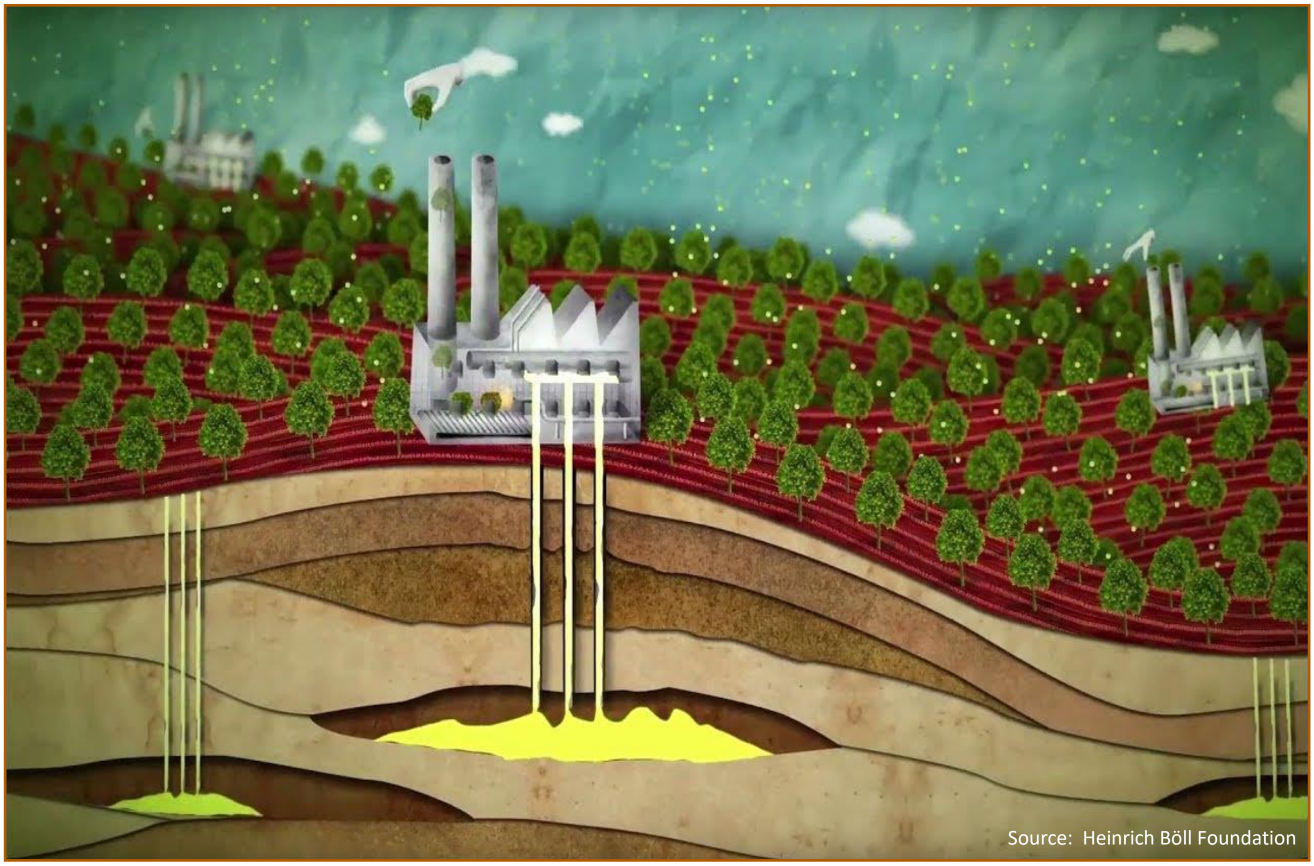
Bioenergy with Carbon Capture and Storage (BECCS) as an approach to achieve negative emissions in Europe

Quantification of biogenic Carbon Dioxide from the major ethanol and UBG plants in Europe. Evaluating the techno-economic feasibility of sequestering those emissions.

Master thesis (GEO4 – 2321)

Supervised by Dr. Martin Junginger



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List of acronyms and abbreviations	
AD	Anaerobic Digestion
ATM	Atmosphere
BECCS	Bioenergy with Carbon Capture and Storage
CAPEX	Capital Expenditure
CDR	Carbon Dioxide Removal
CO_{2_bio}	Biogenic Carbon Dioxide
CO_2_e	CO_2 equivalent
CRF	Capital Recovery factor
DOGF	Depleted Oil and Gas Field (also DGF)
E_PRTR	European Pollutant Release and Transfer Register
EBA	European Biogas association
EC	European Commission
EEA	European Environment Agency
EPA	Environmental Protection Agency (USA)
ETS	Emission Trading System
FHL	Full Load Hours (8760 hours = 1 entire year = 365 days)
GIE	Gas Infrastructure Europe
GMST	Global Means Surface Temperature
IEA	International Environmental Agency
IPCC	Intergovernmental Panel for Climate Change
LCA	Life Cycle Analysis or Assessment
LCV	Lower Calorific Value
MACC	Marginal Abatement Cost Curve
MPa	Million Pascals
Mtpa	Million tonnes per annum
NET	Negative Emission technologies
Nm^3	Normal Cubic Meter
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operation Expenditure
PM	Particulate Matter
PSA	Pressure Swing Adsorption
PSA	Pressure Swing adsorption
ROW	Right-Of-Way (or Right-to-Way)
UBG	Upgrading Biogas or UBGP for upgrading biogas plant
UCCI	Upstream Capital Cost Index
UNFCCC	United Nations Framework Convention on Climate Change
WMO	World Metrological Organizations
ZEP	Zero Emission platform

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Abstract

Since the emergence of industrial development, atmospheric CO_2 concentrations have drastically increased from 280 PPM to 400 PPM nowadays. BECCS is one of the Negative Emissions Technologies that has prospects to substantially remove CO_2 from the atmosphere and aid in meeting the Paris agreement. This thesis explored the techno-economic feasibility of integrating CCS with biogenic emissions generated at ethanol and upgrading biogas (UBG) plants in the European Union. The techno-economic feasibility is evaluated using a Marginal Abatement Cost Curve (MACC) to estimate the cost of the potential amount of biogenic CO_2 that can be abated (€/tonne CO_{2_bio} abated). The gross total biogenic emissions from 22 ethanol plants' potential for storage is estimated at around 2.72 Mt per year; and an annual of 236 kt from 12 UBG plants in Germany. Considering the projects` lifetime of 20 years, a gross total of 60 Mt could be potentially sequestered underground. Considering CO_2 transportation by trucks and using Depleted oil and Gas Fields (DOGF) as a storage point, most cases have an abatement cost of or less than 100 €/tonne). These cases could abate a gross of 2.6 Mt annually with an average 7price of 77 €/tonne. While if pipelines are considered, nine out of ten cases could abate a gross 1.9 Mt annually for a 44 €/tonne. The abatement costs will be the minimum if reused DOGF storage sites are used, while these costs would be at the maximum with saline aquifers, regardless of the transportation type. If ETS would be adapted to include BECCS, implementing CCS with ethanol and biogas plants could become a more favorable pathway to achieve negative emissions. With the current rise of carbon prices in the market, most of the pipeline cases examined would have reached breakeven costs soon. In contrast, with road transportation, an average carbon price of around 80 to 90 €/tonne would be needed for all of the cases to reach breakeven levels. Overall, transportation by pipelines is only possible for plants with an annual capacity larger than 100 kt approximately; however, both trucks and pipelines deliver identical amounts of net emissions. This research shows that CCS integration with ethanol and UBG plants is a cheap pathway of BECCS compared to what is already estimated by the literature, especially by IPCC, 2018. Furthermore, the inclusion of BECCS under the ETS system could assist the EU to reach its targets by 2050.

Keywords: CO_2, cost, ethanol, CCS, biogas, plant, BECCS, abatement cost, storage, transportation, capture, pipeline, trucks

1. Introduction

1.1 Background and problem definition

Since the industrial revolution in the 1800s, the combustion of fossil fuels like coal, oil, and natural gas has tremendously imbalanced the concentration of some gases like Carbon Dioxide (CO_2) in the atmosphere (Kweku et al., 2017). Greenhouse gases (GHGs) like Carbon Dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O), water vapor (H_2O) can function as a gaseous dome trapping the solar radiation from escaping into the outer space, subsequently heating the atmosphere, which causes an increase in the global mean average temperature of Earth (IPOC, 2007). Since the emergence of industrial development, atmospheric CO_2 concentrations have drastically increased from 280 PPM in the 1800s to 400 PPM today (Kweku et al., 2017) - See Figure 1. Continuous emission of GHGs, especially CO_2, can lead to a catastrophic outcome in the near future, which disturbs the climate system with inevitable, devastating events like floods, droughts, desertification, hurricanes, etc. (NOAA, 2019).

During the Conference Of Parties (COP3) in Kyoto protocol in 1997, the legally binding targets proposed that the developed nations must reduce their CO_2 emissions, and the process would be internationally monitored in addition to reporting the total emissions of each party (Scherer, 2013). The most remarkable milestone that emerged from the climate negotiations was at the Paris agreement (COP21) in December 2015, where almost every nation in the world ratified the new treaty to avoid climate change (Falkner, 2016). The central aim of the Paris agreement entails the long-term vision of keeping the global mean average temperature change to well below 2°C above pre-industrial levels by the end of the 21st century (EC, 2019a). Additionally, this long-term goal is pursued to limit the global temperature change to 1.5°C (Hulme, 2016).

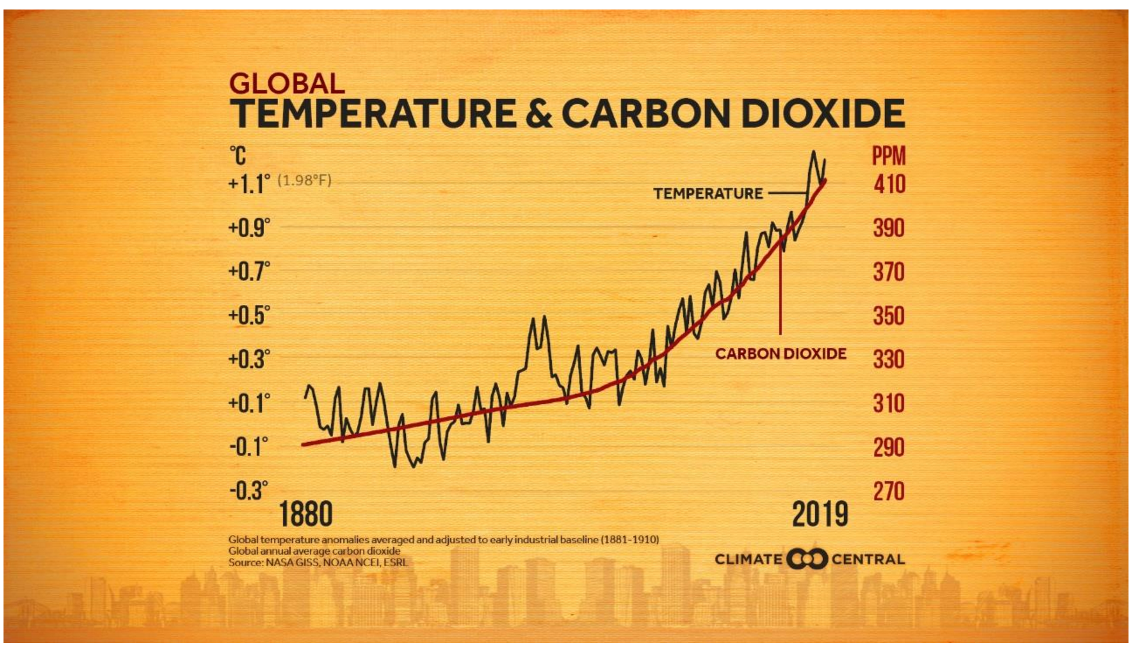

Figure 1: Temperature anomaly in Celsius degrees from 1880 until 2019 following CO_2 concentrations in the atmosphere. Source: Climate Central, 2020

The principal aim of the Paris agreement entails setting targets that engage the treaty parties to operate and develop actively the crucial areas essential to combat climate change. Thus, it orientates the international authorities to the awareness of climate change threat (EC, 2019a). The agreement was forced on November 4, 2016, and up to date, is ratified by 191 parties (out of total 197) (UNFCCC, the status of ratification, n.d.). The European climate target within Paris agreement is assigned under Nationally Determined Contribution (NDC), which requires a 40% reduction in GHG emissions than 1990 levels. Additionally, under its 2030 climate targets which the European Council adopted in 2014, it is required to increase the share of renewables to 32%, and to have at least an improvement in the energy efficiency by 32.5% (EC, Paris agreement, 2019; EC, 2017a). However, according to estimations by climate action tracker 2015, even if the Paris agreement parties fully implement the required contributions to GHG reduction and commit to solid policies after 2030, it would still lead to a global mean temperature rise of 2.7° C by 2100 (EASAC, 2018). Human Business As Usual (BAU) activities have already caused around 1.0°C of global warming in comparison with pre-industrial levels, and with the current rates of CO_2 emissions, global warming would reach - with a high confidence probability - 1.5°C between 2030 and 2052 (IPCC, "SPM", 2018).

The need to limit the Global Mean Surface Temperature Change (GMST or GMSTC) is more urgent than it thought because with the current global emissions, stabilizing the climate change at 1.5 ℃ will likely overshoot before it cools down again. This means that the climate target will be reached or surpassed for a period ranging from years to decades before the climate cools down below 1.5 change of GMST once again – *see* Figure 2. The impacts in the time of overshooting would cause colossal damage to the environment and, for some phenomena, irreversible impacts. For the moment, the occurrence of overshooting seems to be unavoidable as about 90% of the climate models foresee that a period of overshooting will take place (Graves, 2019).

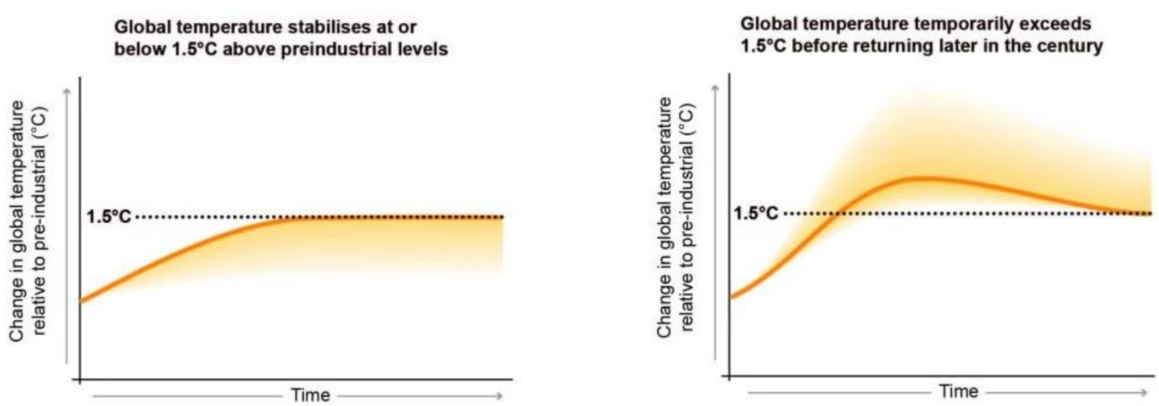

Figure 2: Simple illustration of GMST overshooting before stabilizing at or below 1.5°C (right) Vs. GMST stabilizing at 1.5°C without overshooting (left). Source: Rogeli et al., 2018 (IPCC)

One approach to increase the rates of CO_2 reduction for the European countries and the rest of the world is the Negative Emissions Technologies (NETs) that aim at removing carbon from the atmosphere (EASAC, 2018). All of the possible pathways leading to limiting global warming to 1.5° C with no or limited overshooting utilize Carbon Dioxide Removal (CDR) to a certain degree. Among the CDR technologies primarily relied upon in the Integrated Assessment Models (IAMs) towards limiting global warming to 1.5 ℃ are afforestation and bioenergy with carbon capture and storage (BECCS). Utilization of BECCS is even more required in case of overshooting occurrence. Furthermore, the longer the time it takes for the world to reach net-zero emissions, the more likely the overshooting would strike. Thereby, more deployment of CDR would be required to re-balance the carbon cycle against the net accumulated atmospheric CO_2 to re-stabilize the warming to or below 1.5° C (IPCC, "SR15", 2018).

1.2 Carbon budget and the need for Negative Emissions Technologies

In terms of achieving the targets set and ratified during the Paris agreement in 2015, the European Union (EU) is in the lead in the global transition towards carbon neutrality where the EU countries have already managed to lower the GHG emissions by 22% but increase Gross Domestic Product (GDP) by 58% between 1990 and 2017 (EC, 2019c). The EU policies are on track in delivering the required reduction targets by 2030, and there is a high ambition by the European Parliament to revise the 40% reduction up to 55% GHG reduction by 2030. However, its progress is assessed to be insufficient (climate action tracker, 2019).

Therefore, there is an urgent need to deploy NETs to remove CO_2 from the atmosphere in tandem with efforts to reduce carbon emissions. Due to residence time of CO_2 in the atmosphere (5 to 100 years according to Prentice et al., 2001) and due to its current high concentration rate of more than 400 PPM, even with emissions reductions, high absorption of solar heat takes place (EASAC, 2018). Also, due to the limited emissions budget (carbon budget), only a tiny amount of CO_2 is tolerated for the world to emit in the coming years so that the atmosphere is kept compatible with not exceeding the warming limit of 1.5°C or 2.0°C (EASAC, 2018).

