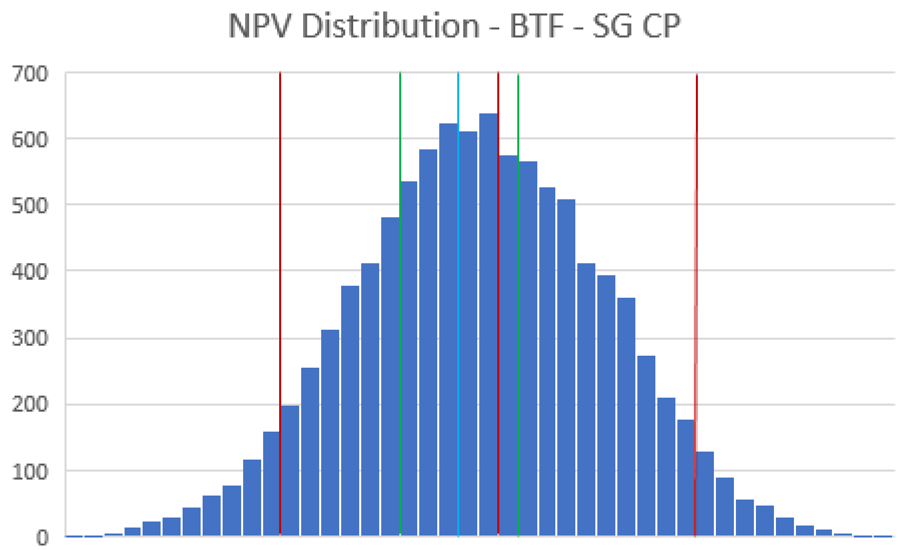

Figure 34 - The Distribution of results, BTF alternative, Stagnating Growth, Current Policies scenario. Red and Green indicate the 5th percentile, mean and 95 percentile of the BTF and HPWS alternatives in said scenario, respectively

Hypothetical Scenarios

To further investigate the impact of the electrolysis on the BTF's performance, a few extra illustrative scenarios have been constructed. If, for example, the electrolysis technology was to mature faster than expected, and perform at the expected levels of the years 2030 and 2050, the BTF alternative could be expected to perform significantly better.

Table 18 - The NPV of the BTF alternative if the electrolyser functioned according to expected levels of the years 2020, 2030 and 2050

	2020 Electrolysis	2030 Electrolysis	2050 Electrolysis
NPV NG NP - BTF	DKK 43,256,282.26	DKK 97,261,097.62	DKK 124,243,439.90

No other factor has been touched, and only the mean results of the Normal Growth, New Policies scenario is included in the table.

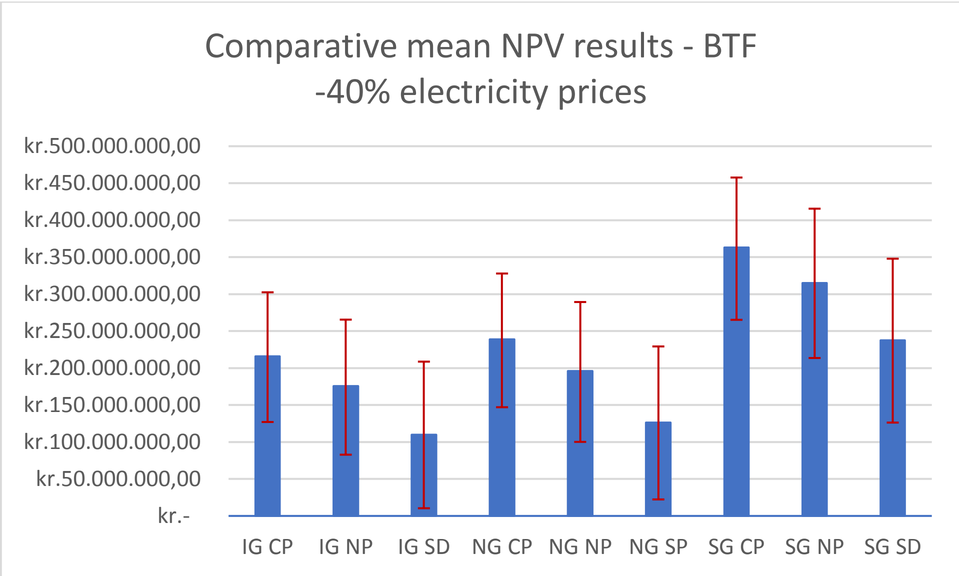

Figure 35 - Mean NPW results of hypothetical scenario, - 40 % electricity prices

Likewise, if this were combined with a change in electricity cost, the benefits would be further increased.

Table 19 - Mean NPV results of BTF alternative in Normal Growth, New Policies scenario, in hypothetical scenarios - different electricity prices and electrolysis maturities

	2020 Electrolysis	2030 Electrolysis	2050 Electrolysis
-40 % Electricity Prices	kr. 195.811.149,86	kr. 236.208.375,64	kr. 256.778.915,70
-20 % Electricity Prices	kr. 119.535.191,09	kr. 166.734.827,32	kr. 190.508.407,05
+ 20 % Electricity Prices	kr. -33.019.456,13	kr. 27.785.623,26	kr. 57.977.987,27
+ 40 % Electricity Prices	kr. -109.297.099,31	kr. -41.689.601,94	kr. -8.288.360,84

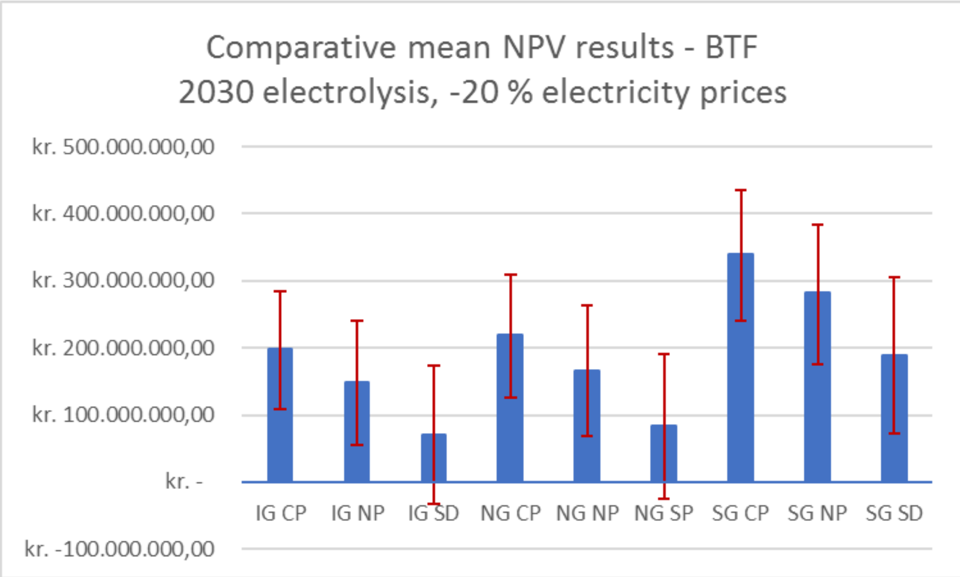

Figure 36 - Mean NPV results of hypothetical scenario, electrolysis at 2030 level, - 20 % electricity prices

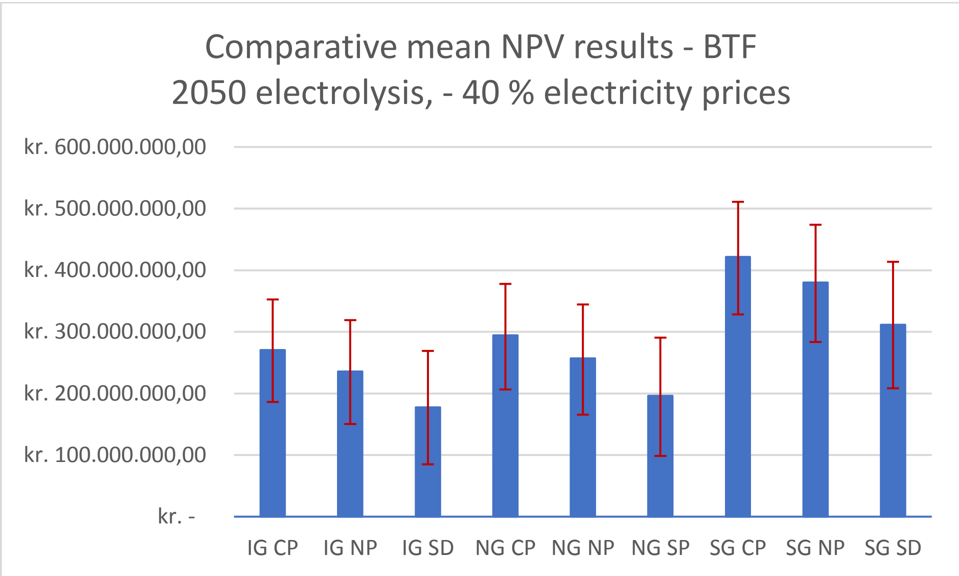

Figure 37- Mean NPV results of hypothetical scenario, electrolysis at 2050 level, - 40 % electricity prices

This would not increase the mean result of most scenarios above that of the HPWs alternative except in the most extreme examples, but it does raise the distribution of results into the same range, and even higher in some scenarios.