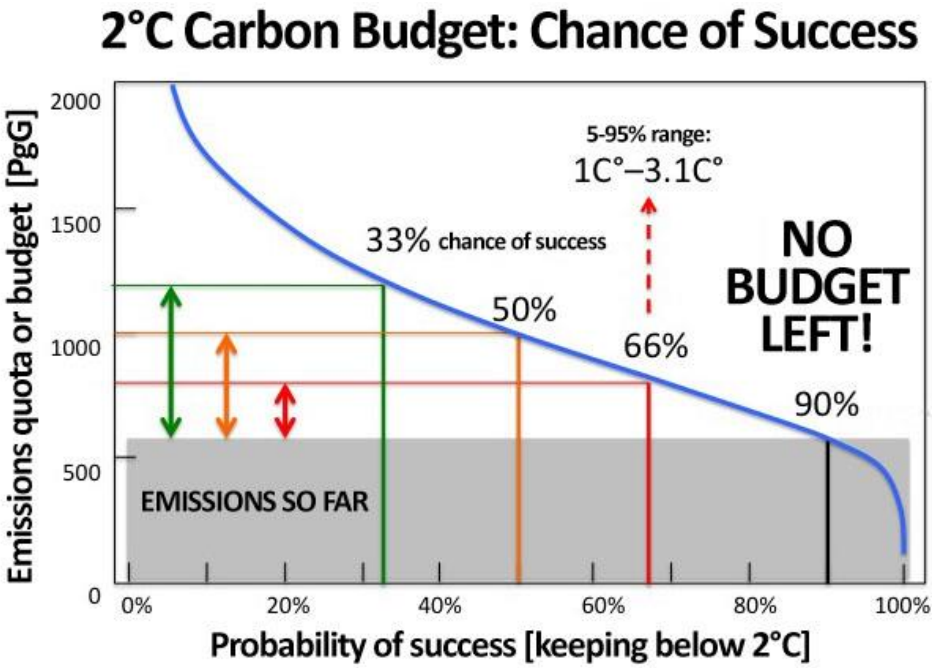

Figure 3: Probability of keeping the global warming below 1.5°C with different carbon budgets. Source: Arnold, 2014. Retrieved from: https://www.tree-of-life.com

Assuming that the global emissions were halted in 2014, there would have been less than a 90% chance of not exceeding 2 °C of GMST; that is how urgent the current state is in countering the potential global warming threat (Arnold, 2014) – see Figure 3. However, since that did not happen currently, from 2019 onwards, the total carbon budget compatible with not exceeding 1.5 ℃ is merely 340 Gt. With the latest annual emissions of around 42 Gt or billion tonnes (billion t), only eight years remains from the timespan (Ritchie and Roser, 2019). Although that amount varies per study, it is still a matter of immediate action required in the meantime. Among many CDR technologies, this study aims at responding to the climate threats by providing additional insight into the option of adopting BECCS in Europe as an approach to reach carbon neutrality, at least by 2050.

1.3 Carbon Dioxide Removal (CDR) technologies or NETs

There are several CDR technologies, each with its potentials, challenges, and barriers. In the following paragraphs, each of the CDR technology is briefly elaborated on based on papers and publications by Pires, 2019 and EASAC, 2018. In the last part, BECCS is presented in detail.

1. Afforestation (foresting) denotes planting of trees capable of storing a large amount of carbon via photosynthesis in an area where previously was not a forest by nature. reforestation is the natural or deliberate replenishing of trees and woodlands that were depleted by the process of deforestation (Calvin, 2019). There are many advantages of afforestation such as prevention of desertification, increased natural habitats for living organisms, job opportunities, improvement of air quality, etc. Disadvantages of **Afforestation** and reforestation include the influence on biodiversity, bringing issues to ecotourism, and It is an expensive practice. If poorly managed, it would cause environmental degradation and damage to the soil, as it happened in China, where it invested in large-scale A/R projects without proper control (Monbiot, 2020 & Cao et al., 2008).

2. Ocean Alkalinity Enhancement involves fostering a naturally occurring phenomenon where the acidification of oceans is reduced by absorbing atmospheric CO_2 (Gagern et al., 2019). Ocean is the largest carbon reservoir, and every 1000 liter contain 120 grams of bicarbonate ions (negative) that are balanced with positive ions from calcium and magnesium. By accelerating the weathering processes, the negatively charged ions (bicarbonate) are increased, and thus atmospheric CO_2 is decreased in addition to ocean acidification. This can be carried out by dissolving minerals or rocks directly in the ocean or by a designed engineering system (Renforth, 2017). Potential OAE or EW capacity is around 2 to 4 Gt CO_2/year by 2050 with a breakeven cost of less than 200$ (USD in 2015) (Hepburn et al., 2019)

3. Ocean fertilization is an approach of geo-engineering that entails stimulation of phytoplankton activities in the ocean, typically in the upper layer (sunlit), to improve photosynthesis by adding nutrients which fosters the uptake of atmospheric CO_2 (Williamson et al., 2012). Some of the side effects of ocean fertilization include an increase of eutrophication, an increase of PH at the lower layer of the ocean due to accumulation of organic carbon (Pires, 2019). Other damaging impacts of ocean fertilization include oxygen depletion, toxic plankton blooms, and disruption of the marine food chain (Geoengineering monitor, 2018).

4. Biochar is a geoengineering technology that aims at mitigating atmospheric CO_2 by growing plants that absorb CO_2 via photosynthesis and are later combusted in low or no oxygen conditions (pyrolysis). This black organic matter is then stored in the soil (Downie et al., 2012). In addition to Carbon sequestration, biochar increases the PH of the soil, nutrients enrichment retention, the cation-exchange capacity, and some other elements that improve the soil quality for plants and agriculture (Deem and Crow, 2017). Sequestration capacity of biochar systems can be up to

1.8 Gt yr^{-1} even without CCS (Mattila et al., 2012), with carbon reservation ranging from decades to millennia (Kuppusamy et al., 2016). The mitigation capacity of biochar depends on its management practice, its interaction in the soil, and its production. Biochar production depends on the cost and availability of the feedstock and how sustainably it is supplied. Other complicated consequences of biochar in the soil include change of surface albedo, water-soil fluxes, and Near-Term Climate forcers (NTCFs) (Tisserant & Cherubini, 2019).

5. DACCS is a "technology that uses chemical processes to capture and separate carbon dioxide (CO_2) directly from ambient air. The CO_2 is then separated from the chemicals and captured so that it can be injected into geological reservoirs or used to make long-lasting products. The chemicals are then reused to capture more CO_2" (American University, 2018. P.1). Current contribution to Atmospheric CO_2 reduction by DACCS is around 9000 t CO_2/year in the world, in addition to an under-development plant with a capacity of 1 Mt CO_2/year (IEA, 2020).

6. BECCS

The notion of BECCS or Biomass Energy with Carbon Capture and Storage/Sequestration functions from that principle where biomass - as a stockpile of carbon – are processed mechanically and chemically to produce energy in the form of fuel, whether gas or liquid, while any generated/emitted CO_2 is flowed separately to be stored in natural geological formations underground – See Figure 4. This way, the absorbed CO_2 by the plants during photosynthesis would be removed from the atmosphere for an extended period, from hundreds to thousands of years (Ernsting and Munnion, 2015; EC, 2017b).

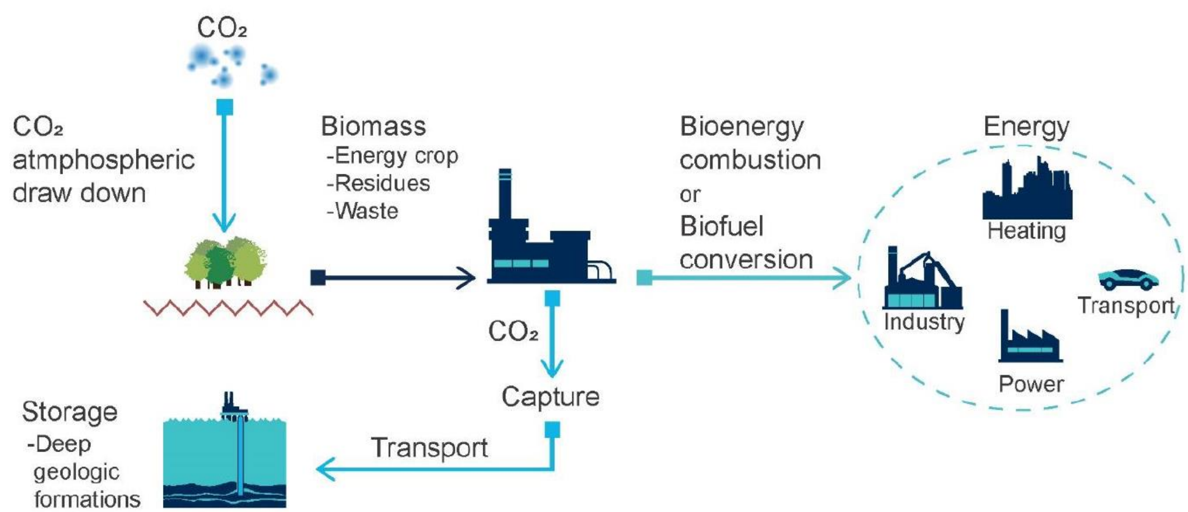

Figure 4:Schematic illustration of BECCS technology. Source: Christopher Consoli, 2019

BECCS is prospected by scientists and academics as one of the most auspicious NE technologies, even though the large commercial scale is yet to be achieved. It is regarded as a NET because the bioenergy is theoretically considered carbon-neutral since biomass combustion leads to carbon emissions that were already a part of the vegetation-atmosphere carbon cycle (Stavrakas et al., 2018). Out of ten various pathways to utilize or remove carbon from the atmosphere, Hepburn et al., 2019 provided that BECCS can have the most attractive carbon utilization or removal potentials with breakeven costs not exceeding 138 €[1] by 2050. Given that in the high scenario, BECCS can have the capacity of 5 Gt CO_2/year with a temporal range from centuries to millennia (Hepburn et al., 2019) – See Appendix A.1 for the MACC graph.

1.4 Scientific background of BECCS and knowledge gap

Globally, BECCS and other NETs are still being discussed whether it is an appropriate method to decrease atmospheric CO_2, which aids in meeting COP21 targets of keeping the GMST change to below 2°C. Some argumentations arise in this sense: how sustainable is the sourcing of the biomass (Karlsson & Byström, 2011). Second, BECCS is not 100% carbon neutral considering the emissions during the supply chain (Pearlman, 2019). Third, concerns about the long-term capability of the storage sites to reserve carbon without the risk of leakage (Gonzales et al., 2020). Fourth, concerns about the possibility of scaling up such technology and the conditions of BECCS deployment and its impacts on the generation of benefit (Fajardy et al., 2019; Karlsson and Byström, 2011).

Details about the utilization of BECCS in the academic literature are still not finalized and are still embedded with uncertainties. The Limited number of BECCS projects hampers BECCS to be addressed and surveyed empirically for further studies about its impacts on a national or even a global scale (Buck, 2019). Until 2019, the number of operational BECCS plants worldwide was only five, which together captured around 1.5 Mega tonnes per annum (Mtpa). From those projects, the only one that is large scale (1 Mtpa) is ADM`s Decatur located in Illinois in the United States, and it produces ethanol from corn with CO_2 generated as a part of the fermentation processes.

Fridahl & Lehtveer, 2018 studied the global potential, investments, and the involved barriers to adopting BECCS. Within this research framework, the following points were investigated: First, investment in BECCS technology has low priority from the governments, and the attention by non-governmental actors is even lower. Second, the study`s review of reported surveys showed an apparent lack of social acceptance of BECCS, especially CCS, making it a barrier to BECCS. The third barrier to BECCS is the lack of policy incentives and insufficient political prioritization.

The uncertainties about BECCS in parallel with its potentiality to become actively addressed in the policies and become an interesting investment target as a robust pathway towards the Paris agreements long-term goal make the topic an urgent and interesting to be further investigated for Europe. In this regard, some studies have covered various aspects of BECCS and provided insights on some challenges that need to be considered. However, what is yet to be solidly known is what will be the lowest cost opportunity to capture biogenic CO_2 at the facility level in Europe, where CO_2 is concentratedly generated and subsequently stores (sequester) these emissions. Within this context, the potential point sources are mainly ethanol and biogas plants, where dense amounts of CO_2 are produced in the processing chain (see Figure 8 in section 1.6.1). For instance, During ethanol production, fermentation results in CO_2 production of 99.9% purity which reduces the capture costs, as is the case with fossil-based plants (Fry et al., 2017).

[1] 160 $ (USD 2015) in the paper.

For biogas plants, the CO_2 steams are considered pure enough and occupy around 40% (with 60% being methane) of the raw biogas (Pentair, n.d.).

1.5 Research objective and research questions

In a general context, this thesis aims to contribute to the body of scientific literature considering Negative Emissions Technologies (NET), specifically the technology of BECCS, as a possible solution to aid the European countries to meet the Paris agreement of keeping the GMST change to well below 2 °C. In particular, this study explores and analyzes the primary biogenic carbon emissions sources at ethanol and upgrading biogas (UBG) plants in Europe, where biomass or bio-based feedstocks are used to generate bioenergy fuels such as liquid fuels, electricity, and heat. This thesis explores the techno-economic feasibility of capturing the generated CO_2 emissions and store them at appropriate storage locations where transportation and storage of quantities of CO_2 are feasible. The third objective is to provide an accurate estimation of the lowest cost required to store one tonne of CO_2 to provide an insight into how cheap this pathway of BECCS could be and in a basic format is compared to other CDR technologies.

Thereby, the research's central question is, ***"To what extent is it feasible to implement Carbon Capture and storage (CCS) with ethanol and biogas plants in Europe as a competitive CDR technology?"***

The main research question can be answered by breaking down the question into the following sub-questions.

1) *What ethanol and UBG plants within Europe to be included in the analysis?.*
2) *What is the total gross amount of biogenic CO_2 that could be potentially sequestered from these plants?*
3) *What is the cost of implementing CCS?.*

3a) What is the cost of capturing biogenic CO_2 from the selected plants?.

3b) What are the suitable transportation methods, and how much they cost?.

3c) What is the cost for CO_2 injection and storage?.

4) *How much net biogenic CO_2 can be sequestered?.*
5) *What is the cheapest cost scenario to abate the biogenic emission within the selected plants?*

1.6 General case study description

This research entails carrying out a techno-economic analysis of sequestering biogenic CO_2 emissions from ethanol and UBG plants where CO_2 steams is pure, thick, and almost need no capture. Avoiding capture and purifying facilitates the capture process and makes it very much cheaper when compared to CO_2 capture from fossil-based Carbon Dioxide (Smolker & Ernsting, 2012). Also, upgrading biogas plants use certain technologies to remove Carbon Dioxide from the raw biogas to obtain pure biomethane (Li et al., 2017). Capturing this rich CO_2 from both processes, further processing it with dehydration and compression, then transporting it to a storage site is considered a low-hanging fruit to achieve negative carbon emissions in terms of technicality and economics (Olsson et al., 2020 (IEA Bioenergy). Both ethanol and biogas plants contribute to a significant amount of biogenic CO_2 considered for CCS in this research. Their background and associated processes, technologies, conversion routes, feedstocks are described briefly in the following sub-sections.

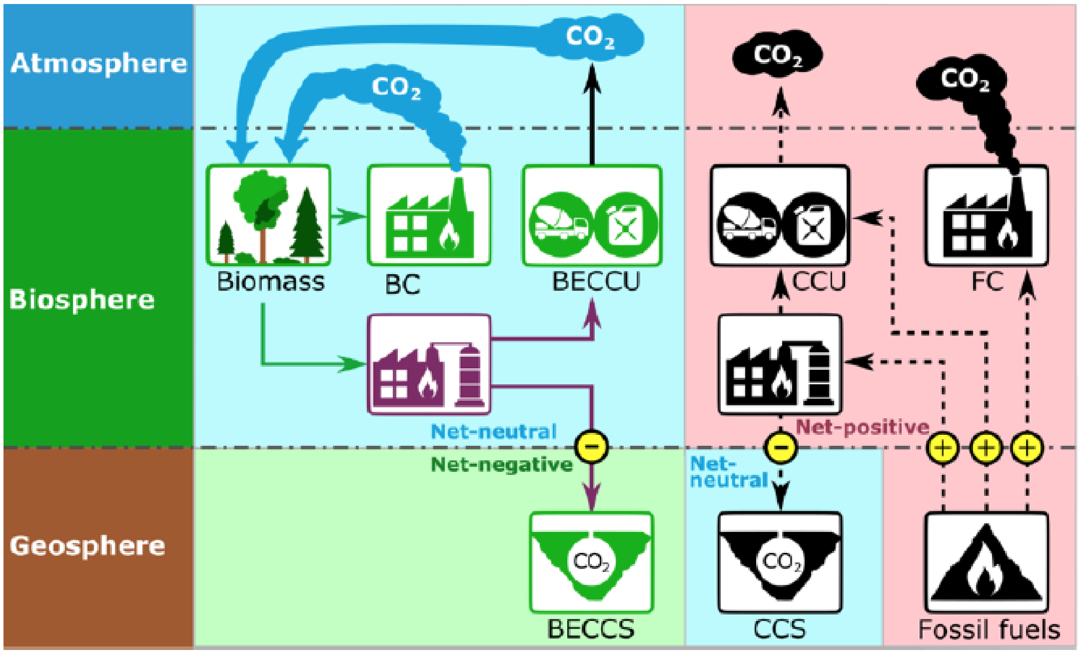

Figure 5: Schematic illustration of bio-CO2 storage (BECCS) compared to fossil fuels. Source: IEA Bioenergy task 40

This thesis's case study analyzes the biogenic CO_2 from the industrial-scale of typical ethanol and biogas upgrading plants in Europe. The research's focus is the gate-to-gate footprint of the biochemical processes of fermentation and anaerobic digestion that contribute to a considerable amount of CO_2 emissions on-site and as a part of the chain. However, the initial GHG emission generated at producing, transporting of the feedstocks to the biorefinery is excluded. Moreover, the use/operation emissions generated from using the products (ethanol and biogas), whether in the form of electricity, heat, or automotive fuel, are excluded. The investigation's primary scope includes plants producing industrial ethanol or food-grade ethanol but excluding other fermentation processes at breweries, for instance. On the other hand, upgrading biogas plants include all the biogas plants where the raw gas is further treated to produce pure biomethane while rich CO_2 is released.

The spatial scope of the investigation includes the region of Europe; however, this is primarily narrowed down to a few countries based on an initial investigation (see Figure 9 & 11). The temporal scope of the case study includes ethanol and biogas plants that are currently operational. However, the range extends to two years where some plants are almost operating; but excluding the shutdown plants. Additionally, some plants experience an expansion in the capacities; but each case is evaluated individually depending on the data's validity or the source`s authentication.