As substrates are a much greater part of the expenses of the HPWS alternatives, the BTF alternative could benefit from a situation where substrates were to increase in prices, for example if it became a limited resource. The price per GJ does differ from alternative to alternative, but the changes to NPV does not, as can be seen from Table 20.

Table 20 - Mean NPV of Normal Growth, New Policies, BTF - results of hypothetical scenarios with different substrate prices

Substrate Prices	- 40 %	- 20 %	+ 20 %	+ 40 %
BTF	DKK 101,843,601	DKK 72,550,928	DKK 13,965,103	DKK -15,327,358
HPWS	DKK 239,740,836	DKK 210,447,897	DKK 151,862,019	DKK 122,569,080

The LCA analysis can also benefit from such investigation. One hypothetical scenario that is of interest, is the potential for changes in technical lifetime – if the project end before or after it was expected. As can be seen from Figure 1, the impact of global warming per GJ is not expected to change – the differences, while they do exist, are too small to make a difference. The only noteworthy difference between the three lies in the margins of error for the 15-year case, whose distribution is skewed to the right – meaning the 95th percentile is much larger than would be expected.

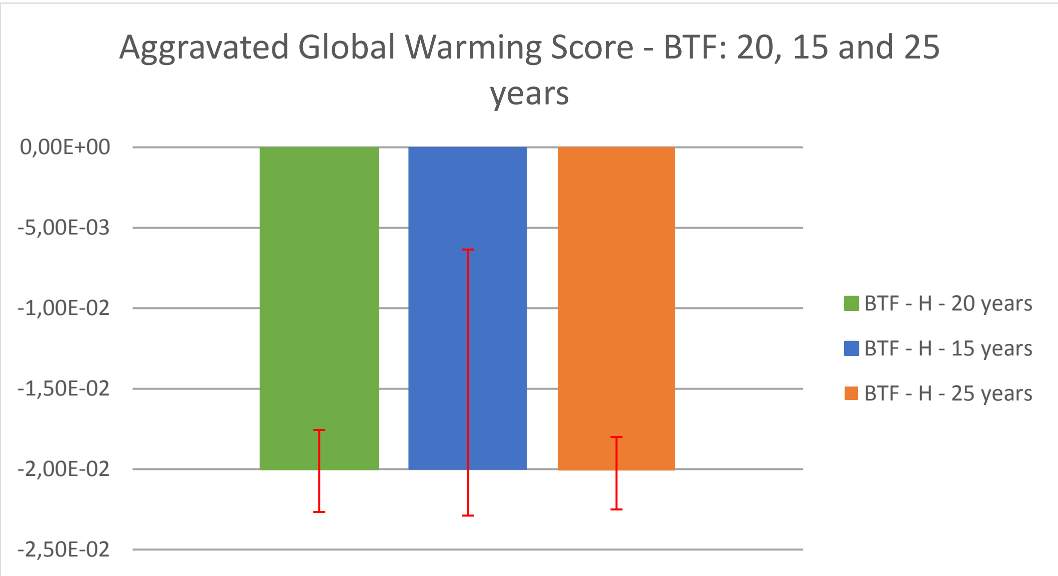

Figure 38 - Aggravated Score - Global Warming - BTF; 20-, 15- and 25-years technical lifetime, with 5th and 95th percentile acting as margins of error

The single score remains the same as it always is, utterly unchanging, still dominated by the fossil fuel scarcity impact, as seen by Figure 39.

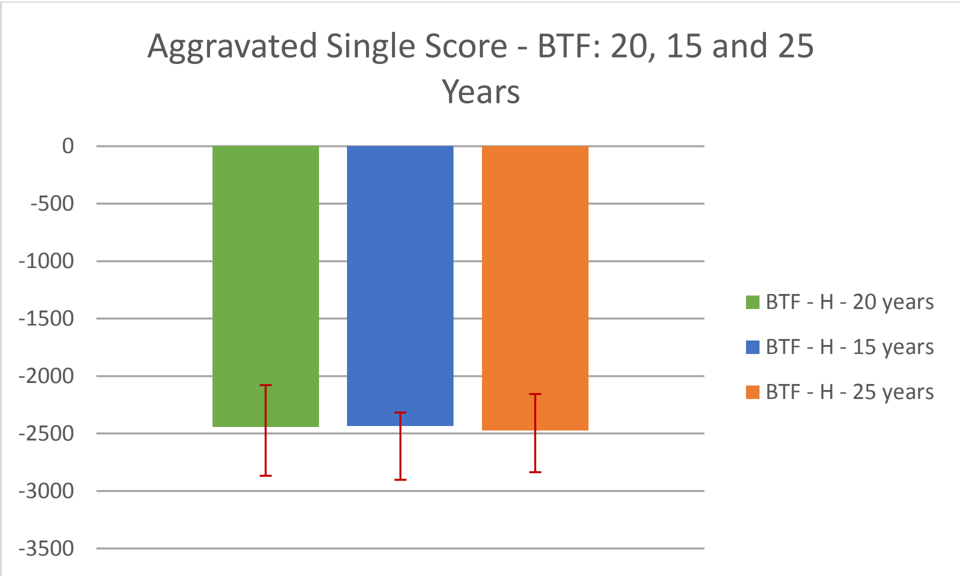

Figure 39- Aggravated Single Score - BTF; 20-, 15- and 25-years technical lifetime, with 5th and 95th percentile acting as margins of error

Discussion

LCC

This is the part the deals with the 7th of the 8 parts of the LCC, namely the discussion and comparison of results. First the results of the BTF will be discussed, then the HPWS and Chemical Absorption will be compared to it, and to each other. As with any other paper, it is important to note that the findings of this paper are only as true as the assumptions that it is built one. The discussion of the technology does not extent beyond scenarios that have been investigated.

When looking at the Figure 33 - Contribution Trees for the LCC, the electricity cost has largest contribution for the BTF alternative. This is almost entirely due to the hydrogen consumption. The fact that the hydrogen allows for a much greater biogas production – as the CO_2 is converted into methane rather than discarded – also means that the CAPEX, both for the AD plant and the upgrading technology represents a smaller cost relative to its whole.

As such, it comes as no surprise when Table 14 shows that the BTF alternative struggles in the Sustainable Development scenarios, where the electricity prices are the highest, and is stronger in the Current Policies scenarios, where the electricity prices are lower. Likewise, with the majority of expenses lying in the Operational phase, the BTF alternative fairs far better in the Scenarios where the interest rate is low, i.e. the Stagnation scenarios.

The scenario where the two are combined, namely the Stagnating Economy, Current Policies scenario is also the scenario BTF alternative is only the best performer in one of the nine scenarios. It should be pointed out however, that "best performer" in this paper, is assigned to the alternative where the distribution of its NPV results has the highest mean.

The fact that such a great portion of the expenses stem from the hydrogen consumption also helps explain the wide distribution of results that the BTF alternative has. The model assumes that the CO_2 content is a triangular distribution centered around 39.7 percent with its lower and upper limits at 30 and 50 % respectively. As CO_2 is directly tied to the biggest source of expenses, the electrolysis, as well as the only source of income, the production of BNG, this single uncertainty, more than any other factor, helps explain the wide distribution of results.

Figure 33 - Contribution Trees for the LCC also shows that the costs of the BTF is heavily reliant on the electricity cost at any given time, far more so than the alternatives. This can be seen when comparing the LCC results between the scenarios. Paradoxically the performances of the alternatives do not depend much on the natural gas prices. The natural gas price dependent part of the biogas tariffs ensures that even a significant price differential does not affect the NPV significantly.

While the Natural gas price does increase with inflation, the BTF alternative does not perform better in the scenarios with higher inflation. This is partially because prices of most other expenses also increase, but much more significantly because the CoE is greater. The NPV equation shows, that the higher the CoE is, the lower the NPV will be, and with CoE being dependent on the long-term interest rate (see Equation 3 – Definition of CoE), all alternatives perform worse, the higher the growth is. Since the scenarios with higher inflation will also has higher long-term interest rate, the investments do not perform better in these scenarios.

The BTF alternative shine and even potentially outperform the competitors, if electricity costs are reduced, as can be seen in Table 19 - Mean NPV results of BTF alternative in Normal Growth, New Policies scenario, in hypothetical scenarios - different electricity prices and electrolysis maturities. This could be achieved through the development of different electrolyser, or perhaps by investing into a greater electrolysis capacity. Hydrogen production could then exceed the consumption of the BTF alternative, allowing overproduction at times of low electricity prices, for consumption at times with high prices

Despite the fact that the substrate cost represents a comparatively larger percentage of costs for the other alternatives than for the BTF alternative, changes to the prices of said substrates affect the alternatives equally. The affect per GJ is different, but as the result of the LCC is a NPV, and the substrate intake is the same for all alternatives result in the same increase or decrease in costs across alternatives (see Table 20 - Mean NPV of Normal Growth, New Policies, BTF - results of hypothetical scenarios with different substrate prices)

HWPS and Chemical Absorber

The two established alternatives have very similar procurement costs, to the point where it has little effect on the final result. The main difference lies in the operational phase, in which two factors in particular are important: the methane leakage and the heat requirements.

The chemical absorber needs heat to regenerate its solvent. Its consequently lower biogas output is somewhat countered by its almost negligible methane loss. The HPWS on the other hand has a significantly higher methane loss, usually at 2 percent, compared to the 0.04 percent of the chemical absorber. The final thing that can affect the outcome, namely the technical availability, is almost the same in both cases.

Outside of this, as its Operational costs are relatively low and comparable, with the Chemical absorber haven slightly higher costs per Nm^3 due to the solvent consumption.

In either alternative, the scenarios have a much smaller impact on the final NPV, in great part because of the smaller contribution of electricity to the final result and the fact that natural gas prices do not affect the income substantially, as was mentioned above. Instead the Economic scenarios represents a greater difference, although not as much as for the BTF alternative as can be seen by comparing Figure 20 - Comparative results of NPV, BTF alternative, with blue indicating the mean, and red indicating the 5th and 95th percentiles Figure 20, Figure 21 and Figure 22

LCA

When it comes to the LCA results, the BTF alternative scored consistently better than the alternatives, except in the Individualist perspective, where its results overlapped with the Chemical Absorber.

The contribution tree for the global warming shows that the greatest advantage for the BTF alternative is its lack of CO_2 emission (see Figure 31). The other two strips it from the biogas, and then releases it into the atmosphere, while the BTF enriches it, and actually makes all other contributions per GJ smaller.

The electricity, which falls under the "Operation" category has a surprisingly small contribution, despite its large quantities. This can partially be attributed to the fact that the way ecoinvent model the Danish electricity market, but more importantly it is due to the vast contributions of the other aspects of production, the largest being the way substrates are being handled. Avoiding the methane emissions associated with the spreading of manure of the fields is a much more significant contribution, overshadowing the electricity consumption[19].

The BTF favorable score when compared to the two other alternatives. This is in great part due to its higher production capacity. A large part of the PFD is fixed, and does not change with production, namely the AD portion. With more GJs of gas being produced, the impact of the fixed AD components become significantly smaller.

Overall, all three alternatives are recommendable when compared to natural gas, outside o

Comparison to Similar Studies Found in Literature

In order to gauge the validity of the results in this paper, it is important to compare them to the results that other have gained. Due to the fact that this paper is based on a Danish private investor, Danish sources are more valuable for this comparison, but international sources will

[19] At the point of writing, it was discovered that the LCA results were erroneous, as the spreading and storage of digestate were modelled as being significantly smaller than they were supposed to. Due to the deadline being nonnegotiable, and the simulations being time consuming, there was not enough time to correct the mistake. The mistake did change the results of the LCA, but not the overall conclusion – the BTF still performed better than the alternatives in the global warming score, even more so, due to the impact of the digestate being "diluted" over more GJ of BNG, and the single aggravated score was still dominated by the avoided fossil fuel depletion

also be used. This partially due to the majority of literature being non-Danish, partially to investigate if the national perspective makes the results significantly different.

Seeing as the BTF alternative is a technology in development there is not much that can be compared to. It could potentially be compared to conventional BTF technologies, as these have been the basis for the components, however such a comparison could only be done in regard to the procurement costs, and even so, only sparingly.

The Danish Energy Agency has published a technology catalogue for renewable fuels, data from which has been used in this paper. Two figures which has not been used, were the Procurement cost estimate in that catalogue. The catalogue states that a typical plant in 2020 will have an 8.7 MW output, and an investment cost of 1.71 million 2015-Euro per MW. Accounting for inflation that results in ~115,875,000 DKK. This is somewhat higher than the cost estimated in this paper, but not to such an extent as to invalidate the results.

More specifically however, is the project description for Nature Energy Midfyn, the AD plant that forms the basis for the one modelled in this paper. According to its project description the AD plant itself had an estimated cost of 96.6 million DKK (Knudsen, 2013, s. 5) – which is within the result range of this paper.

The procurement costs for the HPWS and Chemical absorber were based on academic (Sun, et al., 2015) (Pierre, et al., 2017) (Muñoz, Meier, Diaz, & Jeison, 2015), so naturally they are in accordance with said. The aforementioned technology catalogue also includes costs for upgrading technologies

COWI also published a business case for an AD plant with upgrading technology – the conclusion of that case was a negative NPV (Laugesen, 2013). This difference can be explained by a difference in substrates, leading to the COWI case having a smaller methane yield.

For the LCA part of the analysis, LCA's on biogas production using the ReCiPe method do exist, though they are shorter in supply than other impact assessment. Even so, it is possible to compare this paper to literature. Literature does seem to agree, that biogas based on manure has a negative global warming impact[20]. One source estimates such biogas production to emit between minus 250 and minus 320 gram of CO_2 equivalents per MJ (Aikaterini K. Boulamanti*, 2013, s. 155). For comparison, when assessing the BTF alternative with the ReCiPe midpoint method[21], the most likely result was minus 65 grams per MJ of energy. This result does seem comparable, as the BTF alternatives was based on a mixture of straw and maize, as well as manure, which are not considered as "sustainable" as manure.

[20] It should be reiterated that in this context, a "negative" impact is good.
[21] This was done to get a climate change result in CO_2 kg equivalents, rather than the DALY, which ReCiPe endpoint uses

Conclusion

This final chapter will take care of the 8th and final part of the LCC, the conclusion on whether the BTF technology can be considered via and or competitive. The BTF alternative have several advantages, and it is possible for it to excel under certain circumstances.

Advantages

- The fact that BTF alternative has theoretically no methane loss is arguably its greatest advantage, leading to not only a reduced loss in income, but also a significantly lower climate change impact, when compared to the HPWS alternative.
- The BTF technology can lead to a much greater yield for the same substrate intake. For a prospective investor this can eliminate the need for an expansion of the AD part of a production plant.
- The environmental impact is the smallest of the three alternatives, in large part due to its greater production – leading to all fixed contributions to have a smaller impact per GJ – and because the CO_2 is enriched instead of being released into the atmosphere.

Opportunities

- The fact that hydrogen can be stored can lead to significant cost reductions, if this fact is taken advantage of, if the operator produces hydrogen in times of low electricity costs, i.e. when the wind is blowing and stores it for times of high electricity costs.
- If substrates become a limited resource, the BTF alternative has a great advantage over its competitors, due to a higher methane yield per ton substrate. This paper cannot show that this will lead to a higher NPV than its competitors, but the cost per GJ will be less affected.
- Literature indicates that electrolysis technologies will become cheaper, more efficient and have higher capacities with time, meaning that the BTF alternative is likely to become more efficient the later the investment is made.
- The literature indicates a clear trend that all biogas technology become cheaper with scaling. This is also the case with the BTF technology, as the secondary upgrading and the sweetening technologies will be dimensioned as a fraction of the production.

Conversely, the technology also has some clear drawbacks.

Disadvantages

- Due to its, as of yet, low methane purity, the addition of a secondary upgrading system is needed, as well as a sweetening technology and a steady hydrogen supply is needed. This complexity can potentially lead to an increase in downtime, which in turn reduces financial and environmental viability.
- The literature indicates that a small downtime will not hamper production significantly, but any breaks above a certain period of time will lead to a severe disruption in production capabilities – this is an issue the non-biological alternatives do not have.

- The high cost of electrolyser technology means that an investor needs that much greater up-front financing and securing capital could be a challenge for a smaller investor.

Threats

- Due to the fact that a great potion of the Operational costs is tied to the electricity price, the BTF alternative is more fragile when it comes to changes in said price. Not only does its competitors perform better in many scenarios, but they are also more robust, leading to a safer investment.
- The distributions of results are far more widely spaced than the competitors, meaning that the investment is riskier. This could dissuade a risk averse investor.

At this point, this paper concludes that under the assumptions that this paper is based on the BTF can be considered financially viable and environmentally competitive. It does also recommend, however, that more research is needed, especially as more accurate data becomes available.

Recommendations for Further Research

As mentioned in the literature review, an LCC is intended to be an iterative method. As a project develops, more information will become available, reducing the need for assumptions and increasing the accuracy of projections. This is especially the case for a technology in development, such as the BTF alternative. Recommended points of time for updated LCC's would be once each phase has ended, and before a new one begins – meaning after R&D has ended and before procurement and so forth.

Once R&D has finished, the LCC could for example be updated with the proper operating profiles, detailing the technical availability of the several different technologies having to work in conjunction with each other.

This paper is from the perspective of a prospective investor in the year 2020. It has not performed any calculations as to the socioeconomic costs. A Cost Benefit Analysis could potentially lead to an entirely different conclusion than the private LCC did, perhaps even providing an argument for public funding.

Likewise, if the year of investment was pushed to 2025 or even later, allowing for the electrolysis technologies to be further developed. This would in turn also lead to a greater uncertainty, as projections would have to be made even further into the future.

This paper has not investigated the financial advantages of the opportunity for hydrogen storage, which could prove to be its greatest advantage, but merely tried to emulate such a storage via a simple static scenario. This paper was not intended to be a production optimization – therefore an investigation into the balance between investments into electrolysis and hydrogen storage capacity versus electricity cost savings could potentially lead to interesting results.

One aspect that would likely change the results of both the LCC and LCA parts drastically would be to investigate plants at different production capacities – as cost and impact would likely change dramatically. This was not considered in this paper, because it was deemed to go beyond its scope.