Capacity-wise, larger-scale plants provide an interesting insight for comparison with other mega CCS facilities (bio-based or fossil-based). However, smaller-scale plants are also considered for evaluation. Given that ethanol plants are not as large and widely spread as in the US, the combination of several plants/many plants together is not considered in this study. While for biogas, they are too many in Europe, but on a small scale. Again, they are not collected together, but rather, it is considered to establish a point-to-point connection for each case. The range of capacities starts from 10 kt/year to as large as possible, usually up to a few 100 kt (see methodology section for more details). Thus, each plant, whether ethanol or (upgrading) biogas, is called the case(s) and each with their assigned number in the final inventory list, for instance, case #3 (see results section).

The CCS chain construction and installation for each of the cases are executed simultaneously between 2020 and 2025. Thus, each project's operation time starts by 2025, where the project lifetime is 20 years (until 2045) – see Appendix A.2 for the project's lifetime review from some studies. The variations in the project's lifetimes for each of the CCS steps impose selecting the lowest value among the maximum lifetimes. Based on the literature review, this is usually a collective perspective based on the economy, legislation standards, administration, policies, and technicality (ZEP, 2011; Piessens et al., 2008; Mccoy & Rubin, 2008; Berghout et al., 2015). Therefore, the lifetime of the CCS chain in this study is assumed at 20 years. Other minor assumptions and boundaries are briefly elaborated on in various sections in the methodology.

1.6.1 Biogenic CO_2 from fermentation (ethanol production)

Bioethanol, ethyl alcohol, or Ethanol (CH_3CH_2OH) is produced from the fermentation of glucose resourced from carbohydrates available in the plants (Vohra et al., 2014). The primary feedstocks of bioethanol are categorized into three groups: (1) Biomass containing sugar such as sugarcane, whey, molasses, sweet sorghum, sugar beet. (2) Feedstocks containing starch (grains) such as wheat, barley, corn, cassava, etc. (3) Lignocellulosic biomass such as wood and crops residues, straw, agricultural wastes (Bušić et al., 2018). The first and second feedstocks are considered first-generation feedstocks, while the third feedstocks are considered second-generation feedstocks (Rathore et al., 2019). Complex biochemical processes achieve alcoholic fermentation by some bacteria, yeast, or some other microorganism that breaks down sugars into Pyruvate molecules in a process known as glycolysis. When glucose is processed by glycolysis, it is converted into two Pyruvic acid molecules, which are finally converted to molecules of ethanol and CO_2 (Buratti & Bendetti, 2016).

$C_6H_{12}O_6 \xrightarrow{\text{fermentation}} 2C_2H_5OH + 2CO_2$ + Energy (Elshani et al., 2018)

180 gr/kg $\xrightarrow{\text{fermentation}}$ 92 gr/kg + 88 gr/kg + 146.6 kcal (EUBIA, n.d. & Elshani et al., 2018)

Alcohol fermentation leads to the creation of almost identical molar masses of ethanol and Carbon Dioxide. This is a beneficial methodology to calculate the amount of CO_2 emissions from ethanol plants if the biogenic emissions are not reported.

A common practice to produce ethanol entails (in a simple form) making of the sugar-containing solution from agricultural raw materials. Second, converting sugar into ethanol by fermentation. Third, separate and purify ethanol in distillation–rectification–dehydration (Vohra et al., 2014). The latter reference provides several pathways to ethanol production by first and second-generation feedstocks, namely, sugarcane, corn (two methods), and lignocellulose, illustrated briefly in Figure 6. Dry corn milling is taken as an example for a brief description of the processes involved in making ethanol (see Figure 7) based on United Petroleum and Dalby's manufacturing steps.

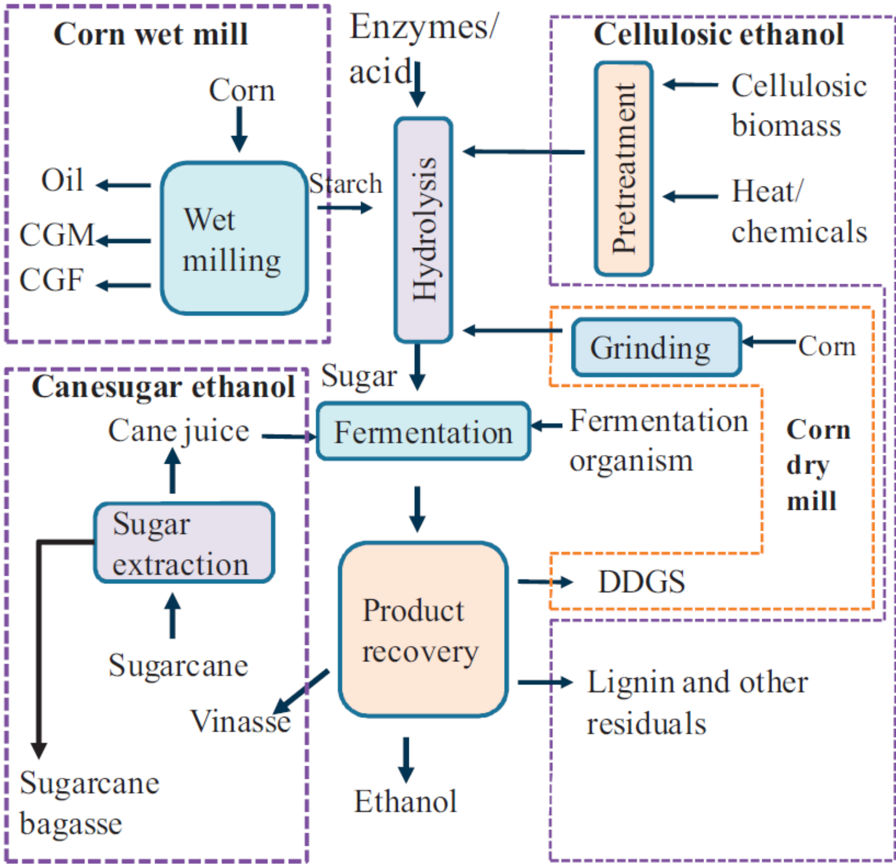

Figure 6: Schematic illustration of ethanol production from four different feedstocks. The four pathways use a similar fermentation process but different ways to recover sugar. Source: Vohra et al., 2014

1. Milling: the quantities of corn grains are passed through mechanical hammers (hammer mills) for crushing. The ground particles form a fine powder called meal or starch.
2. Liquefaction: water and enzyme (alpha-amylase) is added to the meal for liquefaction at high temperature (around 85 ℃), producing mash.
3. Saccharification or hydrolysis: After the mash is cooled down, another enzyme (glucoamylase) is added to generate fermentable sugar.
4. Fermentation is the most crucial process relevant for this study because it is the step where biogenic CO_2 is emitted. It is accomplished by adding yeast to the fermentable sugar in a process that lasts up to two full days.
5. Distillation: At this stage, CO_2 is generated as a by-product of fermentation and expelled. The remaining non-fermentable residual exit the process as co-products known as distillers Dried Grains Soluble (DDGS) or just (DDG).
6. Dehydration: the distilled alcohol is dehydrated by removing the existing water making the alcohol purity 99.8%.

(United Petroleum, 2017; CropEnergies AG. N.d.; Vohra et al., 2014)

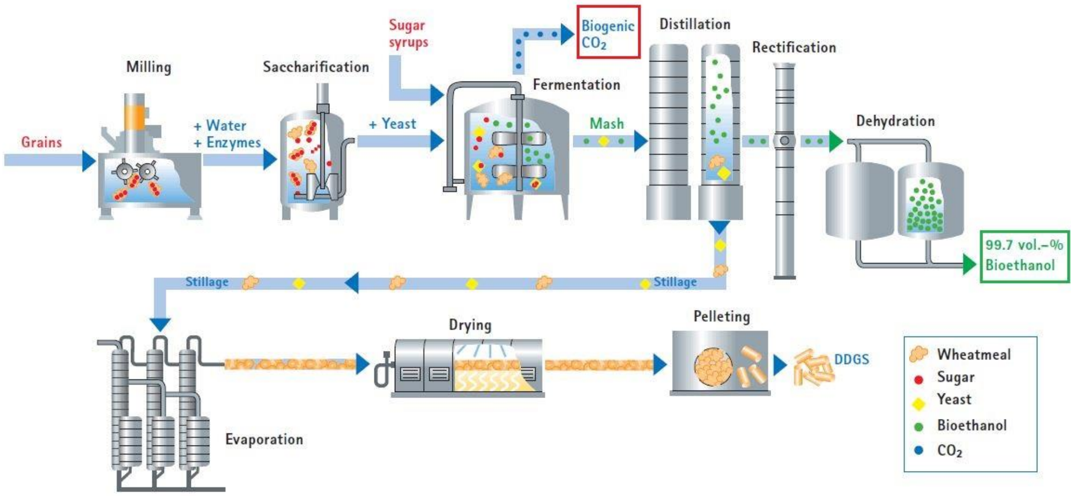

Figure 7: Ethanol production from dry milling of grains and producing biogenic CO2 at Manheim ethanol plant-Germany. Source: CropEnergies AG Mannheim, 2011. See Appendix A.3 for a Figure of Anderson's ethanol plant (Aerial view).

The utilization of ethanol dates back to the late 1800s (Solomon et al., 2007). ethanol`s first use was to power an engine in 1876 by Nicolaus Otto, who invented the modern four-cycle internal combustion engine. The modern industry of ethanol of today dates back to the 1970s when it was developed as an alternative to petroleum-based fuel. Due to its abundance and the easy process of producing it, corn grains dominated ethanol production as the primary feedstock at that time (Gustafson, n.d.). The feedstocks available for ethanol production today are numerous; in Europe, the most promising feedstocks, from an environmental perspective, are wheat and sugar beet (Bušić et al., 2018).

The ethanol market in Europe bloomed directly after introducing the biofuel directive in 2003; however, the sustainability requirement was taken into account only in 2009. Globally, the US and brazil top the global production of ethanol, while Europe is the third major production of ethanol (Bušić et al., 2018). Within Europe, France, Germany, the UK, Hungary, Belgium the Netherlands top the list for Ethanol production (Flach et al., (USDA/FAS) 2019) - (see the complete list in Appendix A.4). Based on these data, the initial spatial scope to search for relevant ethanol plants within Europe is highlighted in Figure 9.

According to Fry et al., 2017, the ethanol industry's innovation throughout history was significant, based on numerous studies. The ethanol industry experienced substantial energy consumption development, water usage reduction, reduced costs, carbon intensity improvement, and added values from by-products. Moreover, it is noteworthy that ethanol production provides a substantial opportunity to capture the by-produced volumes of CO_2 from fermentation (see Figure 8).

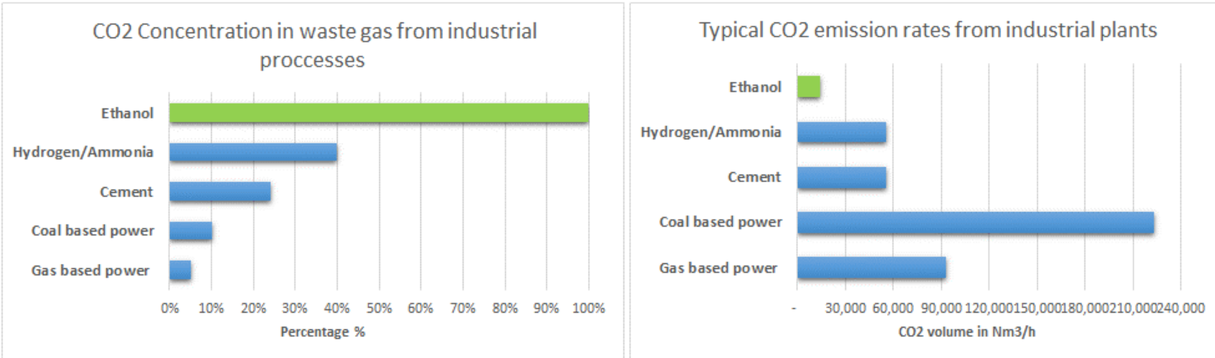

Figure 8: Biogenic CO2 emission compared to other sources, including foss-based industries. source: Fry et al., 2017

Figure 9: Ethanol production in Europe in 2019. France produces an immense amount of ethanol in Europe with 1000 Million liters; Germany is the 2nd with 785 Million liters. Source: Flach et al., (USDA/FAS) 2019). Map generated with https://mapchart.net

1.6.2 Biogenic CO_2 from Anaerobic Digestion (AD) – biogas plants

Degrading of organic materials by microorganisms in the absence of Oxygen leads to biogas generation in a process known as Anaerobic Digestion (AD) (Scarlat et al., 2018). AD is a complex multi-processes system including biochemical, microbiological, and physical-chemical processes (Náthia-Neves et al., 2018). Feedstocks for AD include livestock manure, food waste, energy crops, crop residues, fats, oils, greases (EPA, 2021), sewage sludge (from municipality), industrial wastes such as ethanol stillage (M Kirk & Faivor, 2019). Biogas is a preferred renewable source of energy due to its high energy content, and the process reduces the carbon from the wastes, making them less polluting to the atmosphere. Moreover, the process of energy recovery is more cost-effective than other biological processes (Náthia-Neves et al., 2018). The AD process's main outputs are CH_4 and CO_2 with traces of other gases, Particulate matter (PM), moisture, Sulphur compounds, ammonia, and contaminants like Volatile Organic Compounds (VOC). However, biogas components can differ from plant to plant and depending on the feedstock used and operations conditions (Kuo & Dow, 2017). Biogas is used as a renewable feed to electricity and heat; when upgraded, it is fed into a natural gas network or used as automotive fuel. In Europe, biogas is favored for electricity generation; Germany tops the European countries in biogas production (Vagonyte (EBA, 2010).

While CH_4 is the main content of the biogas components (50% to 70%), the rest of the gases and other impurities (water content) are considered contaminants. The process of removing negative gases (H_2S, Siloxanes, VOCs, NH_3, and CO) from the raw biogas is called cleaning biogas. The 2nd process involves improving the Lower Calorific Value (LCV) of the biogas by increasing the CH_4 content, which is achieved by removing the CO_2 or converting it to CH_4 (by reacting CO_2 with H_2). The latter is called biogas upgrading to generate biomethane that emulates the traditional natural gas (methane content < 95%) (Angelidaki et al., 2018).

Biogas production in Europe experienced a crucial improvement in recent years with the number of plants and production capacities increased drastically. Policy schemes supported the growth of biogas production in some European countries (Scarlat et al., 2018). On the other hand, demand for renewable energy, advancement in technologies, cheaper costs, higher efficiency, advanced upgrading units, and development of the biogas market facilitated the production and growth of biogas/biomethane in the EU. Gross inland energy consumption of biogas increased dramatically from somewhat below 42 PJ to around 705 between 1990 to 2017 in EU28. The number of biogas plants in EU28+Swtizerland+Norway+Serbia increased from around 6k in 2009 to around 18k in 2017. For biomethane plants or upgrading biogas plants, the number of plants increased from just 187 plants in 2011 to 540 plants by 2017 in EU28+Norway+Swtizerland. The biomethane production in this sense increased from just 2.7 PJ in 2011 to 70 PJ in 2017 (Bioenergy Europe, 2019). The distribution of the 70 PJ[2] biomethane among the EU countries is illustrated in Figure 10.

[2] In the resourc report, the production of biomethane is in ktoe, 1,664 ktoe = 69.66 PJ

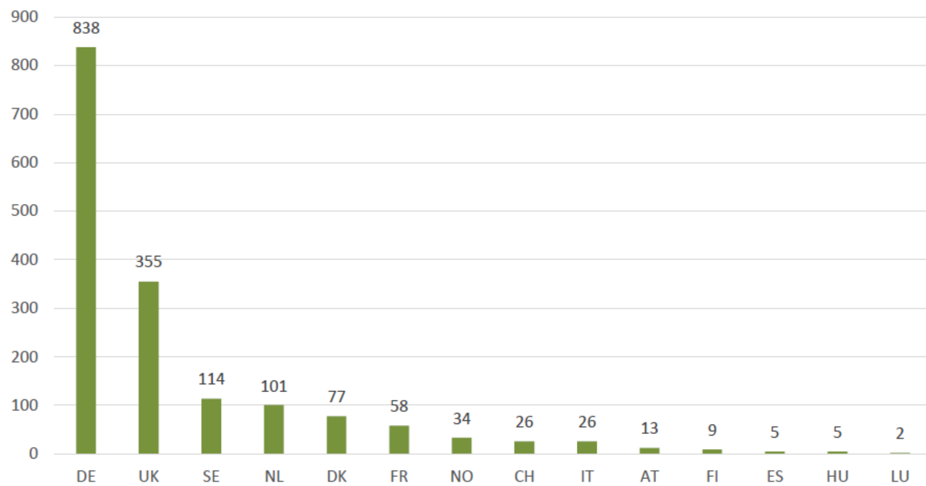

Figure 10: biomethane production (ktoe) in European countries in 2017. Source: Bioenergy Europe, 2019. 1 toe = 41.848 GJ (=11.63 GWh).

Total biogas production in EU28 members in 2017 was 16,826, where Germany, the UK, and Italy represented 46.6%, 16.2%, and 11.3% of it, respectively. Therefore, the initial spatial scope of investigation for biogas plants lay within the countries highlighted below (Figure 11).