As for the LCA part, this paper only considered four different substrates. It would be prudent to investigate the consequence of changing to different substrates, for example deep litter ("*dybstrøelse"* in Danish).

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Appendices

Appendix 1 – Cost Breakdown LCC – BTF

Table 21 - Table of cost incurring component in the Procurement Phase – BTF

The components needed for procurement has been based on Figure 12 and the original experiment (Dupnock & Deshusses, 2017).

Component	Source	Price
Gas inlet fan	[1]	72144 DKK 137859 DKK 171431 DKK (triangular)
Water Pump	[2]	287148 DKK 689357 DKK (uniform)
Reactor tank	[3]	2124083 DKK 4086599 DKK (uniform)
Packing Material	[4]	160706 DKK 702224 DKK (uniform)
Blower (hydrogen)	[5]	112738 DKK 489731 DKK (uniform)
Piping	[6]	6658.5 DKK 16650 DKK (uniform)
Chemical Absorber	[7]	5228525 DKK

		12752500 DKK 157167806 DKK (triangular)
Conventional BTF	8	1437460 DKK 2695237,5 DKK 3234285 DKK (triangular)
Electrolyser	9	55,406,621 DKK 83,109,317 DKK 110,812,423 DKK (triangular)
Heat Exchanger	10	222,862.33 DKK 755,561.59 DKK (uniform)
Natural gas connection station	11	53,797 DKK/MW 1,126,376 DKK total 207,504 DKK/MW 4,344,595 DKK total 345840 DKK/MW 7,240,992 DKK total (triangular)
Compressor[2]	12	10,000,000 DKK (deterministic)
Natural gas connection pipeline	13	300,000 DKK 2,650,000 DKK

	4,900,000 DKK (triangular)

1: The cost of the gas inlet fan was estimate by using the online tool *Matches* (Matches, 2019). The triangular distribution was created by estimating a blower of the "Turbo, small, 3 psi" type for the smaller estimate, a "rotary, 10 psi" type for the most likely estimate and a "Rotary, sliding vane" for the larger estimate, with a 588.56 ft^3 capacity, all on the 22nd of May 2019. The types were chosen based on which types could accommodate the chosen capacity. The capacity was chosen to accommodate a biogas flow of 1000 m^3/h, which was the assumed biogas flow at that point in time.

2: The cost of the water pump was estimate by using the online tool *Matches* (Matches, 2019). The uniform distribution was created by estimating the cost of a pump of the "Diaphram, Simplex, Large" type, of stainless steel with a packing seal with a flowrate of 70 gallons/minute for the smaller estimate, and a pump of the "diaphragm, simplex, Large" type, made of stainless steel 316 and with a double mechanical seal with a flowrate of 140 gallons/minute, both on the 22nd of May 2019. The pump type was chosen on the basis that they were industrial pumps that could handle the flowrates. The flowrates were chosen as they equated to a water flowrate of 15.83-31.95 m^3/h, which is what the BTF has been estimated to use.

3: The cost of the reactor tank was estimate using the online tool *Matches* (Matches, 2019). The uniform distribution was created by estimating the cost of a 158503 gallon vertical, cone roof, flat bottom, field fabricated tank of stainless steel for the smaller estimate and a 237754 gallon vertical, cone roof, flat bottom, field fabricated tank made of stainless steel 16 for the larger estimate, both on the 20th of April 2019. The capacities were chosen to equal 600-900 m^3, which is the necessary estimated reactor size.

4: The cost packing material, polyurethane foam, has an estimated price of 7190 and 8378 USD/ton (Plastics Insight, 2019). The packing material has been estimated to fill between 80 and 100 percent of the reactor space, which has an estimate 600-900 m^3 volume, and the foam has an estimated density of 7-14 kg/m^3. The lower estimate was made by assuming the lower number for each variable, and the higher estimate was made using the higher number for each estimate.

5: The cost of the blower was estimated using the online tool *Matches* (Matches, 2019). The uniform distribution was created by estimating an axial, large, 1 atm, 0.5 atm vacuum blower for the smaller estimate and a turbo, 10 psi blower for the larger estimate, both for a 2,043 ft^3/min blower capacity on the 20th of April 2019.

6: The cost of the piping was estimated using a meter price of using meter price provided by a Danish manufacturer, whose price for steel pipes is 133.17 DKK/m for bulk sales, and 166,5 for individual sale (Stålxperten, 2019). Assuming 50-100 meters of piping.

7: The cost of the chemical absorber was estimated using the same data as for the Chemical Absorption alternative. The capacity of the chemical absorber was assumed to be one tenth of the BTF, in order to accommodate for the 10 percent remaining CO_2, resulting in a necessary capacity of approximately 205 m^3/h. Most data do not accommodate for a absorber that small – the lowest capacity which the Swedish Gas Center includes in their report was 500 m^3/h (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 21). One source report includes costs for a 100 m^3/h absorber, which costed 73989.30 DKK/m^3 h^{-1} (Sun, et al., 2015, s. 527). This forms the basis for the largest cost estimate. The smaller estimate is based on the Swedish 500 m^3/h figure, being approximately 25505 DKK/m^3 h^{-1}, on the theory that this cost could perhaps be transferred to smaller capacities as well. The most likely estimate is based on a 500 m^3/h absorber, using the SGC 500 DKK/m^3 h^{-1} price as well, on the theory that this is the smallest absorber that will be available.

8: The cost of the conventional BTF was estimated using data from a Danish report on H_2S in biogas (Eliasen & Kvist, 2015, s. 27-29). The necessary capacity of the conventional BTF has been estimated at 205 m^3/h. The report details the cost of 3 different suppliers of "biological filters" for biogas sweetening, with one provider estimating the cost as 0,075 DKK/Nm^3 for 200 m^3/h, another estimating 0.09 DKK and the third 0.04 DKK. These three forms the basis for the most likely, higher and lower estimate.

9: The cost of the electrolyser is based on data from the Danish technology catalogue for renewable fuels (Energinet, 2017, s. 111). According to it, the chosen type of electrolyser (an alkaline electrolyser) can be expected to cost 600,000 2015 Euro/MWe in 2020, with an upper and lower uncertainty of 400,000 and 800,000 Euros respectively. The necessary capacity has been estimated as 17.8 MW

10: The cost of the heat exchanger is based on the method provided in a lecture from the university of Pennsylvania (Seider, 2019). The low estimate was based on an assumption of a fixed head, carbon steel shell, stainless steel tube, a tube length of 20 feet, a pressure of 100 psi, and an area of 376.73 $feet^2$, resulting in a price of 222,862.33. The high estimate was based on a floating head, stainless steel shell, stainless steel tube, a tube length of 8 feet, a pressure of 450 psi and an area of 430.55 ft^2, resulting in a cost of 775,561.59 DKK.

11: According to the technology catalogue for energy transmission (Energinet, 2017, s. 63), a monitoring station costs 207478,31 DKK per MW, with 53790,653336 and 345797,174387 being the lower and upper uncertainties. Assuming the substrates yield 11.7 million m^3 CH_4 year, with a 40 percent CO_2 concentration and a energy density of BNG of 40.34, this equals

$$11{,}700{,}000\frac{m_{CH_4}^3}{year} * 1.4 * 40.34\frac{MJ}{m^3} = 660{,}769{,}200\frac{MJ}{year} = 20.94\,MW$$

12: the technology catalogue includes data for a natural gas monitoring station, but not for a connection station – meaning one that can compress the BNG to the necessary pressure. To accommodate this, this paper assumes that the price is equal to the monitoring station, plus a

10 mio DKK compressor, which is the price stated in a business case from COWI (Laugesen, 2013)

13: Modelled in accordance with Danish project descriptions (Dansk Gas Distribution A/S, 2018, pp. 4-5) (SEGES, 2017, p. 21), assuming a length of 1 – 5 – 7 kilometers, as a triangular distribtution.

Table 22 - Table of cost incurring elements in the Operation Phase - BTF

Component	Source	Amount
Mineral Medium (per m^3)	(Deshusses & Webster, 2000)	5.73E-03 DKK 1.72E-02 DKK 4.12E-02 DKK (triangular)
Electricity (electrolysis) (1 m^3)	1	Electricit price dependent on scenario
Electricity (water pump) (1 hour)	See assumptions section	1.39 kWh 2.89 kWh with electricity price being dependent on scenario (deterministic)
Water (1 hour)		1.5 m^3, with water price being Mean: 15.31 DKK SD: 2.56 DKK (normal)
Maintenance (1 year)		2 % of procurement costs 3 % of procurement costs 4 % of procurement costs (triangular)

1: Electricity consumption=0.42-0.65-.81 $\left[\frac{m^3_{CO_2}}{m^3_{CH_4}}\right]$ (triangular)*4 $\left[\frac{m^3_{H_2}}{m^3_{CO2}}\right]$*0.0899 $\left[\frac{kg_{H_2}}{m^3_{H_2}}\right]$*51.23-59.67 kWh/kg H2 (uniform)

Table 23 - Table of Resale Values - BTF

Component	Lifetime	Resale value as percentage of procurement cost
BTF	20	0 %
Natural Gas line	50	60 %
Compressor	50	60 %
Natural gas station	50	60 %

Appendix 2 – Cost Breakdown LCC – HPWS

Table 24 - Table of cost incurring component in the Procurement Phase - HPWS

Component	Source	Price
Upgrading plant, in its entirety[1]	(Sun, et al., 2015) (Muñoz, Meier, Diaz, & Jeison, 2015) (Muñoz, Meier, Diaz, & Jeison, 2015)	11751.54 DKK/m^{3} $^{h-1}$: 15864579 DKK 12731.44 DKK/m^{3} $^{h-1}$: 17187444 DKK 14146.03 DKK/m^{3} $^{h-1}$: 19097140 DKK (triangular)
Natural gas connection station[2]	(Energinet, 2017, s. 63)	53,797 DKK/MW 806,955 DKK Total 207,504 DKK/MW

		3,112,560 DKK Total 345840 DKK/MW 5,187,600 DKK Total (triangular)
Compressor[2]	(Laugesen, 2013)	10,000,000 DKK
Natural gas connection pipeline	(Dansk Gas Distribution A/S, 2018, pp. 4-5) (SEGES, 2017, p. 21).	300,000 DKK 2,650,000 DKK 4,900,000 DKK (triangular)

1: The procurement of the HPWS alternative has been estimated with the parametric method, using sources found during the literature review. The parameter is DKK per upgraded m^3 of biogas per hour. Assuming a yearly methane yield of 11.7 mio m^3, this results in 1334 m^3 h^{-1} (rounded up to 1350).

2: Estimated in the same way as the BTF alternative, except with a 15 MW capacity.

Table 25 - Table of cost incurring elements in the Operation Phase - HPWS

Component	Amount	Price
Water	2 – 3 m^3 (uniform)	Based on (normal distribution)
Electricity	0.17-0.22.042 (triangular)	In accordance to scenario
Maintenance	2 – 3 - percent	Of Procurement costs

Table 26 - Table of Resale Values - HPWS

Component	Lifetime	Resale value as percentage of procurement cost
HPWS	20	0 %
Natural Gas line	50	60 %

Compressor	50	60 %
Natural gas station	50	60 %

Appendix 3 – Cost Breakdown LCC – Chemical Absorption

Table 27 - Table of cost incurring component in the Procurement Phase - Chemical Absorption

Component	Source	Price
Upgrading plant, in its entirety[1]	(Sun, et al., 2015) (Sun, et al., 2015) (Pierre, et al., 2017)	16186.89 DKK/m^3 h^{-1} 21852301 DKK 24284.44 DKK/m^3 h^{-1} 32783994 DKK 35116.13 DKK/m^3 h^{-1} 47406784 DKK (triangular)
Natural gas connection station[2]	(Energinet, 2017, s. 63)	792424.17 DKK 3051340.31 DKK 5085567.18 DKK (triangular)
Compressor	(Laugesen, 2013)	10,000,000 DKK (deterministic)
Natural gas connection pipeline	(Dansk Gas Distribution A/S, 2018, pp. 4-5) (SEGES, 2017, p. 21).	300,000 DKK 2,650,000 DKK 4,900,000 DKK (triangular)

1: Estimated in the same manner as the HPWS alternative.

2: Estimated in the same manner as the HPWS alternative.

Table 28 - Table of cost incurring elements in the Operation Phase - Chemical Absorption

Component	Source	Amount
Water (per m^3)	(Bauer, Hulteberg, Persson, & Tamm, 2013, s. 51)	3.0E-05 m^3
Chemical Solvent (per m^3)	(Bauer, Hulteberg, Persson, & Tamm, 2013, s. 51)	3.0E-05 m^3
Electricity (per m^3)	(source patterson)	0.12 kWh

		0.15 kWh 0.646 kWh (triangular)
Maintenance (%)	(Bauer, Hulteberg, Persson, & Tamm, 2013)	2 % 3 % 4 % (triangular)
Heat Consumption (per m^3)	(Angelidaki) (Angelidaki, 2018) (Bauer, Hulteberg, Persson, & Tamm, 2013, s. 51) (Angelidaki, 2018, s. 545)	0.5 kWh 0.55 kWh 0.75 kWh (triangular) with electricity price being dependent on scenario

Table 29 - Table of Resale values - Chemical Absorption

Component	Lifetime	Resale value as percentage of procurement cost
HPWS	20	0 %
Natural Gas line	50	60 %
Compressor	50	60 %
Natural gas station	50	60 %

Appendix 4 – Cost Breakdown LCC - AD

Table 30 - Table of cost incurring component in the Procurement Phase – AD

The cost breakdown is based on Nature Energy Midtfyn, a funen based AD plant with a substrate intake of 360,000 tons a year (Henriksen, 2015).

Component	Source	Cost
Land Purchase (78,464 m^2)	(Schjerning & Jens, 2019)[1]	141,000 DKK/ha 11,063,424 DKK 150,000 DKK/ha 11,769,600 DKK 158,000 DKK/ha 12,397,312 DKK (triangle)
Trucks (6)	(Jacobsen, Laugesen, Dubgaard, & Bojesen, 2019, s. 69 & 80)	2,000,000 per truck, 12,000,000 total (deterministic)
Reception hall (360 m^2)	(Rasmussen, 2019) (Stålhaller.dk, 2019) (HPH Totalbyg, 2019)	330 DKK/m^2 118,800 DKK total 1085 DKK/m^2 390,600 DKK total 1950 DKK/m^2 702,000 DKK total (triangular)
Hall for solid biomass (720 m^2)	(Rasmussen, 2019) (Stålhaller.dk, 2019) (HPH Totalbyg, 2019)	330 DKK/m^2 237,600 DKK total 1085 DKK/m^2 781,200 DKK total 1950 DKK/m^2

		1,404,000 DKK total (triangular)
Personel Building (165 m^2)	(Birk-Dahl Erhvervsbyggeri A/S, 2019)	5500 DKK/m^2, 907500 DKK total (deterministic)
Technical Building (200 m^2)	(Rasmussen, 2019) (Stålhaller.dk, 2019) (HPH Totalbyg, 2019)	330 DKK/m^2 66,000 DKK total 1085 DKK/m^2 217,000 DKK total 1950 DKK/m^2 390,000 DKK total (triangular)
Silo for energy crops (25,000 m^3, "*plansilo*")	(Jensen & Gjødesen, 2019, s. 16)	225 DKK/m^3 5,625,000 DKK total 350 DKK/m^3 8,750,000 DKK total (uniform)
Boiler (2.5 MW)	(Wit & de, 2016, s. 14) [2]	1.5 million DKK/MW 3,750,000 DKK total 3 million DKK/MW 7,500,000 DKK/total (uniform)
Heat Exchangers	[3]	222862 DKK 755561 DKK (uniform)
1st Reception tank (700 m^3)	(Tind, 2019)	125 DKK/m^3

		87,500 DKK total 150 DKK/m^3 105,000 DKK total (uniform)
2nd Reception tank (3000 m^3)	(Tind, 2019)	125 DKK/m^3 375,000 DKK total 150 DKK/m^3 450,000 DKK total (uniform)
Sanitation tanks (2 a 20 m^3)	(State of Michigan, 2019, s. 4)	696,762 DKK/tank 771,658 DKK/tank (uniform)
Mixing tank (160 m^3)	[4]	391,354 DKK 1,329,886 DKK (uniform)
AD Tanks (3 a 8500 m^3)	[5]	5,173,056 DKK/piece 17,587,959 DKK/piece (uniform)
Gas storage/digestate tank (3000 m^3)	(Tind, 2019)	125 DKK/m^3 375,000 DKK total 150 DKK/m^3 450,000 total (uniform)
Piping (2486.7 m)	(Oldebjerg A/S, 2019)[6]	70.93 DKK/m 176381 DKK total

	(Oldebjerg A/S, 2019) (Bygma A/S, 2019)	73.925 DKK/m 183829 DKK total 158.35 DKK/m 393768 DKK total
Torch	(Caine, 2019, s. 9)	1,025,314 1,904,156 DKK (uniform)
VVS and electrical connections	(Dansk Gas Center, 2019, s. 3)	1,600,000 DKK 2,100,000 DKK (uniform)
Installation costs		+ 25 %

1: distribution is based on the lowest and highest price in the last two years, while the most likely was based on the average.

2: The source actually states the estimated cost of an electrical heat pump, not that of a boiler – however this was discovered after the monte carlo simulation had run. A choice was made to leave the error as it were, rather than run the 8 hour simulation again.

3: Estimated in the same manner as with the BTF alternative.

4: The cost of the AD tanks was estimated using online tool matches (Matches, 2019). The uniform distribution was created by estimating a vertical, cone roofed field fabricated tank with a flat bottom, made from carbon steel for atmospheric pressure for the low estimate and a vertical, cone roofed field fabricated tank with a flat bottom, made from stainless steel 316 for atmospheric pressure for the high estimate, both on the 12th of march, 2019.

5: The cost of the AD tanks was estimated using online tool matches (Matches, 2019). The uniform distribution was created by estimating a vertical, cone roofed field fabricated tank with a flat bottom, made from carbon steel for atmospheric pressure for the low estimate and a vertical, cone roofed field fabricated tank with a flat bottom, made from stainless steel 316 for atmospheric pressure for the high estimate, both on the 13th of march, 2019.