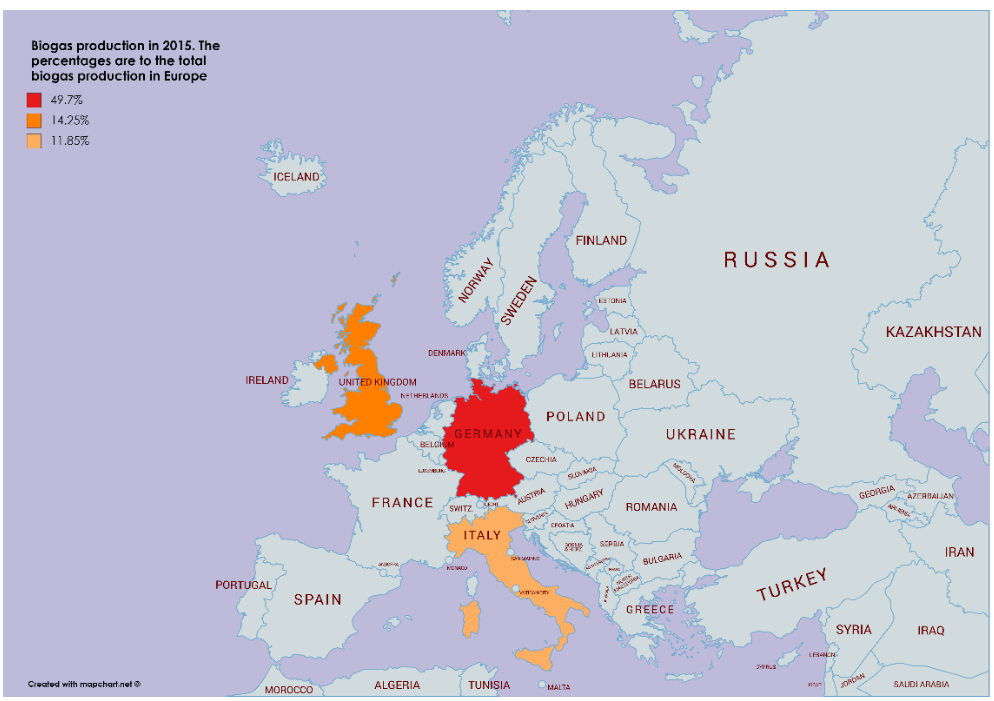

Figure 11: Biogas production in Europe in 2015. The three highlighted countries together represent 75.8% of the total biogas production in Europe. Map generated with https://mapchart.net

Several technologies are used to upgrade biogas on commercial or pilot level, including Pressure Swing Adsorption (PSA), Absorption (water scrubbing, organic physical scrubbing, and chemical scrubbing), membranes, and cryogenic upgrading. For smaller capacities (250 Nm^3/h), water scrubber is the cheapest (€/kWh), while for the larger capacities (2000 Nm^3/h), the prices are almost identical (Petersson & Wellinger, 2009). All the available pathways for biogas upgrading technologies are presented in Appendix A.5

According to Khan et al., 2017, Membrane technology provides the most advantages among all the available techs for biogas upgrading. The valuable points of membrane technology include low capital and O&M cost, availability for small capacities, high CH_4 recovery ratio (> 96%), not hazardous for maintenance, environmentally friendly, the process requires less energy consumption, and the technology is easy to be installed. Historically, Membrane has shared the most significant share among gas separation technologies for the last four decades (Khan et al., 2017).

The steps for upgrading biogas using membrane technology are illustrated in Figure 12, where Pentair upgrades biomethane and CO_2 recovery units. However, the CO_2 recovered is food grade rather than non-food grade. The technology entails using hollow fibers compacted in bundles that permeable to the contaminants and undesired impurities but blocks the methane and, to some extent, Nitrogen. Before the membrane part, the water, aerosols, and oils are filtered to avoid degrading membrane performance. H_2S, on the other hand, is removed by activated carbon in the first place (Petersson & Wellinger, 2009).

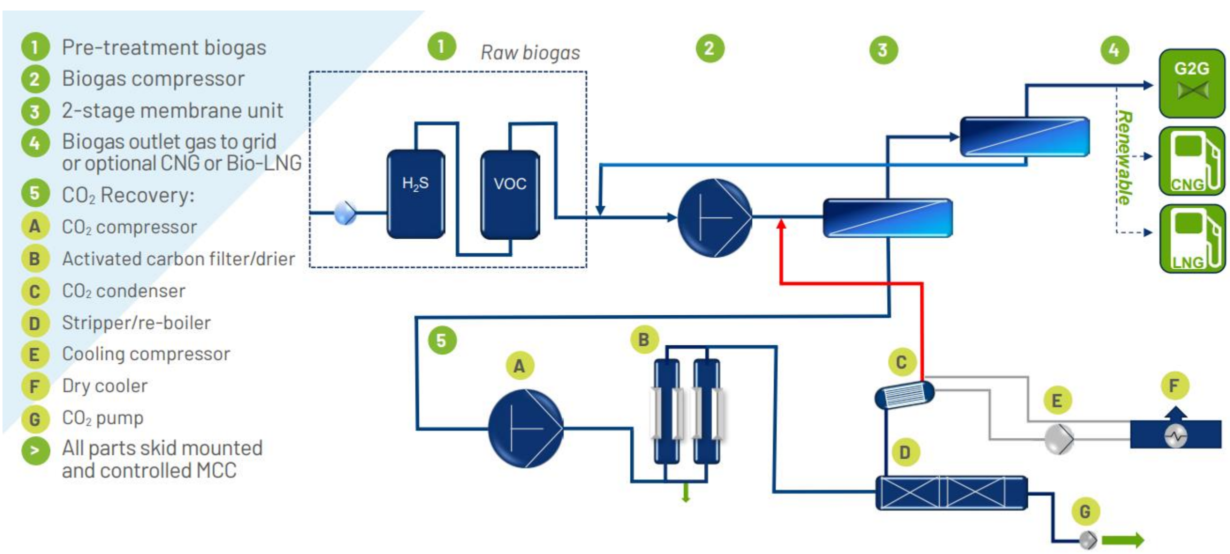

Figure 12: steps towards increasing the concentration of methane using membrane technology, in addition to the CO2 recovery unit. Source:www.foodandbeverage.pentair.com

2. Theory

2.1 Tools to Apply the theories

Various tools and principles were used to construct or calculate a specific value required in the steps. Some of these elements are based on general or particular theories and systems. In the following sections, the essential tools conducted in the methodology to generate the values required to answer the research question or sub-questions are presented. A top-down method is used to break down the tools required as per the outcome.

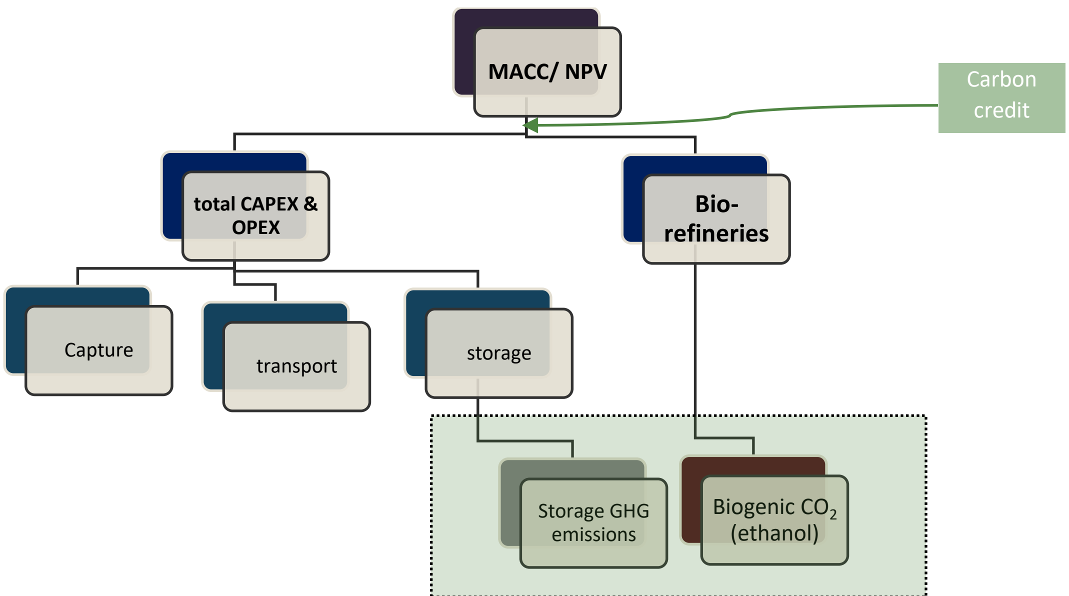

Figure 13: simplified demonstration of the top-down method to identify the required tools

It can be observed from the above diagram that numerous elements are required to reach the final calculation of a MACC or NPV since both the tools are interlinked and require similar elements for calculation. The total CAPEX of the CCS is obtained from the three steps of capture, transport, and storage; however, capture for ethanol and biogas differs a little. The transportation method has two methods (trucks and pipelines) as well. The storage or injection site has 2 to 3 types that can be considered. Each of the three steps has its GHG emissions deducted from the annual CO_2 masses for each case so that the potential amount of abatement CO_2 is calculated.

2.1.1 Marginal Abatement Cost Curve (MACC)

This research's main question entails calculating the cost of abatement (or mitigation) of 1 tonne biogenic CO_2 (€/ton_{CO2}). The essential tool used to perform such calculations is called the Marginal Abatement Cost Curve (MACC). MAC or MACC is a powerful tool used by policymakers to compare mitigation costs for various technologies. Using MACC can evaluate whether reducing large amounts of CO_2 is technically possible (Vogt-Schlb et al., 2015). Additionally, MACC helps the decision-makers regarding which technology/project offers more considerable potentials regarding the abatement potential (WALGA, 2014). The MACC formula (equation 1) is developed by Blok et al., 1993, which was used to calculate the specific cost of every unit of primary energy saved.

$$C_{abatement} = \frac{\alpha.\ I + C - B}{\Delta CO_2} \quad \text{……equation (1)}$$

Where $C_{abatement}$ is the result of abatement cost (€/tonne_CO_2), α is the capital recovery factor (CRF) or annuity factor. I is the initial investment cost or the CAPEX (capital expenditure), a one-time cost for construction or installing the technology or the project. C is the annual cost, usually the cost of Operation and Maintenance (O&M) of the project or the particular step. O&M can include the cost of electricity, heat, or other regular operation or maintenance costs required. B is the benefits; it refers, in this study, to selling the carbon credits as part of the Emissions Trading System (ETS). ΔCO_2 is the annual masses of CO_2 abated. The total amount of biogenic CO_2 available for sequestration minus the annual GHG (CO_2) emissions from applying the CCS chain. The capital recovery factor (α) is calculated depending on the discount rate and the project`s lifetime (LT)

$$\alpha = \frac{r}{(1-(1+r)^{-LT}} \quad \text{……equation (2)}$$

Where r is the discount rate ranges between 4% to 10% in the literature, and LT is the project`s lifetime.

MACC is not a curve graph but rather a series of steps along the X-axis representing the capture costs or benefits of particular technologies. These charted steps or lines are prioritized per mitigation measure ranked from the most cost-effective to the most costly (Ibrahim & Kennedy, 2016). The X-axis represents the mitigation potentials, while the Y-axis represents the costs. In this study, abatement cost is mainly required; therefore, the benefit (B) is disregarded.

$$C_{abatement} = \frac{\alpha.\ I + C}{\Delta CO_2} \quad \text{……equation (1a)}$$

2.1.2 Net present Value

From an economic perspective, a project is only initiated if it is transparent to the investors that the benefits (cash inflows) are more significant than costs (cash outflow). (Blok & Nieuwlaar, 2017). Unless if the company or the corporation is granted a subsidy from the government or another public body. The economic assessment prior to the project start is implemented because every project can be risky to some extent. Numerous tools are available to evaluate a project or technology attractiveness in terms of economic performance. These analysis tools seem different; however, they share the same backbone principle. One of the most successful and widely-spread tools used for economic assessment is Net Present Value (NPV). The approach depends on discounting both cash inflows and cash outflows in the future from the project (Žižlavský, 2014). A project`s NPV is calculated by having two parameters; one is the project`s CAPEX, while the second one is Net cash flows (benefits – costs). The discounting rates convert the future`s cash flows into their values from todays' perspective (Xu, 2015).

$$NPV = -I + \sum_{i=0}^{n} \frac{B_i - C_i}{(1+r)^i} \quad \text{……equation (3)}$$

$$NPV = -I + \frac{B - C}{\alpha} \quad \text{……equation (3a)}$$

*Where B_i is the benefit of the project in the year i, C_i is the project's cost in the year i. r is the discount rate, I is the initial investment (*Blok & Nieuwlaar, 2017). Equation 3a is used when the annual cash inflow and cash outflows are constant throughout the project`s lifetime, which is the case in this research. A project is considered profiting if NPV is > 0; if NPV is negative, then the project is cost-ineffective. These tools and formulas are known as scale laws or learning curves. Scale law is used when the available cost of equipment or raw material, or even the capital cost of technology, is known for a particular scale different from those required (Blok & Nieuwlaar, 2017).

2.1.3 GHG inventory (partial LCA)

Life Cycle Analysis is a tool used to assess the industrial emissions of GHG or solely Carbon Dioxide emissions to evaluate the environmental performance of a process, industry, or technology. A full LCA cycle is called cradle-to-grave, starting from raw materials production to completing the product, usage/consumption, and disposal at the last stage (Sharma, 2017). LCA aids in generating a robust assessment of direct or indirect GHG emissions referred to shortly as CO_2 equivalent (CO_2e). In the field of energy, the produced energy is compared to the amount of GHG generated and expressed then as carbon or GHG intensity (g CO_2_e/kWh – or MJ, or GJ, etc. (McCay et al., 2019). A complete LCA consists of four components: goal and scope definition, inventory analysis, impact assessment, and interpretation. The most pivotal part of an LCA is the inventory part (Jiménez-González et al., 2000). It is the essential part of GHG assessment in this study because the GHG emissions are inventoried merely for the sake of calculation and not interpretation or improvement. For this thesis, only two scopes are identified to conduct the inventory (see section 3.2.4). According to EPA, the GHG inventory process consist of 4 stages: (1) initiating the start plan with scope and inventory plant. (2) Collect data and quantify GHG emissions. (3) Developing a plan for inventory management. (4) setting reduction targets and monitoring the process (EPA, 2021). In this research, only the first two steps are conducted to estimate the total GHG emissions from the CCS chain; to calculate the total mass of CO_2 abatement.

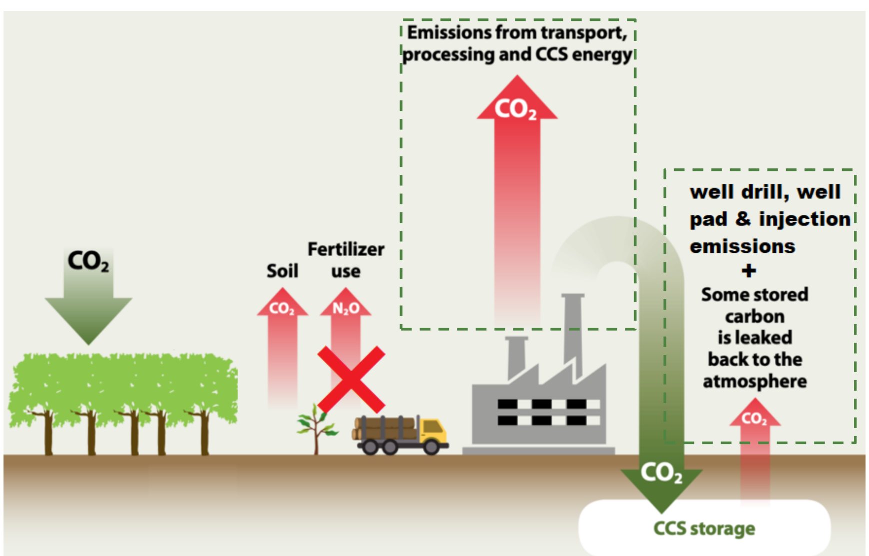

Figure 14: Simplified illustration of the GHG inventory scope. Only CO_2 emissions in the dashed rectangles are included. Source: FERN, 2020).

2.1.4 Scaling factor

In the academic world, there is always a need for more literature and data availability; however, that is not the case sometimes. Some prices of costing data for a particular technology or equipment might be unavailable. Academics and experts use some tools to convert the costs between different currencies when the available cost might be from a different region with different currency and with different exchange rates. Moreover, cost indices are used to develop the cost from an older year to a newer year, and vice versa (Blok and Nieuwlaar, 2017)

$$C = C_{ref} \left(\frac{P}{P_{ref}}\right)^{R} \quad \text{.......equation (4)}$$

(Blok and Nieuwlaar, 2017)

C is the cost of equipment, C_{ref} is the cost of reference equipment (known) with capacity ($P_{reference}$ also known). P is the capacity of the equipment. R is the scale factor, constant. Depending on the type of equipment, traditionally, a scale factor of 0.7 or 2/3 is used. "the capacity for many types of equipment increases with the third power of the size (volume), whereas costs only increase in a quadratic way (surface area). The overall effect is that the cost increases less than proportionally with the scale; this is often indicated as "economies of scale" (Blok and Nieuwlaar, 2017, P.225).

2.2 Emission Trading System (ETS) and Carbon market

In pursuit to combat climate change and reduce the European GHG emissions, the European Commission developed a market instrument in 2005 to reduce CO_2 and other GHG emissions (BMU, n.d.). Emissions Trading System (ETS) is the largest and most eminent international ongoing system for trading GHG emissions allowances. It creates financial incentives for the large emitters to curb their emissions (EU Climate Action, 2014). ETS's rationale is that the policymakers in the EU report annually the amount of CO_2 allowed being emitted in that year in a country (BMU, n.d.). EU ETS is a "cap-and-trade" system where the country`s reduction target determines the cap in that year (NEA, 2016). The cap sets a fixed amount of GHG that's allowed to be emitted by the companies. These emissions are expressed in the form of allowances or permits where the companies receive them or trade these permits among them. The cap level is decreased over time to create a reduction in GHG emissions (EC, 2017c). An emitter must halt its emissions equivalently to the received allowances or buy them from the market (EU Climate Action, 2014). If the emitter fails to do either, heavy penalties on emissions must be paid by the emitter. On the contrary, if an emitter saves specific amounts of GHG emissions below the cap limit, then the allowances (permits) can be traded in the market (see Figure 15) or saved for future emissions (EC, 2017c). Every allowance or permit is equivalent to one tonne of CO_2. Giving the fixed amount of allowances creates a monetary value for each of the allowances, developing what is known as the carbon market. Based on supply and demand and the variations of the operations and investments in emissions reductions creates valuable fluctuations in the carbon price (NEA, 2016). Currently, the BECCS technologies do not fall within the ETS system and thus are allocated with allowances and cannot trade the avoided emissions. Bioenergy plants are considered neutral because the emitted CO_2 is considered green for being the art of the natural carbon cycle.

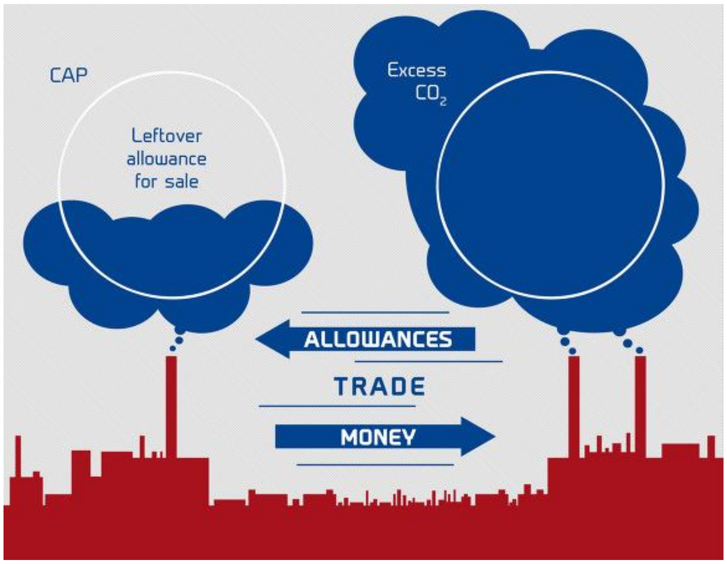

Figure 15: illustration of cap and trad within EU ETS system. Source: Adenekan, 2017 (www.tradenews.com)

However, for a private company to invest in establishing a CCS, there should be an economic driver so that the investment pays off plus profits. Another option is if the company is granted with subsidy from the government or an independent organization.

The global economic crisis of 2008/2009 caused a sharp fall in the prices, including the carbon market. Another factor included the import of international credits to the EU. Since 2009, carbon prices have experienced downgrades; declining from a range of 20€ - 25€/tonne CO_2 between 2005 to 2008 to a range of 10 € - 15€ between 2009 to 2011. Further, it decreased the prices to a range of 5€ - 10 € per tonne CO_2 between 2012 to 2018. Afterward, the EU commissioning introduced the "Market Stability Reserve" in 2015 to protect the carbon price from fluctuating drastically (Demertzis and Tagliapietra, 2021). Gerlagh et al., 2020 showed that the MSR works well against the demand fall and economic crisis, and it stabilizes the market price of carbon. The latter concluded that the carbon price fall induced by the COVID-19 pandemic was much less than the price decline that occurred due to the economic crisis in 2009.

2.3 Theory behind CCS chain

The CCS chain consists of three steps, namely, capture, transport, and storage. Each of the steps includes a couple of general principles that are described below generically.

2.2.6.1 Capture

The capture process is the first step where decarbonization technologies start. Three main routes for carbon capture are available (Feron and Hendriks, 2005).

1. Post-combustion processes: the process entails removing Carbon Dioxide from flue-gas streams (after burning the fuel) consist mainly of Nitrogen, Oxygen, and impurities (SOx,

NOx, and particulates). The capture occurs at a pressure of 1 bar and low CO_2 content of around 1%-20%. Post-combustion processes have two primary steps: energy conservation, where power is made, and the separation and concentration of CO_2 (Feron and Hendriks, 2005).

2. IPCC defines pre-combustion capture, 2005 as *"Pre-combustion capture involves reacting a fuel with oxygen or air and/or steam to give mainly a 'synthesis gas (syngas)' or 'fuel gas' composed of carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO2 and more hydrogen. CO2 is then separated, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as boilers, furnaces, gas turbines, engines and fuel cells"* (Davidson, 2011).
3. Oxyfuel combustion capture involves burning the fuel with concentrated Oxygen up to 98% to assure Oxygen's reaction with the carbon content of the flue gas to generate CO_2. The combustion product then also contains water and some other gases. Then, CO_2 is recovered from the steam with rich-CO_2 content in addition to some water and traces of Nitrogen. The challenge in this technology is to separate Oxygen from air to form pure Oxygen by means of cryogenic, which requires a massive amount of energy. However, an innovation in this sense is emerging, which entails using chemical looping combustion (CLC) (Basile et al., 2011).

Biomass utilization as a source of energy is implemented in two ways; one entails the combustion of biomass directly to produce heat feeding to electricity generation. It can also be used for industrial processes like cement, pulp, iron, and other productions. In this method, the capture is implemented like in the methods described above. The 2nd biomass utilization method entails producing gases and liquids (biogas, bioethanol, others) through biomass fermentation or digestion. In this method, the CO_2 stream is nearly pure and requires no further capture (Consoli C., 2019) but compression and dehydration.

2.2.6.2 CO2 transportation

CO_2 can be transported practically by four means; pipelines, ships (barges), trains, and trucks. Trucks and trains are only feasible (economically) options for small scales and are unlikely to be used for large CCS projects. The pipeline is the most mature means of CO_2 transportation, especially for large-scale CCS. However, depending on the route between the CO_2 source and the storage site, ships can be more feasible from an economic perspective (Metz et al., (IPCC), 2005). In this thesis, two transportation methods are utilized; road transportation by tankers and pipelines. Each of the methods is separately evaluated based on large and small-scale sources of biogenic CO_2.

For a pipeline design for fluid transportation, it is essential first to identify the fluid's main characteristics, which is, in this case, Carbon Dioxide. The CO_2 stream must be first purified, conditioned, and pressurized to the designed pressure (Serpa et al., 2011). Lot is known about transportation by pipeline due to the maturity of the method for CO_2 transportation from fossil power plants to storage sites of almost 50 years[3], at least in the US (Noothout et al., 2014). Generally, pipelines are considered the most viable ways of CO_2 transportation for large volumes

[3] In the article CO_2 pipelines` age is 40 years; however, up to this year, it is 47 years.

and over long distances. Utilizing pipelines, CO_2 usually transported under conditions of pressure between 8.5 bar to 15 MPa, and temperature between 13 °C and 44 °C to maintain that CO_2 remains in single-phase (Leung et al., 2014). In contrast, truck transportation of CO_2 is yet to bloom in the academic library.

2.2.6.3 CO_2 storage

CO_2 can be stored underground in the geological formation such as saline aquifers or depleted oil/gas fields (DOGF). At present, geological reservoirs are the most feasible option to store a vast amount of CO_2 for the sake of sequestering atmospheric carbon dioxides emissions. Traditionally, a geological reservoir can accommodate several gigatons of CO_2 by means of physical or chemical mechanisms (Leung et al., 2014). Typically, reservoirs consist of layers of porous rocks such as sandstones at a depth of 1 km below the ground or seabeds situated under impermeable layer rocks are referred to as cap rocks. The cap-rock layer act as a sealing roof to prevent the gas from escaping. Depleted oil and gas reservoirs are more suitable than saline aquifers since they stored fossil-based commodities for millions of years (IEAGHG, May 2007).

Ideally, a storage reservoir has three main characteristics[4]. First, the reservoir capacity must be suitable to store the determined amount of CO_2 captured at the source plant and is planned to be stored over the lifetime period. The porous rocks are generally at a depth of below 800 m underground to ensure that when CO_2 is injected, it converts to a supercritical phase where more CO_2 can be stored. Second, CO_2 must be stored permanently. The suitable reservoir with appropriate sealing layers (low permeability) to prevent CO_2 from escaping upwards. The third is injecting CO_2 through deep boreholes at reasonable rates, usually around 1 Mt per well annually in large-scale CCS projects (Zeroco2, n.d.).

There are only several onshore commercial CCS facilities in Europe at the current scale of availability, and all are set to be operational from 2024 onwards (Global CCS Institute, 2019) – see Figure 16. Also, there are several demonstration pilot projects and CCS hubs that are strongly scattered around different regions of Europe. These facilities are mostly clustered in the far north-west of Europe and are mainly located in the coastal regions to facilitate transporting the CO_2 to the off-shore storage sites (Global CCS Institute, 2019). Moreover, all of these CCS facilities have at least one assigned at-site CO_2 source.

An alternative method entails using the abundant underground gas storage sites of GIE hypothetically (see Figure 17). This hypothesis is based on the idea that European land is sufficiently fertile for CO_2 injection and storage utilization. Furthermore, many European member states could also investigate their land geologically and are prepared to initiate such projects based on their policies, regulations, and technical capability (see section 3.2.3).

[4] According to Jonathan Pearce, Head of the Carbon Dioxide Storage Team and a Principal Geochemist at the British Geological Survey (BGS) with 30 years' experience (https://www.securegeoenergy.eu).

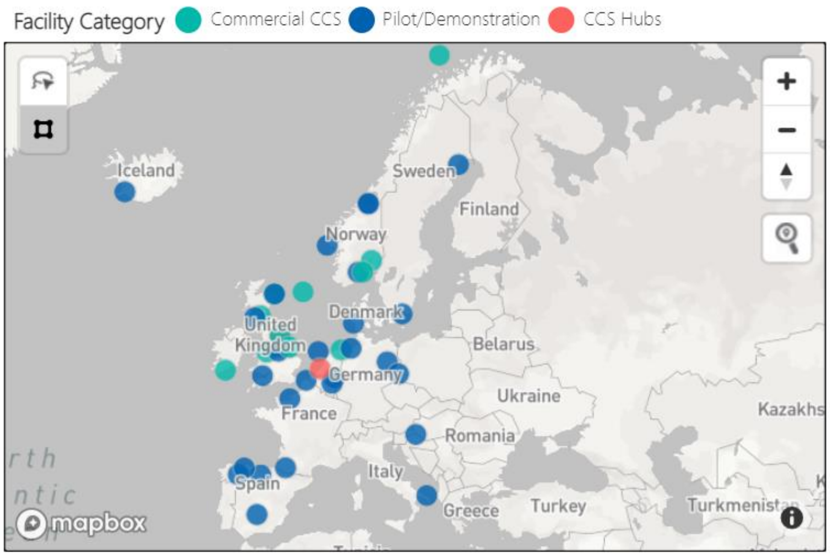

Figure 16: CCS projects around Europe. As indicated above the Figure, each of the colored circles represents a particular type of project mentioned. Source: Global CCS Institute, 2019 (Facilities - Global CCS Institute (co2re.co)

On the other hand, whether underground storage points are suitable to be converted or utilized as appropriate CO_2 storage points or not, and whether temporarily or permanently, they represent points where geological reservoirs exist abundantly in Europe. Therefore, more geological reservoirs could be established, and many more CCS projects could be initiated currently or in the near future.

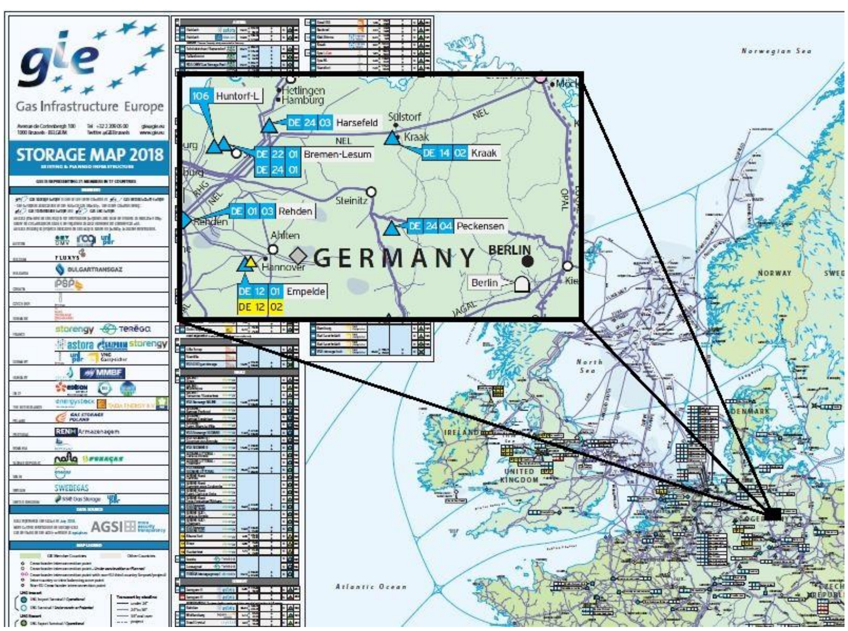

Figure 17: Shows the abundant GIE storage points in Europe updated in 2018. The enlarged spot in Germany includes around ten underground storage points. Source: GIE, 2018

3. Methodology

This research's methodology is based mainly on literature review and data collection from various resources explained in the following sub-sections. Some of the information and relevant data were collected via online interviews with some experts in bioenergy and other pertinent fields (See Appendix D). Other sources of information include communicating with many personnel and corporations in various European countries via direct phone calls or emails.

3.1 The cost calculation

The total cost of implementing the CCS system consists of the collective costs of the three steps, namely, capture, transport, and storage, in addition to their annual O&M costs. Based on the reviewed literature, capital costs consist of buying raw material, constructing units, installing equipment, labor costs, fuel costs, etc. The annual O&M costs are somewhat different for each of the steps; however, it is usually a fixed percentage of CAPEX.

Many factors cause some variations in the cost calculation because every study implements the costing of CCS diversely. Nevertheless, in this thesis, the costs are calculated separately for each of the three steps, capture, transport, and storage, including the O&M costs. Furthermore, the cost of capturing CO_2 from ethanol and biogas plants, transportation methods by trucks and pipelines, and storage types are all calculated individually (see Figure 18).

Following equation (1a) in section 2.1.1, the elements needed to calculate the abatement cost for each of the cases are Investment cost, annual costs, annuity, and the amount of abated (avoided) emissions. The investment cost is expressed as CAPEX; annual costs are expressed as O&M cost, and the annuity is calculated by equation (2). Finally, the abated emissions are calculated by subtracting the new emissions generated by implementing CCS from the collected annual biogenic emissions from the sources.

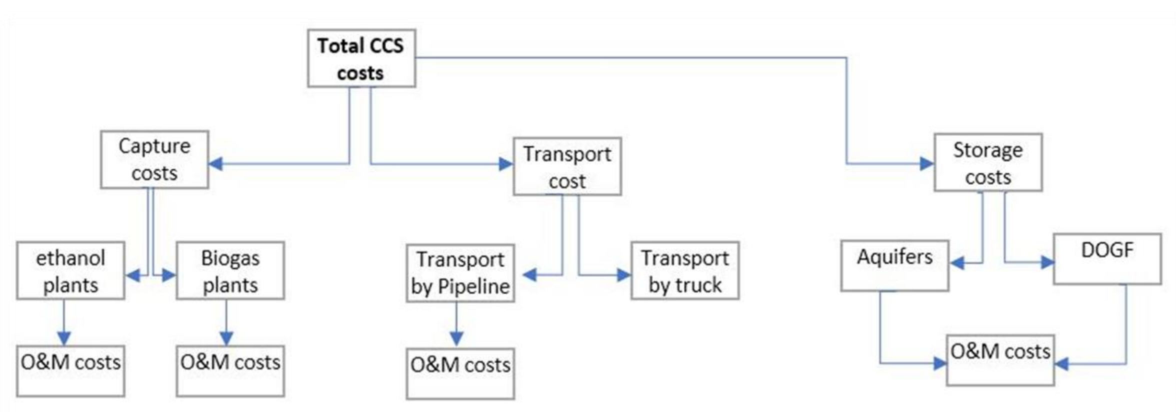

Figure 18: illustration of total CCS costs broken down into three steps with each have one or more sub-divisions

3.1.1a The cost of carbon capture from ethanol plants

The majority of the peer-reviewed papers and publications from independent organizations consider the steam of CO_2 from fermentation at ethanol plants to be pure. Therefore, no considerable effort is needed to capture CO_2, as is the case in fossil-based power plants. Similarly, almost all of the works of literature reviewed consider the capture CAPEX to be just dehydration and compression (Restrepo-Valencia & Walter, 2019; Arasto et al., 2014; Fabbri et al., 2011; de Visser et al., 2011; Fry et al., 2017, and others). In this part, the CAPEX is calculated based on the average of two methods.

Method 1: Economies of scale

The CAPEX is calculated by applying the scale factor principle explained in section 2.1.4. it depends on calculating the cost for a known number of units in the reference case and apply it to the second case with a known number of units. The difference in the plant sizes results in variations in the final cost per unit for the total production, i.e., the costs per unit decrease with more production units (Piessens et al., 2008). The scale factor of 0.67 (as used by Kreutz et al., 2008; Meerman et al., 2012, Knoope et al., 2015) is usually used in fossil-fueled plants fossil-powered industrial productions. In this method, the same scale factor is applied to capture CAPEX from a study by Laude et al., 2011 on utilizing CCS from two ethanol plants in France. The study's cost is treated for inflation/deflation using Upstream Capital Cost Index (UCCI) from IHS Markit Appendix B.1) as recommended by M. Knoope (personal communication. February 26, 2021).

Method 2: The trendline curve

The method entails using the powerline curve created based on other CAPEX data from a few studies. The scarcity in the number of studies on CCS from ethanol plants hindered collecting more data. This is because the majority of the studies focus on CCS application on fossil-fuel combusting plants or from the industrial processes where enormous amounts of CO_2 (greater than 1 Mt/year) is emitted, which makes the CCS chain cheaper due to economies of scale (Kuramochi et al., 2010; Berghout et al., 2015). The trend line (power curve) connects the data smoothly based on the plant size on X-axis and the cost value on Y-axis (see Figure 19). It is noteworthy that the data from Fry et al., 2017 is based on two scenarios for CO_2 utilization from ethanol plants in the US. Scenario 1 considers the capture cost from 15 ethanol plants, while the 2nd scenario presents the capture cost for 34 plants; however, the capture costs and the CO_2 masses were given collectively. Therefore, both the values were divided by the number of plants in each scenario to obtain the average CAPEX per plant, and the plant capacity, respectively. The costs were converted to euros using Xe.com and updated to 2020 using UCCI by IHS Markit.

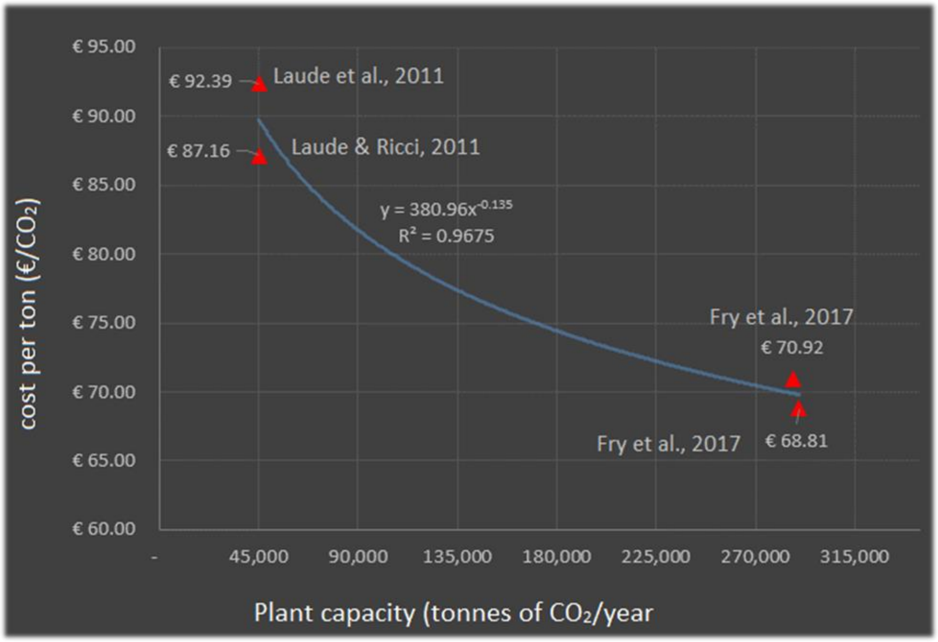

Figure 19: Graph of the articles' costs (method 2: power line curve).