6: Lowest and most likely estimate both come from (Oldebjerg A/S, 2019).

Table 31 - Table of cost incurring elements in the Operation Phase - AD

Component	Source	Amount
Slurry, cow manure	(Birkmose, Hjort-Gregersen, & Kasper, Biomasse til biogasanlæg i Danmark - på kort og langt sigt, 2019, s. 3)	350 DKK/ton
Slurry, pig manure	(Birkmose, Hjort-Gregersen, & Kasper, Biomasse til biogasanlæg i Danmark - på kort og langt sigt, 2019, s. 3)	350 DKK/ton
Straw	(Birkmose, Hjort-Gregersen, & Kasper, Biomasse til biogasanlæg i Danmark - på kort og langt sigt, 2019, s. 3)	590 DKK/ton
Maize		867 DKK/ton
Labor (6 fulltime laborers)		M: 614,000/man/year SD:154,000 (normal)
Electricity	(Energinet, 2019, s. 34)	4.3 kWh/ton input 8 kWh/ton input 14 kWh/ton input (triangular) With electricity price being dependent on scenario
Insurance and administration		1,000,000 DKK/year
Maintenance		2 % of procurement cost 3 % of procurement cost 4 % of procurement cost (triangular)

Table 32 - Table of resale values - AD

	Technical Lifetime	Resale value
AD plant	20 years	0 %
Land Purchase	n/a	100 %

Appendix 5 – LCA inventory – BTF

Table 33 - LCA inventory, procurement phase – BTF

The inventory has partially been based on Figure 11 and the original experiment (Dupnock & Deshusses, 2017).

Component	Flow	Amount
Amine Scrubber[1]	Manufacture (ecoinvent – steel, low-alloyed) Condenser Cooler Heat Exchanger Pump	23,000 kg 1 1 1 1 (deterministic)
Blower	Manufacture (ecoinvent – air compressor, screw-type compressor, 4 kW)	1 (deterministic)
BTF for biogas sweetening[2]	Manufacture (ecoinvent – steel, low-alloyed)	9470 kg (deterministic)
Electrolyser[3]	Manufacture (stainless steel)	3343 kg (deterministic)
Gas inlet Fan	Manufacture (ecoinvent – acir compressor, screw-type compressor, 4 kW)	1 (deterministic)
Heat exchanger	Manufacture (ecoinvent – blower and heat exchange unit, decentralized, 180-250 m^3/h)	1 (deterministic)
Packing material[1]	Manufacture (ecoinvent – polyurethane, rigid foam)	480 m^3 900 m^3 * 7 kg/m^3

		14 kg/m^3 (uniform)
Piping	Manufacture (ecoinvent – chromium steel pipe)	4571.61 kg 13714.85 kg (uniform)
Pump	Manufacture (ecoinvent – pump, 40W)	1 (deterministic)
Reactor Tank[2]	Manufacture (ecoinvent – steel, low-alloyed)	29,200 kg 34,700 kg (uniform)

1: Is assumed to consist of a condenser, cooler, heat exchanger and pump, modelled the same as in the case of the chemical absorber alternative. Also consists of an absorption and stripper tower, each weighing 11,500 kg.

2: The BTF and the conventional BTF are assumed to “share” much of the components needed, as such the only component modeled here is the reactor tank, modeled here as a 100 m^3 steel tank, weighing 9.47 tons (SOURCE).

1: The original experiment specifies that the packing material in the test reactor was polyurethane foam, but does not specify the density, merely that it was “open cell” (SOURCE). The density is assumed to be between 7 and 14 kg/m^3, in accordance with open pore foam (Purios, 2019). The material is assumed to take up between 80 and 100 percent of the reactor volume – in the original experiment, the test reactor was filled entirely.

2: According to Dupkneck and Deshusses, the reactor can process 90 m^3 of biogas per m^3 of reactor per day. Assuming 11.8 million m^3 of methane a year, with a CO_2 content of 40 %, or ~54000 m^3 of biogas day, this equates to

$$\frac{\sim 54{,}000\ m^3}{90\,\frac{m^3}{m^3}} = \sim 600\ m^3$$

600 m^3 of rector volume, or 900 if the reactor is over dimensioned by 1.5, in order to handle inconsistencies in production flow. These particular sizes could not be found amongst producer, but according to a producer, a 700 m^3 steel tank weighs 29.2 tons of steel and a 1000 m^3 steel tanks weighs 34.7 tons (Russian Tank Works, 2019).

The operational phase of upgrading is divided into several steps. First the biogas is produced, after which some is burned in the torch – this is determined by the technical availability of the upgrading technology. Then some is burned in the boiler – this is determined by the heat requirements of the AD plant and upgrading technology. Then some is lost during the upgrading process itself – this is determined by the leakage. To differentiate between the different stages, the biogas amount is described as post torch, post boiler and post leakage.

3: The electrolyser has been modelled in accordance with the inventory of life cycle assessment of a "High temperature" electrolyser (Patyka, Bachmann, & Brisse, 2013, s. 3870). The inventory also includes Nickel Oxide, "Yttrium-stabilized zirconia" and "Lanthanum strontium manganite", none of which are included in the ecoinvent database, hence their exclusion.

Table 34 - LCA inventory, operational phase - BTF

Component	Flow	Amount
Electricity (electrolysis) (1 m^3)[1]	Electricity (wind, >3MW turbine, onshore, consequential) *CO_2 content*Hydrogen to Methane ration*Electrolysis Power consumption*Hydrogen density	0.42 0.65 0.81 (triangular) * 4 * 0.0899 * 51.23 59.67 (uniform)
Electricity (pumps) (1 hour)[2]	Electricity (ecoinvent – market for electricity, low voltage, consequential, Denmark)	1.43 kWh 2.89 kWh uniform
Mineral Medium (1 m^3)[3]	Manufacture (ecoinvent – nitrogen fertilizer, as N) (ecoinvent – phosphate fertilizer, as P2O5)	 0.7 g 1.2 g

	(ecoinvent – potassium fertilizer, as K2O)	0.8 g
Water (1 hour)[4]	Water supply (ecoinvent – tap water)	1.583 m^3 3.195 m^3 (uniform) * 997 kg/m^3
Maintenance (1 year)	Procurement phase components	2.5 % 3 % 3.5 % (triangular)
CO_2 (1 m^3)	Emission to air (carbon dioxide) * CO_2 content per m^3 CH_4.	1.847 kg * 0.42 0.65 0.81 (triangular)
Methane Leakage (1 m^3 post boiler)	Emission to air (methane) * leakage	0.668 kg * 0 0.001 (uniform)
Avoided Natural gas production (1 m^3 post leakage)	Manufacture (ecoinvent – natural gas, low pressure)	1 m^3
Avoided Natural gas combustion at CHP (1 m^3 post leakage)	Emission to air (Carbon dioxide) (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides)	 1.92222 kg 0.00024 kg 1.02518 E-5 kg 0.00027 kg

	(Particuates, > 10 um) (Sulfur dioxide)	0.00019 kg 9.61108 E-6 kg
BNG combustion at CHP (1 m^3 post leakage)	Emission to air (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides) (Particuates, > 10 um) (Sulfur dioxide)	 0.00024 kg 1.02518 E-5 kg 0.00027 kg 0.00019 kg 9.61108 E-6 kg

1: Depending on the CO_2 content of the biogas, each m^3 of methane will be accompanied by e 0.42-0.65-0.81 (triangular) m^3 of CO_2, with each m^3 of CO_2 requiring four times that amount of H_2 (SOURCE DEshusses). The H_2 is produced via electrolysis, which have a power requirement of 51.23-59.67 (uniform) kwh/kg h_2 (SOURCE katalog) and hydrogen has a density of 0.0899 kg/m^3 (SOURCE).

2: the work of the pumps is estimate using the following formula

$$P\mathrm{h}(\mathrm{kW}) = \frac{q * \rho * g * h}{3.6 * 106 * \eta}$$

Where q is the flow capacity $\left[\frac{m^3}{h}\right]$, ρ is the density of the fluid $\left[\frac{kg}{m^3}\right]$, g is the gravitational acceleration $\left[\frac{m}{s^2}\right]$, h is the height $[m]$ and eta is the efficiency of the pump $[-]$. Assuming an efficiency of 0.6, water having a density of 997 kg m^{-3} and the btf tower being 20 meters, the pump work can be estimated to

$$BTF_{pump\ work} = \frac{15.83 - 31.95(uniform) * 997 * 9.81 * 20}{3.6 * 10^6 * 0.6} = 1.43 - 2.89\ kW\ (uniform)$$

3: the original experiment used a specific mineral medium – initial investigation into its manufacture suggest that it would be far too expensive and labor intensive to use for a plant scale reactor. Instead, this paper assumes that the minerals consumed are comparable to that of a conventional BTF (Deshusses & Webster, 2000, s. 1954)..