It is noteworthy that both the methods lead to highly similar costs, especially for the smaller plant capacities. The difference increases while the plants' sizes grow larger. Therefore, the average of the two methods is utilized. To review the cost calculation by applying method 1 and method 2, see Appendix C referenced with the section number.

3.1.1b Capture CAPEX for UBG plants

Similar to method two from the previous section, the capture CAPEX for biogas plants was established based on applying the trendline curve. However, the CAPEX data is obtained directly from Pentair company based on an expert`s evaluation rather than to be collected from the literature. Pentair is specialized in developing sustainable and cost e-effective technologies for upgrading biogas plants. Pentair`s innovations include energy-efficient routes/tech installations of biomethane upgrading and CO_2 recovery systems in 1500 plants distributed in many locations such as in the UK, USA, The Netherlands, etc. (Pentair, 2021). The CAPEX data for CO_2 recovery from upgrading biogas was provided by David Hynes, sales manager of biogas and CO_2 recovery at Pentair in Ireland. A few case scenarios were discussed to conclude the CAPEX estimation for such bio-plants as follows.

Plant capacity (Nm^3/h) - raw biogas inlet	Recovery ratio	CO_2 ratio	CO_2 mass (kg/h)	Cost (million Euros)	O&M	Electricity consumption
850	95%	44%	703	1.2 + (4%) [a]	3% to 4%	220 kWh/tonne of liquid CO_2
1750	95%	44%	1446	1.8 + (4%)	3% to 4%	220 kWh/tonne of liquid CO_2
3000	95%	44%	2479	2.5 + (4%)	3% to 4%	220 kWh/tonne of liquid CO_2

Table 1: Calculation parameters of upgrading biogas`s CAPEX as suggested by Hynes, D. (Personal communication. March 25, 2021 (Pentair).
a: 4% represents the overall cost for civils. The lower range is estimated at 3%, but the higher end is selected in this thesis.

The parameters in Table 1, like the recovery factor and CO_2 ratio, are somewhat different from those presented in section 3.1.2b. This difference led to discrepancies in the final CAPEX calculation compared to if, for instance, 89% recovery is used rather than 95%. However, all the possible scenarios were calculated for the sake of comparison. It was found a negligible difference. Eventually, the capture CAPEX is calculated considering the raw biogas capacity as the base (Figure 20), which was cheaper than the second using annual CO_2 mass as the base (Figure 21). Moreover, a ratio of 4% is used for O&M in addition to the electricity cost, which is estimated at 220 Wh/kg CO_2 or kWh/tonne CO_2 (Hynes, D. and Driessen, J. Personal communication. March 25, 2020).

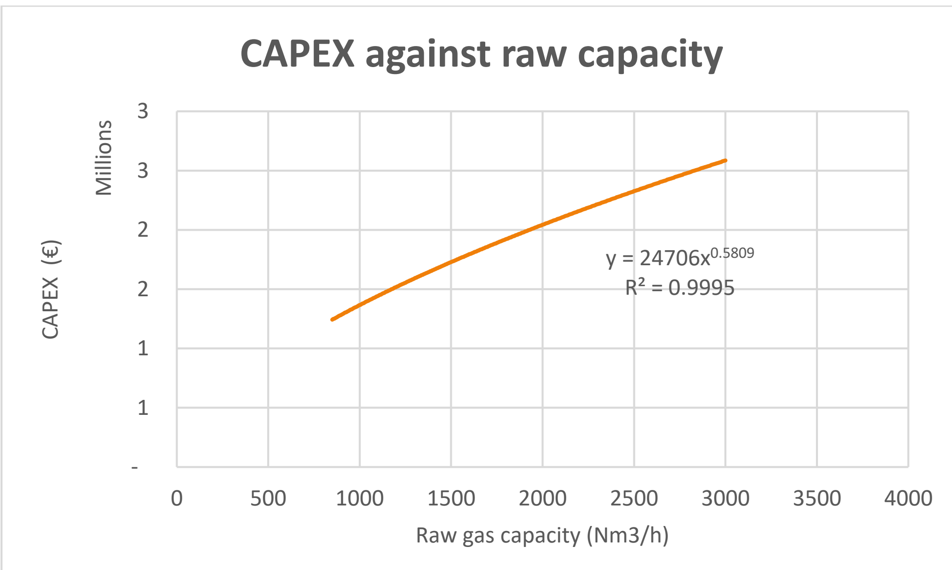

Figure 20: CAPEX establishment by considering the reference cost against the raw gas capacity.

It is remarkable to note that many biogas upgrading technologies are available, such a chemical scrubber, Membrane, PSA, water scrubber, organic physical scrubber, and some other new technologies proposed in Yousif et al., 2017 and 2018 and Vo et al., 2018. However, the same CAPEX methodology is used for all the UBG plants in this work while considering the CO_2 ratio and recovery ratio for each of the UBG plants. Review the application of the formula in Appendix C, referenced with the section number.

Figure 21: CAPEX establishment by considering the reference cost against the annual CO2 mass flow

3.1.2a The cost of CO_2 transportation by road (truck-tankers)

For the cost estimation of CO_2 transportation by trucks, it was pre-assumed that road transportation could be a valid method given the modicum masses of CO_2 from bioethanol and biogas plants. However, the paucity of peer-reviewed literature regarding CO_2 transportation by trucks imposed a foreseen challenge. Only da silva et al., 2018 presented in detail the calculation in CO_2 transportation from ethanol plants to a collector hub in Brazil.

Given the road transportation simplicity compared to pipelines, it facilitated and expedited the costs to be quoted in a real-time manner rather than compiling from peer-reviewed paper. The transportation costs by trucks were collected from Den Hartogh, a company specializing in transporting chemical commodities in Europe and headquartered in the Netherlands. See Table 2 for the costing parameters gathered from Jan Halin, the company`s commercial manager (personal communication. January 19, 2021)

Activities/proccess	unit	value	Notes
Loading liquid CO_2	€/	100	Based on 2-hour service (first 2 hours)
Trucking cost (departure)	€/km	1.8	Excluding tolls on the route
unloading liquid CO_2	€	100	Based on 2-hour service (first 2 hours)
Equipment cost	€/day	60	A traveling distance up to 500 km
Total cost	€/trip	261.8	A trip of 1 km

Table 2: Calculation parameters for truck transportation. Source: Halin, J. January 12, 2021.

It is noteworthy that a trip and its return should be within 500 km to be counted as a one-day trip; if more than 500 km, then the equipment cost is multiplied. Moreover, the 100 € costs are meant for the driver and the truck only since the company considers the first 2 hours always free for loading and unloading. However, if the loading and unloading last longer than 2 hours, Den Hartogh charge for demurrage costs (Halin, J. January 21, 2021). See an example of costing by truck in Appendix C.

3.1.2b The cost of CO_2 transportation by pipelines

The physical parameters and other design elements play a substantial role in the construction and operation of a pipeline project. However, pipelines' overall capital cost is divided into four main elements (Horánszky, Forgács, 2013). The majority of the literature identifies these four costs as a standard model to conclude the total capital cost for pipelines (Skaugen et al., 2016; Van der Zwaan et al., 2011; McCoy and Rubin, 2008; Gao et al., 2011; Parker, 2004; and Horánszky and Forgács, 2013). Therefore, this study follows the same principle to estimate the cost for CO_2 transportation by pipelines. The implementation of the following equations obtains the final CAPEX for the pipeline of each case.

$CAP_{pipeline} = C_{material} + C_{labor} + C_{ROW} + C_{Miscellaneous} + C_{additional}$ ....equation (5)

$C_{O\&M} = O\&M\ (\%) \times CAP_{pipeline}$ ....equation (6)

Where $CAP_{pipeline}$ is the estimated capital cost for the pipeline as a collective of the four components (€), plus the costs for the pipeline control system, surge tank, and extra pumps if needed. $C_{material}$, C_{labor}, C_{ROW}, $C_{Miscellaneous}$, $C_{additional}$ *represent the costs for materials, labor, Right-to-Work or Right-Of-Way (ROW), Miscellaneous, and Additional costs respectively (€).* $C_{O\&M}$ is the annual cost allocated for operation and maintenance *(€)*. O&M (%) is the unitless fraction that is decided for each pipeline project as a share for O&M (3% in this study).

Other costs apart from the four components include the pipeline control system, surge tank, and pumps ($C_{additional}$). By analyzing the study by Dubois et al., 2017, and comparing the relevant pipeline systems, the costs of the three components were found to be, the Pipeline control system is 94 k€, surge tank cost 1 M€, and the price per pump is 213 k€ (Dubois et al., 2017). The prices were evaluated against the UCCI index for updating to 2020, and they were converted from USD to Euro using Xe.com. See an overview of the study in Appendix B.2.

For each of the four components, both models by Piessens et al., 2008 and Knoop, 2015 are used. Except for material cost where weight-based cost by Knoop, 2015; Gao et al., 2011 is used.

Regarding the O&M cost, usually percentage of the total pipeline cost is used. Various references used different ratios range between 2% to 4%. Mechleri et al., 2017 used 3%; Gao et al., 2011 used 4%; Chandel et al., 2010 used 2%; Berghout et al., 2016 used 2%; Dahouski et al., 2009 used 2.5% and finally, Dubois et al., 2017 reported an average of 2.6%.

According to Dubois et al., 2017, the O&M or Annual Operation Expenses (AOE), or OPEX cost, is divided into pipeline O&M, equipment and pumps O&M, and electricity cost. All together represent on average 2% to 4% of the pipeline`s CAPEX.

3.1.2b.1 Material cost

There are some models for the cost of the material supply; however, most of the models are outdated enough to be eligible for an inflation correction. Among the costing models for the material supply, the weight-based model is used. In this sense, two methods were used where both of them depend on the weight of the required pipe. Also, both the equations are a modification of the same weight-based principle but used for comparison.

Gao et al., 2011 provided a model for a pipeline design in China that calculated the total capital cost by considering the share of material supply to the total pipeline cost. The latter part is excluded in this study for being straightforward and not giving an appropriate estimation of the CAPEX, i.e., f_m (See Appendix B.3).

$C_{material} = C_p \times W_{steel}$ ………………………………………………………………………………………….Equation (7)

$W_{Steel} = 0.02466 \times t \times (OD - t) \times L$ …………………………………………………………………….Equation (7a)

(Gao et al., 2011)

Where $C_{material}$ is the total cost of material supply (€). C_P is the price of steel in €/Kg. W_{steel} is the weight of all the pipes per case. 0.02466 is the constant generated by multiplying the density of steel (7,700 Kg/Nm3) by the Pi value; it was then divided by 10^6 to obtain the unitless constant (Fang, M. 2011 as cited in Knoope, 2015). *OD is the outer diameter (mm), L is the length of the pipeline (m), t is the pipe`s wall thickness (mm).* Hence, the cost of steel represents the material supply cost.

The other way is the cost model by Knoope, 2015; it also depends on the pipes' weight and providing the material's density (carbon steel or stainless steel, or others).

$C_{material} = t\pi \times (OD_{NPS} - t) \times L \times P_{steel} \times C_{steel}$ …………………………………………………….Equation (8)

Where OD_{NPS} is the outer diameter of the Nominal pipe (m), P_{steel} is the density of steel (kg/m^3), and, C_{steel} is the steel cost in €/kg (Knoope, 2015). The steel density is 9700 kg/m^3 for all steel grades used in the reference. Also, the steel prices were 1.17 €/kg for X42 steel grade and 1.50 €/kg for X80 (Knoope, 2015).

Nevertheless, the density for steel pipes used in this thesis is 7850 kg/m^3, and GMM provided the most recent prices. According to Van der Mijn, the sales/products manager at GMM provided quotation prices and recommended the pipe types/standards to be used. The cost of carbon steel pipes (ASTM A-106 Gr. B) is 1.4 €/kg, and for stainless steel pipes (ASTM A-312 TP 304L) is 3.75 €/kg (Personal communication. February 25, 2021).

Carbon steel pipes are broadly used in the oil and gas industry for high strength, and it is weldable and durable, but it is also low resistant to corrosion (Jatmoko & Kusrini, 2018). However, its low prices make this type of pipe competitive with stainless steel pipes. Given the broad use of carbon steel pipes in the literature and its low prices, it is also used in this thesis. See Appendix C for quantifying the cost of pipes for case #1.

3.1.2b.2 Labour cost

The labor cost represents the cost of constructing the pipeline incorporated in transportation, welding, and installing the pipeline, i.e., setting the pipes in the trench (Knoope, 2015). While the materials cost proportionate directly with the pipe diameter, the labor cost, on the other hand, increases with smaller pipe diameters (Van der Zwaan et al., 2011). The way of calculating labor cost varies highly in the literature according to several factors such as the pipeline's primary engineering design, location of the project (which region/country), and other legislative and regulations. The labor costs are obtained using two costing models, one by Piessens et al., 2008 and another by Knoope, 2015.

First, the model by Piessens et al., 2008 was updated by Knoope, 2015 for inflation rates, given that the model was published in 2008 with cost values from 2005 (Knoope, personal communication, February 26, 2021). To be used for this thesis, the formula is further updated to

2020 by considering the inflation rates using UCCI from IHS Markit (See Appendix B.1). It is also important to note that Piessens developed this model for Belgium, which is also valid with the regional scope of this research, i.e., European countries, including Belgium.

$C_{labor} = (941 \times OD - 50.7 \times OD \times \ln(L)) \times L \times F_{r\_labor}$ ....Equation (9)

OD is the pipe's outer diameter (m), ln is the natural logarithm for the distance (m), and L is the distance length in meters. F_{r_labor} *is the labor cost multipliers per region*. F_{r_labor} *for Western Europe is 1.0, and for eastern Europe, it is 0.8* (Energy, E., 2010). Although this study's cases are scattered in all of Europe, including East Europe, the same factor is used for all the cases. The application of equation (9) on case #1 can be reviewed in Appendix C.

Another method entails using an average fixed cost based on the width of the pipe diameter across the pipeline length, i.e., cost per m^2. It is estimated that the cost per 1 m^2 of onshore pipe installation is 756 €/m^2 (Knoop, 2015). Alternatively, the cost is calculated as a fixed amount per pipe diameter per 1 m length, estimated at 19.24 €/OD"/m. where OD" is the outer diameter in inch (Knoop, 2015). It is remarkable to say that both calculations are 99.8% identical. See Appendix C for the demonstrated example. The cost estimation is based on data by the U.S. Federal Energy Regulatory Commission (FERC) for projects between 2008 to 2012 and is valid for developed countries. For the developing countries, the cost is corrected by region factor (Knoope, 2015).

3.1.2b.3 Right-Of-Way (ROW) & damages costs

ROW is a strip of land with different widths, usually between 10 m to 50 m, that contains the pipeline of a project, and it is assigned to gain access to the structure (Degermenci, 2019). ROW enables the workers to access the pipeline for inspection, testing, maintenance, or emergency/safety cases. Generally, ROW areas are protected from being used for other activities to maintain public safety and preserve the ROW boundaries (Enbridge, n.d.). Like the previous section, the ROW cost model is adopted from Piessens et al., 2008 and Knoope, 2015 and is updated for inflations using HIS Markit's UCCI indices. The following ROW cost is based on a 15 m width for a 4" pipeline and 25 m for a 12" pipeline (Piessens et al., 2008).

$C_{ROW} = (217 \times OD + 43.44) \times L \times F_{r\_ROW}$ ....Equation (10)

F_{r_ROW} *is the correction factor for Right-Of-Way per different region (1.0 is used).*

Secondly, The ROW cost by Knoope, 2015 is a fixed value based on the average of ROW costs of five years (2010 to 2015) from FERC. The fixed cost per pipeline length (m) of 76 €/m is justified because the same land is needed to construct pipelines, whether for small or big diameters. This was collected from FERC for other pipeline projects between 2010 to 2015 (Knoope, 2015). See Appendix C to review the application of the equation (10).

3.1.2b.4 Miscellaneous costs

Miscellaneous costs represent all other costs not covered by material cost, labor cost, and ROW cost. Miscellaneous costs commonly include Administrative costs like filing fees and overhead, engineering costs, surveying, contingencies, Supervision, telecommunications, taxes, freight, allowances for funds during the construction period (Parker, 2004; Global energy monitor, 2021). Miscellaneous cost using Piessens et al. method is calculated by equation (11) and the method by Knoop in equation (11a).

$C_{Misc.}$ = (579x OD − 21.7 x OD x ln(L)) x L x $F_{r\_Miscellaneous}$ ……………………………….........Equation (11)

Secondly, miscellaneous cost by Knoope, 2015 entails using a fixed percentage of both material cost and labor cost following the methodology by Bureau et al., 2011.

$C_{Misc.}$ = 25% x ($C_{material}$ + C_{labor}) ………………………………………………………….........….Equation (11a)

Check Appendix C to review the utilization of both equations.