4: The water flow for a conventional BTF is recommended as “1.1-1.7 times the minimum”, which is ~20 gallons per ft^2 of cross sectional area per hour, or $\sim 0.374 \frac{m^3_{water}}{m^2_{reactor}}$ per hour (Oliver & Gooch, 2016, s. 1). Assuming that the tank is approximately 4.5 times as tall as it is wide, the cross-sectional area will be 38.48 m^2 for the 600 m^2 tank and 50.26 m^2 for the 900 m^3 tank[22]. This results in a water consumption of somewhere between $1.1 * 0.374 \frac{m^3}{m^2} * 38.48\ m^2 = 15.83\ m^3$ and $1.7 * 0.374 \frac{m^3}{m^2} * 50.26\ m^2 = 31.95\ m^3$ an hour. The water can likely be reused, but no source has been found that clarifies how much. As such, this paper assumes that approximately 90 percent can be reused, resulting in a water consumption between $15.83 \frac{m^3}{h} * 0.1 = 1.583 \frac{m^3}{h}$ and $31.95 \frac{m^3}{h} * 0.1 = 3.195 \frac{m^3}{h}$. The remaining ten percent is assumed to be lost due to vaporization, consumption by the microorganisms, leakages etc.

Table 35 - LCA inventory, end-of-life phase - BTF

Component	Flow	Amount
Scrap steel, from BTF	Waste treatment (ecoinvent – scrap steel)	34071.61 – 48414.85 kg (uniform)
Waste Pulyurethane foam, from packing material	Waste treatment (ecoinvent – waste polyurethane foam)	3,360 – 12,600 kg
Scrap steel, from chemical absorber	Waste treatment (ecoinvent – scrap steel)	23,000 kg

[22] A 600 m^3 tank with a diameter of 3.5 meter will results in a cross-sectional area of $(3.5\ m)^2 * \pi = 38.48\ m^2$ and a height of 15.59 m, making it 4,45 times taller than it is wide. A 900 m^3 tank with a diameter of 4 m will results in a cross-sectional area of $(4\ m)^2 * \pi = 50.26\ m^2$ and a height of 17.90 m, making it 4.47 times taller than it is wide.

Appendix 6 – LCA inventory – HPWS

The inventory has been partially based on Figure 13 and Figure 14

Component	Flow	Amount
Absorption Tower [1]	Manufacture (ecoinvent – steel, low-alloyed)	12,800-16,600 kg (uniform)
Carbon Filtre	Manufacture (ecoinvent – air filter, decentralized unit, 180-250 m3/h)	1
Compressor	Manufacture (ecoinvent – air compressor, screw-type compressor, 300kW	1
Drier [2]	Manufacture (ecoinvent – steel, low-alloyed)	520-780 kg (uniform)
Flash Tower [1]	Manufacture (ecoinvent – steel, low-alloyed)	7441-9500 kg (uniform)
Inlet Seperator	Manufacture (ecoinvent – supply air inlet, steel/SS, DN 75)	1
Stripper Tower [1]	Manufacture (ecoinvent – steel, low-alloyed)	12,800-16,600 kg (uniform)
Water Pump	Manufacture (ecoinvent – pump, 40W)	1

1: https://www.fmk.dk/fileadmin/user_upload/By_Land_og_Kultur/Lervangsvej_2__5672_Broby_-_Milj%C3%B8godkendelse_2015.pdf claims that it that the entire scrubber has a storage volume of 510 m^3. Assuming that the absorption and stripper tower are of equal size, with the flash tower being roughly a fourth of that size – in a 45:45:10 ration – the towers have a volume of 229.5:229.5:51 m^3. (Russian Tank Works, 2019)states that a 200 m^3 tank weighs 12.8 tons and a 300 m^3 weighs 16.6 tons.

A 51 m^3 could be 12 m tall and have an internal diameter of 1.163 m. If the thickness is 7.5 mm, the weight of the tank is

$$m = \pi * (r_{outer}^2 - r_{inner}^2) * h * \rho = \pi * (1.6385^2 - 1.6310^2) * 12 * 8050) = 7441.42$$

While Russian tankworks states that the smallest tank they have weighs 9.5 tons (Russian Tank Works, 2019)

2: A provider of gas dryers, specifically for biogas use, claims that their largest biogas dryer is made of stainless steel and weighs 650 kg (Dominick Hunter, 2019, s. 2). A 20 percent margin of error has been added.

Table 36 - Table of Operational Inventory - HPWS alternative. Component are either listed as the consumption per year, consumption per day or consumption per m^3 of upgraded biogas. Triangular ditributions are noted as lower-most likely-upper, uniform distributions are noted as lower-upper.

Component	Flow	Amount
Maintenance (1 year)	Procurement phase components	0.025 0.03 0.035 (triangular)
CO_2 (1 m^3)	Emission to air (carbon dioxide)	0.42 0.65 0.81 (triangular) * 1.847 kg
Methane Leakage (1 m^3)	Emission to air (methane)	0.01 0.02 0.047 (triangular) * 0.668 kg
Electricity Usage (1 m^3)	Electricity (ecoinvent – market for electricity, low voltage, consequential, Denmark)	0.21 0.23 (uniform)

Water Usage (1 day)	Water supply (ecoinvent – tap water)	2 m^3 3 m^3 (uniform)
Avoided Natural gas production (1 m^3)	Manufacture (ecoinvent – natural gas, low pressure)	1 m^3 (deterministic)
Avoided Natural gas combustion at CHP (1 m^3)[1]	Emission to air (Carbon dioxide) (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides) (Particuates, > 10 um) (Sulfur dioxide)	 1.92222 kg 0.00024 kg 1.02518 E-5 kg 0.00027 kg 0.00019 kg 9.61108 E-6 kg (deterministic)
BNG combustion at CHP (1 m^3)[1]	Emission to air (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides) (Particuates, > 10 um) (Sulfur dioxide)	 0.00024 kg 1.02518 E-5 kg 0.00027 kg 0.00019 kg 9.61108 E-6 kg (deterministic)

1: The combustion of Bio-natural-gas is assumed to have the same emissions as natural gas. The emissions are based on data from the American Environmental Protection Agency (U.S. E.P.A., 2016). The carbon dioxide from BNG combustion is assumed to be recaptured in biomass, hence its omission.

Table 37 - LCA inventory, end-of-life phase - HPWS

Component	Flow	Amount

Steel[1]	Waste treatment (ecoinvent – scrap steel)	33561 kg 43480 kg (uniform)

1: The steel being recycled is eual to the amount of steel used in the construction of the works. The recycling smaller components have not been modelled, due to a lack of representative ecoinvent data.

Appendix 7 – LCA inventory – Chemical Absorption

Table 38 - LCA inventory, procurement phase - Chemical Absorption

The construction of the chemical absorber has partially been based on Figure 16.

Component	Flow	Amount
Abosrption Tower[1]	Manufacture (ecoinvent – steel, low-alloyed)	9500.0 kg 11493.13 kg (uniform)
Condenser[2]	Manufacture (ecoinvent – copper) (ecoinvent – steel, low-alloyed)	103.75 kg 311.25 kg (uniform)
Cooler	Manufacture (ecoinvent – steel, low alloyed)	415 kg (deterministic)
Heat Exchanger	Manufacture (ecoinvent – blower and heat exchange unit, decentralized, 180-250 m^3/h)	1 (deterministic)
Pump	Manufacture (ecoinvent – pump, 40W)	1 (deterministic)
Stripper Tower[1]	Manufacture (ecoinvent – steel, low-alloyed)	9500.0 kg 11493.13 kg (uniform)

1: According to (Ochienga, Berrouk, Peters, & Slagle, 2019, s. 6) one absorption tower had a "packing height 15.24 m, and a diameter of 2.972 m. Assuming a 10 mm thickness, and that the stripper tower is of equal size. That gives it an inner volume of roughly 100 m^3

$$Volume_{tower} = 1.486^2 * \pi * 15.24 = 105.72\ m^3$$

A similar sized steel tank weighs 9.5 tons=9500 kg (Russian Tank Works, 2019).

Assuming a 10 mm thickness, and that the stripper tower is of equal size:

$$Mass_{tower} = (1.496m^2 - 1486^{m2}) * \pi * 15.24\ m * 8050 \frac{kg}{m^3} = 11493.13\ kg$$

2: According to the Airedale condenser technical manual, their CR165 condenser (their largest) weighs 415 kg and is made of galvanized sheet steel and rifled copper tubes. Assuming a 75:25 ratio.