3.1.3 The cost of CO_2 storage

The investment cost for CO_2 storage is based on a linear equation developed by Van den Broek et al., 2010. It was modified and used by Carneiro et al., 2015 and Mathias et al., 2015. The cost for a storage site is based on developing a storage site from scratch; thus, CAPEX's cost is relatively high compared to when the storage is re-used. Therefore, the latter is also used to evaluate the storage CAPEX if an available well is re-used to overview other feasibility scenarios. Re-use wells are mainly from depleted oil/gas fields which are sometimes referred to as Hydrocarbon fields. The three references mentioned above developed CAPEX for other types of reservoirs, such as aquifers (saline aquifers) for both onshore and offshore. In this study, both onshore reservoirs are adopted to calculate the CAPEX. The cost values were treated for inflation among Van den Broek et al., 2010; Carneiro et al., 2015; Mathias et al., 2015; subsequently, all of those costs were updated to 2020 using UCCI indices

The storage cost depends mainly on the number of injection wells per site and the injectivity rate (Mathias et al., 2015). The number of injection wells is obtained by dividing the available annual CO_2 by the well injectivity (ZEP, 2011). Injectivity is defined as “the ease with which fluid can be injected into a storage medium without fracturing the formation” (Raza et al., 2015. P. 2). Thus, injectivity is the maximum amount of CO_2 (usually liquid or supercritical CO_2) that can be injected into a well. Almost all of the reviewed literature presents costing development and scenarios for fossil-based sources of CO_2 for storage, starting from at least 100 k tons of CO_2 up to 10 Mt. An exception from this literature is the base case by Laude et al., 2011 and Laude & Ricci, 2011 which presented a minimum of 45k tonne of CO_2 from the fermentation of an ethanol plant in France.

In terms of injectivity, according to ZEP, 2011, the average injectivity rate of a single well for both on-shore and off-shore storage sites is 0.8 Mt/year, with a low value of 0.2 Mt/year for onshore situations. Carneiro et al., 2015 presented the injective rate of reservoir basins/clusters for 43 locations where the minimum injectivity was 0.1 Mt/year (1 site) and maximum of ☐76 Mt/year (see Appendix B.4). Thereby, for this thesis, one well with an injectivity rate of 0.5 Mt/year is proposed for all the reservoir types and cases. Thus, every storage site has only one injection well because all of the cases have an annual mass below 400 kt CO_2.

$C_{storage}$ = n_{well} x (D_{drill} x C_d + C_w) + C_{sf} + C_{sd} …………………………………………………………….equation (12)

(Van den broek et al., 2010b) – See Appendix C.

Where n_{well} is the number of wells. D_{drill} is the drilling depth (m) starting from the ground level down to the reservoir's roof plus the reservoir thickness. C_d is the cost of drilling per meter (€/m), but C_d is equal to zero if an available well is re-used. C_w is the fixed well costs included in the drilling costs for onshore wells (€) (Carneiro et al., 2015). C_{sf} is the facilities' investment cost at the injection unit's surface, including monitoring equipment costs and installing them permanently (€). Finally, C_{sd} is the cost for site development, i.e., site investigation, drilling site preparation, and implementing Environmental Impact Assessment (EIA) (Van den Broek et al., 2010). The costs of the storage site`s components are presented in the below table and are used in equation (12) to generate the storage CAPEX.

Parameters	Unit	DOGF (hydrocarbons)	DOGF with re-use	Aquifer
Drilling cost (Cd)	€/m	2,520	0	2,520
Fixed well costs (C_w)	M€	0 [a]	0.84 [b]	0
Site development cost (C_{sd}) [c]	M€	2.77	2.77	21.4
Surface facilities cost (C_{sf})	M€	1.26	0.336	1.26
Annual O&M+M [d]	(%)/year	5	5	5
Drilling depth (H)	m	2000	2000	2000

Table 3: shows Storage components and their costs which are treated for inflation by UCCI to 2020. DOGF is the acronym for depleted oil/gas fields.
a: Cw is included within Cd, calculated for H = 3,000 meters in the reference study.
b: is the fixed cost per well for converting a production site to a CO2 storage site.
c: includes the monitoring cost prior to operation costs
d: O&M+M is the operational and maintenance cost plus the monitoring percentage to the total CAPEX.

The CAPEX of all the three types of injection sites is considered for analysis in this thesis. However, the new wells are more desired for the cost analysis to become accustomed to a whole range of new projects and to use both reservoir types for all of the cases. See the application of equation (12) in Appendix C.

3.1.4 Cost of Electricity consumption

Based on the literature review, each step of the CCS chain uses a certain amount of energy, specifically, electricity for dehydration, compression, and pumping. These costs fall under the category of annual operational costs. Therefore, these costs are sometimes covered by the fixed O&M percentage for a particular step, such as electricity for pipeline operation.

For the capture step of upgrading biogas plants, the electricity consumption is estimated at 220 kWh to produce one tonne of liquid CO_2 as given by David Hynes (see section 3.3.1b). Given the condition of the produced liquid CO_2, 19 bar, and -35 ℃, the product is ideal for truck transportation because all UBGP cases require trucks rather than pipelines. Moreover, it is assumed that these conditions are the same as conditions required for transportation by Den Hartogh (-22 ℃ and 18.52 bar).

For the compression step (at ethanol plants), based on McCollum and Ogden, 2006, to compress a certain amount of CO_2 to the outlet pressure of 15.0 MPa (preparation for transportation), a five-stage-compression is needed. The compression starts with the first stage (0.1 MPa) at a compression ratio of 2.36 until the fifth stage, where the pressure of 7.38 MPa ($P_{cut\text{-}off}$) is reached. On the other hand, pumps are used across the pipeline to booster the supercritical CO_2 to the pressure of 15 Mpa (McCollum and Ogden, 2006).

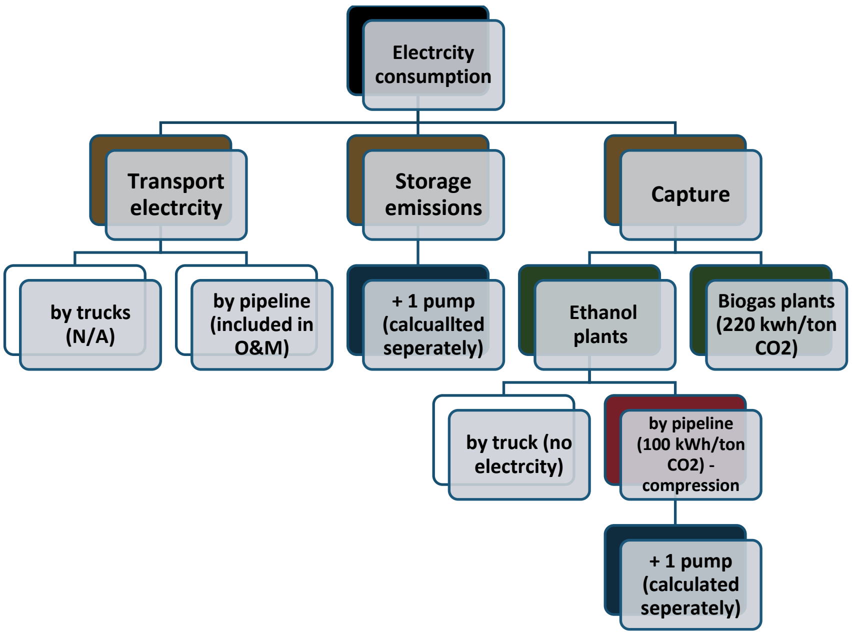

Figure 22: Simplified illustration of the overall electricity requirement and calculation

The amount of electricity required per tonne of CO_2 compressed to a 14 MPa for a five-stage-compression train was found to be 390 kJ/kg CO_2 or 108 kWh/tonne CO_2 with cooling to 50 °C. Similarly, Alhajaj et al., 2016 concluded values of 104.6 kWh per tonne CO_2 (Jackson & Brodal, 2019). Aspelund & Jordal, 2016 reported that the energy consumption for compressing one tonne of CO_2 ranges between 90 to 120 kWh. Koorneef et al., 2013 (Ecofys) reported energy consumption of 125 kWh per tonne CO_2 compression and a cost of 30 €/MWh.

Another methodology entails calculating the compressor's total power requirement proportionate to the CO_2 mass flow rate (Tonnes/day) (McCollum and Ogden, 2006) – See Appendix B.5 for the used graph. Although the calculation is based on a linear equation, it is found to be similar to the value in the previous paragraph, i.e., 100 kWh/tonne CO_2. When the Compressor power is obtained individually for every case, the annual electricity consumption is obtained by considering FHL (8760 hours).

Finally, the cost is calculated using the industrial electricity price per country. According to Statista, 2020, the costs of electricity for energy-intensive industries are divided into two categories. First, annual consumption of 500 MWh to 2,000 MWh. Second, 21,000 MWh to 70,000 MWh; However, the prices include a gap, namely > 2,000 MWh <21,000 MWh. The gap is filled by considering a separating level of 10,000 MWh; if larger, the upper range cost is used. If lower, then the lower range cost is used. It is notable to mention that the electricity costs are considered the latest and were not updated further. See Appendix B.6 for the full list.

Moreover, one pump is used to pressurize the CO_2 before the pipeline inlet; however, only for the pipeline cases only. For ethanol plants with transportation methods by truck require no pumps; however, it is assumed that the compression is made to a liquid form suitable for transportation. The power of the pump is calculated as follows.

$$P_{kW} = \left(\frac{1000x10}{24x36}\right) x \left(\frac{Q\ (P_{final} - P_{cut-off}}{\rho\ x\ \eta_{pump}}\right) \text{...equation (13)}$$

(McCollum & Ogden, 2006; da Silva et al., 2018; Knoope & Faaij, 2013) – see Appendix C

The P is the power of the required pump in kW, Q is the mass flow (tonnes/day). P_{final} *= 15 MPa &* $P_{cut\text{-}off}$ *= 7.38 MPa. P = density (840.5 kg/m*^{3}*),* η_{pump} *is pump efficiency (0.75).* It is noteworthy that the power demand depends mainly on the CO_2 mass flow, i.e., the bio plants' capacity and CO_2 density. Additionally, using this method is identical to the value of 0.44 kWh per MPa calculated by Knoope, 2015. The same pump capacity is considered for the storage part with the same costs, given that the storage part is assigned with one pump.

3.2 Data Collection (inventory of CO_2 sources & storage points)

3.2.1a Inventory of Bioethanol plants

The collection of the primary biogenic sources of CO_2 in Europe is based on searching for large bioethanol plants in Europe. However, smaller bioethanol plants were also targeted due to the overall scarcity of data. Firstly, to collect information about these plants, an excel model was developed to extract and arrange and collect the data neatly. The following criteria were used while searching for the data and registering them. See the Figure in

1. Search for ethanol production data in various units such as liters/day or m^3/year and a few others.
2. Tracking any emission-related data that's sourced from fermentation.
3. The location (or address) of the ethanol plant.
4. The type of feedstocks used in the biorefinery, and if available, the quantities too.
5. The status of the plant, whether it is under construction, operational, or shut down.

Since a complete list of ethanol plants, including required and relevant data, could not be found from the peer-reviewed literature, searching for and listing the plants was implemented individually. This means that collecting the data for each ethanol plant was performed independently by scanning the company`s profile on the official website (or an external link) or investigating the annual reports, or contacting the company directly via phone or email(s). ePURE`s (European Union of renewable Ethanol Producers) official website provides a considerate amount of helpful information about ethanol production in Europe, including an interactive map of most ethanol plants in Europe (See Appendix B.7). Eventually, a plant is enlisted in the excel sheet where sufficient amount of information about the plant is discovered.

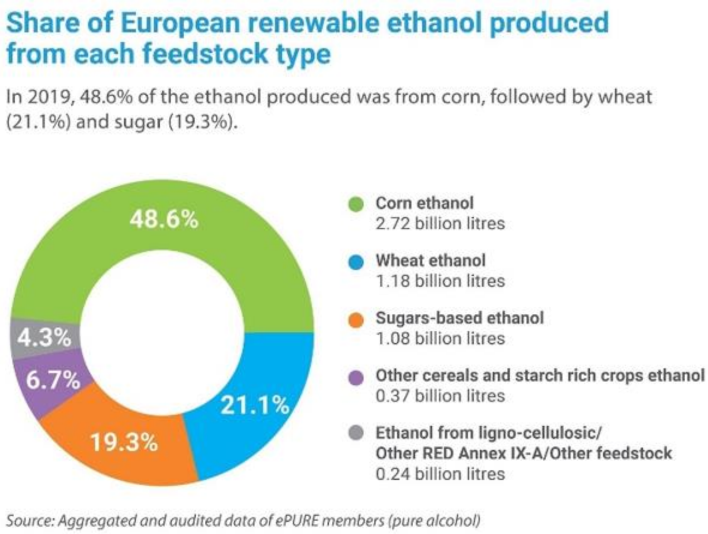

Figure 23: Ethanol production based on different feedstocks types and their shares in 2019 (ePURE [image], 2020)

3.2.1b Inventory of biogenic CO_2 from ethanol plants

As expressed in the previous section, the CO_2 is not given directly in a list; therefore, the plants' list was made by inserting them individually. Thanks to E-PRTR, some of the CO_2 and biogenic CO_2 emissions were found for some of the listed facilities. E-PRTR is the acronym for the "European Pollutant Release and Transfer Register" which is the European Environment Agency's official website (EEA), headquartered in Copenhagen, Denmark. E-PRTR provides the environment-related data registration from the industrial facilities across the European Union member states and Switzerland, Iceland, Norway, Liechtenstein, and Serbia. The registration includes annually reported data of +30,000 facilities in Europe, covering 65 economic activities within nine industrial sectors (EEA, 2020a). In addition to the E-PRTR registrations, the individual national registrations were also checked.

All the emission data reported by E-PRTR are given in 2017. However, newer data could sometimes be found on the E-PRTR`s national registration (2018, or 2019). Moreover, there were cases where the biomass-based emissions and non-biomass ones were separated like in France's registry, and sometimes not reported separately. Therefore, when the emission was given alone without indicating the source, the data is disregarded to ensure only valid biogenic data are included. The data by E-PRTR depends on reporting from the facilities at the national level or is based on specific calculations based on data from UNFCCC.

France`s data registration was the only one with proper separate biogenic/nonbiogenic emissions. Finally, while the CO_2 emissions of some of the ethanol plants could not be found directly, two simple, similar methods were used to calculate the amount of biogenic CO_2 emitted by an ethanol plant in a year.

1. The first method is based on simply proportionating the biogenic emissions to the ethanol production based on Attis biofuels, as suggested by Bernd Kuepker, Policy officer at the European commission`s Directorate-General for Energy (personal communication. October 02, 2020).

2. The second method is based on the chemical formula of fermentation presented in the theory section 2.2.1

Based on the first method, the ratio between ethanol production and emitted CO_2 is established. The equation can be reviewed in Appendix C, and some other equation with one example applied to each equation.

Applying the first method, an ideal ethanol plant that produces 50 million gallons of ethanol per annum will simultaneously produce 150k tons of CO_2 (Attis Biofuels, n.d.). The intensity of a typical ethanol plant is calculated to be 792.5 gr CO_2/liter (equation (14)). On the other hand, every 1261.8 liters of ethanol is the source of one-tonne biogenic CO_2 (equation (14a) – Appendix C). The second method also gives the proportioning of both CO_2 and ethanol productions from fermentation, chemically. Fermentation leads to a fixed amount of ethanol and biogenic CO_2. Based on the equation given by Elshani et al., 2018, the ratio of ethanol is calculated at 51.11%, while the CO_2 ratio is 48.88% to the total mass or the glucose mass (from section 1.6.1). Thus, a plant with known ethanol production/capacity with unknown CO_2 emissions can be obtained using the derived equation (14b) – see Appendix C.

At the last step, the average of both methods is used for the ethanol plants with no reported CO_2 emission. Also, for rare cases, where the reported emission is much higher than the average, then the average value is still used. This is to avoid any overestimating of the weights of CO_2.

3.2.2a Inventory of Biogas plants

The biogas plants' inventory is implemented differently from the ethanol plants because the data's availability played a more significant role in establishing a list of the biogas plants eligible for the study. The complete list of upgrading biogas plants in Europe was found from task 37 (Murphy, J. Personal communication, October 12, 2020). Task 37 is an international working group that covers the anaerobic digestion (AD) of biomass feedstocks, including agricultural residues (e.g., manure and crop residues), energy crops, organic-rich wastewaters, the organic fraction of municipal solid waste (OFMSW), and industrial organic wastes" (IEA bioenergy, 2019. About task 37). However, the list did not provide the required information about the emissions of Carbon Dioxide from AD. Therefore, several steps of calculations and assumptions were needed to calculate the emissions data. In the following two sub-sections, an elaborate explanation of the methodology is presented.

3.2.2b Inventory of biogenic CO_2 from biogas plants

The capacity of an upgrading biogas plant is given in Nm^3. Nm^3 refers to a Normal cubic meter for gases at 0 °C and pressure of 1 bar (atmospheric pressure) (Ulrich & Vasudevan, 2006; Schovsbo et al., 2014.). Since the capacities of both methane and raw gas were given for most of the plants in the list, the ratio of the CO_2 was found. Raw biogas contains Methane, CO_2, and traces of some other impurities such as H_2S (0 – 4000 ppm) and Nitrogen around 0.2% (Petersson & Wellinger, 2009) - See Appendix B.8 for the composition for biogas composition compared to natural gas. These tiny fractions of impurities can be neglected for simplicity. Therefore, the residual gas is assumed to be 100% Carbon Dioxide. Also, both raw gas and biomethane flow rates were assumed to be flowing at 100% capacity design since most upgrading biogas plants use almost the full design capacity (Jeroen Driessen, January 14, 2021, Personal communication).

Given the limited timespan of this research, it was decided to collect data for the largest 15 to 20 biogas plants regardless of their geographical location. First, A few criteria were used to identify those largest plants; after some parameters were applied to the list.

1. An operation factor of 85% was applied to a Full Load Hours (FHL = 8760 hours) for the flow rate, as suggested by Jerry Murphy, the leader of task 37 (Personal communication, October 12, 2020). Jan Liebetrau, head of consulting and research at Rytec GMBH, suggested a factor of 83% based on an analysis by DENA (Deutsche Energie-Agentur or German Energy Agency) (personal communication, January 14, 2021).
2. A recovery factor was applied to the final annual volumes of CO2 by the type of each of the technologies, as Jeroen Driessen suggested, the global sales manager of biogas at Pentair (personal communication, January 14, 2021).