Table 39 - LCA inventory, operational phase - Chemical Absorption

Component	Flow	Amount
Chemical Solvent (1 m^3)[1]	Manufacture (ecoinvent – monoethanolamine)	0 (deterministic)
CO_2 (1 m^3)	Emission to air (carbon dioxide)	0.42 0.65 0.81 (triangular)*1.847 kg
Heat consumption (1 m^3)[2]	Emission to air (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides) (Particuates, > 10 um) (Sulfur dioxide)	0.5-0.55-0.75 (triangular)* (0.00024 kg 1.02518 E-5 kg 0.00027 kg 0.00019 kg 9.61108 E-6 kg) (deterministic)
Methane Leakage (1 m^3)	Emission to air (Methane)	3.0E-4 4.0E-4

		0.001 (triangular) * 0.668 kg
Electricity Consumption (1 m^3)	Electricity (ecoinvent – market for electricity, low voltage, consequential, Denmark)	0.12 kWh 0.15 kWh 0.646 kWh (triangular)
Water Consumption (1m^3)	Water supply (tap water)	3.0E-5 m^3 * 0.997 kg/m^3 Deterministic)
Maintenance (1 year)	Procurement phase components	0.025 % 0.03 % 0.035 % (triangular)
Avoided Natural gas production (1 m^3)	Manufacture (ecoinvent – natural gas, low pressure)	1 m^3 (deterministic)
Avoided Natural gas combustion at CHP (1 m^3)[2]	Emission to air (Carbon dioxide) (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides) (Particuates, > 10 um) (Sulfur dioxide)	 1.92222 kg 0.00024 kg 1.02518 E-5 kg 0.00027 kg 0.00019 kg 9.61108 E-6 kg (deterministic)
BNG combustion at CHP (1 m^3)[2]	Emission to air (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides)	 0.00024 kg 1.02518 E-5 kg 0.00027 kg

	(Particuates, > 10 um) (Sulfur dioxide)	0.00019 kg 9.61108 E-6 kg (deterministic)

1: The consumption of chemical solvent is assumed to be negligible, due to the regeneration of solvent. In reality, literature suggests that some solvent is consumed in the upgrading process. However, when this was incorporated into the model, the production of solvent represented the overwhelming majority of impact across all categories, despite its relatively small amount. This seems to indicate that the ecoinvent process of monoethanolamine and diethanolamine might not be entirely accurate.

2: The combustion of Bio-natural-gas is assumed to have the same emissions as natural gas. The emissions are based on data from the American Environmental Protection Agency (U.S. E.P.A., 2016). The carbon dioxide from BNG combustion is assumed to be recaptured in biomass, hence its omission.

Table 40 - LCA inventory, end-of-life phase - Chemical Absorption

Component	Flow	Amount
Steel components	Waste Treatment (scrap steel)	19726.25 kg 23712.51 kg (uniform)
Copper components	Waste tratement (scrap copper)	103.75 kg (deterministic)

Appendix 8 – LCA inventory – AD

The Ad plant has been modelled in accordance with the pojrect description of Nature Energy Midtfyn, a joint biogas plant on funen with a 360,000 tons yearly substrate intake (Henriksen, 2015, s. appendix 1, page 5-7, and 1st appendix 1 of the 1st appendix).

All components have, when possible, been estimated in accordance with literature. For complex component that where considered to have a s mall overall impact on the final result, an ecoinvent representation was used when possible. When sources state that steel was used, the component was modelled with low alloyed steel, if nothing else was specified, or if the specified type was not represented in the ecoinvent database. When sources state that concrete was used, the component was modeled with normal concrete, unless the component was in contact with any biomaterial, in which case concrete with a strength of 35 MPa, as this is required for the "aggressive environmental class" in Denmark.

In the case of tanks, concrete or steel, when dimensions have not been supplied, estimates have been made based on similar sized components. The density of steel has been assumed to be 8050 kg/m^3, and the density of concrete has been assumed to be 2251 kg/m^3.

Table 41 - LCA inventory, procurement phase - AD

Component	Flows	Amount
AD Tank	Steel (steel, low alloyed)	167,360 kg 204,000.0 kg
	Insulation (polystyrene foam, slab for perimeter insulation)	800 kg 1200 kg (uniform)
Air Cleaning Filter	Air filter (air filter, central unit, 600 m3/h)	1 (deterministic)
Boiler	Manufacture (gas boiler)	1 (deterministic)
Gas and Digestate Storage Tank	Manufacture (concrete, 35MPa	78.69 m^3 88.69 m^3 (uniform)

Hall for Solid Biomass fraction	Construction (building, hall)	850 m^2 (deterministic)
Heat Exchanger	Manufacture (blow and heat exchange unit, GE 250 RH)	1 (deterministic)
Land Use	Resource/Land (Transformation, from agriculture) (Transformation, to urban, continuously built)	 64 ha 96 ha 64 ha 96 ha (uniform)
Mixing Tank	Manufacture (steel, low-alloyed)	 128,000 kg
Personnel Building	Manufacture (steel, low-alloyed) Concrete, normal	 1440 kg 2160 kg 328 m^3 492 m^3 (uniform)
Piping	Manufacture (polyvinylchloride, suspension polymerized)	2726.09 kg 4089.14 kg (uniform)
Reception hall for biomass	Construction (building, hall)	288 m^3 432 m^3 (uniform)
Reception Tank	Manufacture (concrete, 35MPA	40 m^3

		50 m^3 (uniform)
Sanitation Tank (2)	Manufacture (steel, low-alloyed	7000 kg 9000 kg (uniform)
Silo for energy Crops	Manufacture (concrete, 35MPa)	320 m^2 480 m^3 (uniform)
Technical Building	Construction (shed)	160 m^2 240 m^2 (uniform)
Torch	Manufacture (steel, low-alloyed)	150 kg 390 kg (uniform)
Trucks	Manufacture (lorry, 40 metric ton)	6 (deterministic)

Table 42 - LCA inventory, operational phase - AD

Component	Flows	Amount
Avoided – Outdoor Storage of Cow Manure (1000 kg) (Wesnæs, Wenzel, & Petersen, 2009, s. table a 11)	Emission to air (Ammonia) (Carbon dioxide) (Dinitrogen monoxide) (Methane)	 0.13 kg 4.21 kg 0.0356 kg 1.68 kg

	(Nitrogen) (Nitrogen monoxide)	0.1 kg 0.034 kg (deterministic)
Avoided – Outdoor Storage of Pig Manure (1000 kg) (Hamelin, Naroznova, & Wenzel, 2013, s. supporting info, table s20)	Emission to air (Ammonia) (Carbon dioxide) (Dinitrogen monoxide) (Methane) (Nitrogen) (Nitrogen monoxide)	 0.099 kg 4.39 kg 0.03089 kg 2.4 kg 0.0118 kg 0.00018 kg (deterministic)
Biomass transport, via trucks (1000 kg substrate)	Land Transport (transport, freight, lorry >32 metric ton, EURO6)	5 t*km (deterministic)
Energy crops (maize) – In house storage (1000 kg) (Hamelin, Naroznova, & Wenzel, 2013, s. supporting info, table s5)	Emission to air (Carbon dioxide)	5 kg (deterministic)
Liquid Slurry – Cow Manure – In house storage (1000 kg) (Wesnæs, Wenzel, & Petersen, 2009, s. tabl a9)	Emission to air (Ammonia) (Carbon dioxide) (Dinitrogen monoxide) (Methane) (Nitrogen) (Nitrogen monoxide)	 0.55 kg 11.6 kg 0.0193 kg 2.85 kg 0.0412 kg 0.0137 kg

		(deterministic)
Liquid Slurry – Pig Manure – In house storage (1000 kg) (Hamelin, Naroznova, & Wenzel, 2013, s. supporting info, table s3)	Emission to air (Ammonia) (Carbon dioxide) (Dinitrogen monoxide) (Methane) (Nitrogen) (Nitrogen monoxide)	 0.713 kg 0.27 kg 0.01913 kg 0.54 kg 0.0126 kg 0.0002 kg (deterministic)
Heat, via in house boiler (1 m^3)	Emission to air (Carbon dioxide) (Carbon monoxide) (Dinitrogen monoxide) (Nitrogen oxides) (Particulates, > 10 um) (Sulfur dioxide)	 1.92222 kg 0.00024 kg 1.02518E-5 kg 0.00027 kg 0.00019 kg 9.61108E-6 kg (deterministic)
Digestate Spreading (1000 kg) (Hamelin, Naroznova, & Wenzel, 2013, s. supporting info, table s 16)	Emission to air (Ammonia) (Carbon dioxide) (Dinitrogen monoxide) (Nitrogen oxides) Emission to water (Phosphorus) (Nitrate)	 0.6438 kg 96.2 kg 0.05037 kg 0.0031 kg 0.0555 kg 1.726 kg

	Emission to soil (Copper) (Zinc)	 0.01610 kg 0.584 kg (deterministic)
Maintenance (1 year)	All concrete Components All Equipment components	0.25 0.75 % (uniform) 2.5 3 3.5 % (triangular)
Electricity	Electricity supply (market for electricity, low voltage | electricity, low voltage | Consequential, U)	1.9 % of plant output energy 3.7 % of plant output energy 6.7 % of plant output energy (triangular)
Storage of Digestate (1000 kg) (Hamelin, Naroznova, & Wenzel, 2013, s. supporting info, table s14)	Emission to air (Ammonia) (Carbon dioxide) (Methane) (Nitrogen) (Nitrogen monoxide) (Nitrogen oxides)	 0.122 kg 2.941 kg 1.319 kg 0.01464 kg 0.00023 kg 0.02832 kg (deterministic)
Torch use (1 m^3)	Emission to air (Carbon dioxide) (Methane) (Nitrogen oxides)	 1.91608 kg 3.874E-5 kg 3.4866E-5 kg

Table 43 - LCA inventory, end-of-life phase - AD

Component	Flow	Amount
Steel	Waste treatment (ecoinvent – scrap steel steel)	765071 kg 765311 kg (uniform)
Concrete	Waste treatment (ecoinvent – waste concrete gravel)	1252563 kg 1342032 kg (uniform)
PVC	Waste treatment (ecoinvent – waste polyvinylchloride product)	3407.62 kg (deterministic)