1. Technology	CO_2 recovery factor
Chemical scrubber	89%
Pressure Swing Adsorption (PSA)	89%
Water scrubber	50%
Organic physical scrubber	89%
Membrane	89%

Table 4: CO2 recovery factor as per J. Driessen. Source of the technologies: task 37

3. The annual volumes of CO2 were converted to masses using the CO2 density (ρ) at the Normal conditions since Nm3 is in Normal conditions. The density of gaseous CO_2 at Normal conditions (DIN 1343) is 1.9772 kg/m3 (Matheson, n.d.), and it is 1.976 kg/m (Mets et al., (IPCC), 2005). The majority of the websites, mechanical applications, and instant converters use the first value. Different values are also used in some of the resources; however, they are all very similar, and the difference can be neglected. Moreover, the Normal conditions by DIN 1340 standard are the same as STP (Standard Temperature & Pressure), both at 0 °C and 1 ATM (see Appendix B.9).
4. As the last step, the plants were filtered for their annual contribution to CO_2 masses to be analyzed for CCS. As a minimum level, the value is set at 10,000 tons per year, as Jeroen Driessen advised (Personal communication, January 14, 2021). This was also justified by the transportation results, especially for the pipeline, which is highly cost-ineffective.

3.2.3 Inventory of potential geological storage

This section entails identifying storage points (locations) for the CO_2 masses surveyed from both ethanol and biogas plants to be stored. The majority of the pieces of literature that addresses the CCS chain and analyze economic feasibility assume a virtual storage point(s) at a particular location (Mechleri et al., 2017, Laude et al., 2011, Xu et al., 2010, Da Silva et al., 2018, and others). A robust analysis of actual geological storage points would require a completely different independent study; however, in this study, the storage points were constructed based on GIE underground storage and the hypothesis of Europe`s fertility land, which is elaborated on in theory in section 2.2.6.3. In the following paragraphs, the European lands' fertility to establish CCS projects is briefly presented to justify the hypothesis and the methodology of storage points in this research.

Global CCS Institute provides a simple interactive map to indicate the potentiality of the EU countries to develop CCS storage projects based on:

1. Potentiality of the country`s land for storage geologically
2. Maturity of their evaluation and progress in developing injection sites.

Given that the highest indication is for Canada 98, Norway and the US come second at 96, the rest of the world has almost non, except Brazil and Mexico in the Americas(86, 61), Australia (86). From Africa, Algeria (63) and South Africa (42), while in Asia, China (91), Saudi Arabia (79), India (48), and a few others. Therefore, the potential storage indicator for the EU is promising for the majority of its lands, for instance, Germany, France, Poland, UK, Spain, The Netherlands, Hungary, Austria, Denmark, and a few others (Global CCS Institute, 2019) - see Figure 24, Left.

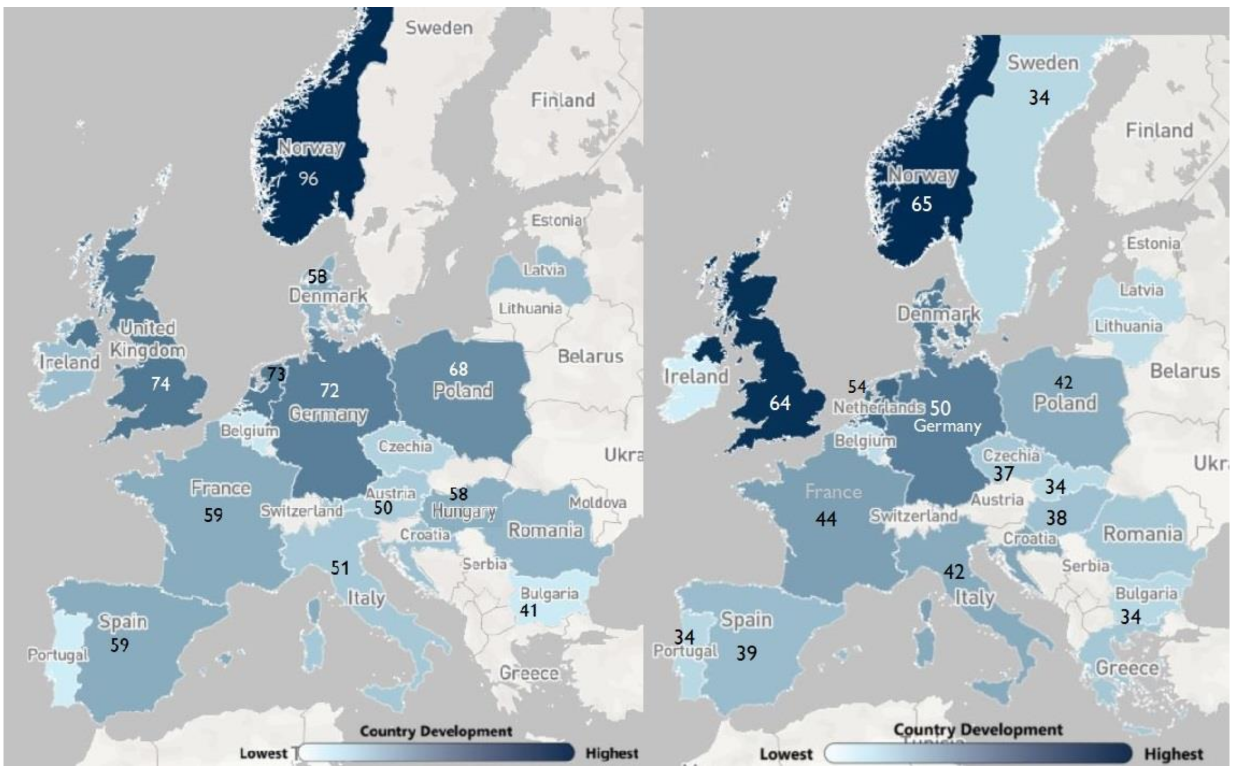

Figure 24 left: Potential storage indicator. Only the region of Europe included with a range of (40 – 100). By Global CCS Institute, 2019 (database for storage indicator)
Figure 24 right: CCS readiness indicator. Only the region of Europe included and only the range of (35 – 100). By Global CCS Institute, 2018 (database for storage indicator).

Another factor that was taken into account is the country`s CCS readiness Index (RI) which evaluates the EU members in terms of:

1. Country`s requirement of CCS
2. Country`s law and regulation and its policy inclusion of CCS
3. Storage resource development

The RI actively traces and monitors the countries with higher readability to incorporate commercially viable CCS (Global CCS Institute (RI), 2019). Setting Norway and UK as the basis, it was concluded that some of the EU states are somewhat suitable for CCS projects potentially (see Figure 24, right). At least the countries where most ethanol and UBG plants of this thesis are located, such as Germany, France, the UK.

As a next step, the storage locations were constructed based on gas storage points distributed in Europe. Gas Infrastructure Europe (GIE) provides an interesting map with its rooting excel sheet for existing and under construction underground storage facilities in Europe. The map and the excel format provide comprehensive data about these storages with their working gas volume (Storage capacity), withdrawal and injection rates, in addition to many other indicators (GIE, 2018). Eventually, Based on the reservoirs' geographical locations, Each of the ethanol cases is connected to one storage point. In contrast, one storage point is utilized for all the UBG cases to minimize the storage costs and construct a realistic design since the contribution of biogenic CO2 from individual UBG plants is modest. See Appendix D.9 for the complete storage points chosen.

3.2.4 Establishment of the routes & Creation of the interactive map

Mapifator was used to connect each bio-plant to its storage reservoir(s). Mapifator is online software that can be used to generate interactive maps with real-in coordinates, roads, geo-sites and is used mainly to pin customized markers as preferred (see Appendix B.10 for the software`s interface). The pinpoints can be inserted using an actual address or geographical coordinates with practice as accurate as google maps.

The following steps are conducted to make the interactive map of the CO_2 sources and their assigned storage points after an account with limited features was registered.

1. Each ethanol and biogas plant and storage point were inserted using either their address, coordinates or the postcode, or the street name where the facility is located. These were sourced individually from various websites (official or external).
2. Different pins were generated and assigned to each type of the pinned point.
1. With the add-ons feature, the shortest road routes were generated automatically by the software and were further checked with google maps to authenticate the routes and the given distances.
2. The shortest route distance given by both Mapifator and google maps is based on driving a vehicle on the highways or the roads. The exact distance is counted for the returning freight even though some routes could be longer or shorter due to the traffic or due to entering or leaving a highway/road.

3.3 Transportation methods

3.3.1 Transport by road tankers

It was found in the reviewed literature that almost all of them implement transportation using either ships or pipelines or an intermodal method. This is because the largest share of works of literature present CCS for fossil-based facilities like natural gas power plants, oilfields, or coal-fueled plants that have large CO_2 footprints. When a plant has at least 0.5 MT of annual emissions, it is incredibly challenging to transport these large amounts of CO_2 by trucks. However, all the cases in this thesis had an annual mass of less than 0.5 MT; therefore, road-based transportation was investigated too. For this purpose, many companies like Asco CO_2, Linde gas, Ocap, Van Hool (Belgium), and Messer group were directly approached to consult the mechanism of transporting CO_2 by trucks and their associated costs. It was intended to collect information about real-time prices and the procedure of truck transportation. Eventually, the preliminary information and data were collected from Wouter Vis (logistics planner-Den Hartogh), and more detailed data were collected from Jan Halin (Commercial manager- Den Hartogh) via an online interview. See Appendix B.11 for a short overview of the company.

According to Jan Halin, the common condition of CO_2 by truck transportation is in liquid form at -22 °C, and pressure of 14 to 15 bar (personal communication, January 12, 2021). However, at this state, CO_2 is still in the gaseous phase theoretically, as indicated by CO_2 calculator software by EMS energy institute (Zhao, 2021). Therefore, these values are placed a bit higher of -22 ° C & 18.52 bar where CO_2 is in a liquid phase and has a density of 1040.8 kg/m^3.

When CO_2 is compressed to different pressure and temperature, its physical phase and properties change (see Figure 26) because it is a gas at normal temperature and normal pressure (IPCC, 2005). Finally, the CO_2 phase of all the cases was changed from the gaseous (ρ =1.9772 kg/m^3) phase to the liquid phase at a density of 1040.8 kg/m^3 (See equation (15) in Appendix C).

The transportation tankers utilized by Den Hartogh for liquid CO_2 have a capacity of 22,000 kg (see Figure 25a & 25b). Thus, one full load transports slightly more than 21 m^3 of liquid CO_2, and

Figure 25a (below): transportation tank for liquid CO_2 manufactured in 2020. Source: Halin, J., 2021. Personal communication
Figure 25b (above): A transportation trailer on the roads. Source: Den Hartogh.com

for transportation of 59,000 (case #11) tons of CO_2 per year, around 127 shipping per year would be needed or 2.4 trucks per week. The list of the plants with their estimated volumes and transportation parameters is presented in the results section.

It is important to note that the loading pressure is around 14-15 bars with a maximum allowable pressure of 22. The tanks are always equipped with safety valves and are given safety parameters since CO_2 has a holding time, which in this case, is around 100 days. The tank also has a double layer with internal storage, and the outer layer ensures a suitable pressure in case of leakage (Halin, January 12, 2021. personal communication).

Holding time is a general characteristic of liquified CO_2, where its initial pressure (in liquid phase) builds up more pressure over time. When this accumulated pressure reaches the maximum of 22 bars, the extra pressure would need to be released via a safety valve, and the released gas not toxic nor flammable (Halin, January 12, 2021. Personal communication).

3.3.2 Transport by pipeline

The first elements to be determined in a pipeline design are the trajectory path and its total length. Assessing and evaluating various possible routes is substantial to optimize the final route in terms of distance, obstacles, the Right-Of-Way (ROW), and most importantly, the costs (Peletiri et al., 2018). However, in this study, the exact distances used in the road trucks' transportation method were used for the pipeline method. This is for the sake of simplicity and provides an exact comparison between both the method for economic feasibility. Again, almost all of the reviewed literatus assume the length of the pipeline based on arbitrary assumptions except for Van den Broek et al., 2010. The latter examines the pipeline trajectory for topographic variations across the pipeline route because the type of model used to estimate the pipeline cost depends substantially on the terrain type.

In the following sub-sections, the main characteristics of the pipeline and the physical and chemical properties of Carbon Dioxide are presented. Also, the main software is used to design and calculate the features of the pipeline and CO_2 concurrently.

Pipe Flow software (PF) and its properties

In order to calculate various characteristics of the pipeline design, such as the pipe diameter, velocity, pressure drop, etc., the Pipe Flow software (PF) was used to ease the calculations and generate the data where needed. PF software works in parallel with the web-based tools, where each of them can be used interchangeably. The software resolves fluid mechanics problems with simple to medium complexity, specifically in fluid motion and fluid dynamics (Savović, 2021). The main resolutions that PF provides, which were used for this study, are Pressure drop & flow rate, pipe diameter, flow velocity, Reynold number, and some others, which were calculated implicitly. However, excel formats were also used to double-check values. See Appendix B.12 to review the main interface of the software.

3.3.2.1 Technical characteristics & pipeline design

For a pipeline design, it is essential first to identify the fluid's main characteristics, which is, in this case, Carbon Dioxide. The CO_2 stream must be first purified, conditioned, and pressurized to the designed pressure (Serpa et al., 2011). In the following subsections, the main properties of CO_2 and the technicality of the pipeline are presented. It is important to note that for the pipeline design, the same distances used for the truck transportation are used as mentioned in section 2.1.4. Thus, the routes are the shortest road routes chosen by the web tool (Mapifator), following the google map's same standard.

3.3.2.1a Identifying & setting the properties of CO2

In this study, the operation phase of CO_2 by pipeline is dense or as widely recognized as the supercritical phase. The common practice and experience of transporting CO_2 in dense phases over long distances are well matured in Europe (Buit et al., 2009 (CO2Europipe). Additionally, transporting CO_2 in the supercritical phase where the density is high and the viscosity is low is traditionally preferred due to efficiency and economic feasibility (Mechleri et al., 2017). The supercritical phase is the dense phase of CO_2 and some other gases, where it has the combined features of both gas and liquid phases (Moshfeghian, 2012). Among the papers where CO_2 is designed to be transported in supercritical phases is Gao et al., 2011 (China), IPCC 2005, Buit et al., 2009; Ros et al., 2014; and many others.

The minimum and maximum pressure are bound by the fluid's physical characteristics that must stay within the decided phase (see Figure 26). Nevertheless, the peak limit where CO_2 remains in the supercritical phase is up to 800 ℃ and 8000 Bar (Zhao, 2021 "CO_2 calculator"). This is based on the Span–Wagner equation of state covering the fluid region starting from the triple-point up to 826 ^{o}C and pressures up to 8000 Bar. On the other hand, the lower values of supercritical CO_2 are ≥ 30.98 ℃ (31 ℃ for simplicity) and a pressure ≥7.38 MPa (Dostal et al., 2004; Schoots et al., 2011).

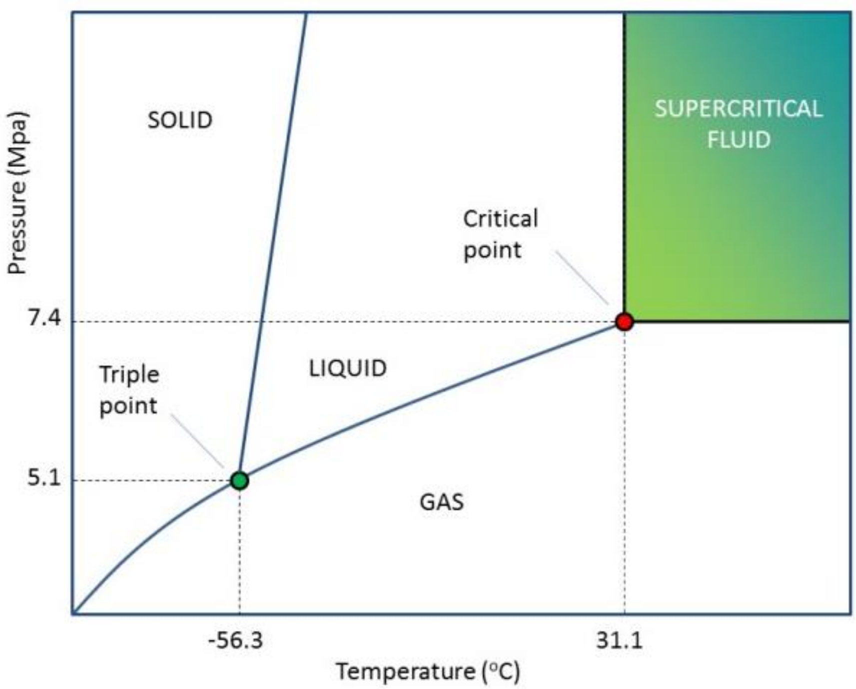

Figure 26: Illustration of CO2 phases depending on the temperature in °C (x-axis) and pressure in MPa (Y-axis) retrieved from http://www.suprex.uk/supercritical-co2

The most common pressure chosen for the supercritical phase CO_2 found in the literature was around 15 MPa. Regarding the temperature, it ought to be above 31 ℃. At these conditions, the density is found to be 840.8 kg/m^3 according to the CO_2 calculator by "EMS energy institute" (Zhao, 2021), and it is 840.3 kg/m^3 according to webtool "Peace Software" (Wischnewski, 2007).

Hence, the average of the two values (840.5 kg/m^3) is used in this study's pipeline calculations. Other parameters necessary to complete the pipeline design using the PF software are listed in a table in Appendix B.13

No	Studies	Inlet pressure	Outlet/min pressure	Temperature
1	Barrie et al., 2005	21 MPa	7.4 MPa	> 31 °C
2	Kang et al., 2014	15 MPa	8.5 MPa	13 °C to 44 °C
3	ZEP, 2011	60 Bar (6 MPa)	Not given	10 °C
4	Van den Zwaan et al., 2011	150 Bar	100 Bar	> 31 °C
5	Chandel et al., 2010	13 MPa	10 MPa	27 °C
6	Serpa et al., 2011	150 Bar	85 Bar	12 °C to 44 °C
7	Gao et al., 2011	15.2 MPa	10.3 MPa	14 °C
8	Patchigolla & Oakey, 2013	15 MPa	10 MPa	15 °C to 30 °C
	Perez et al., 2012	1.5 MPa	0.7 MPa	-50 °C
	This thesis	**15 MPa**	**7.5 Mpa**	**31 °C or higher**

Table 5: Various inlet/outlet pressure and temp. From some papers.

3.3.2.1b Flow velocity & pipe diameter (V & D)

Both pipe diameter and fluid velocity are usually determined first, as demonstrated in the literature such as in Vandeginste & Piessens, 2008; Serpa et al., 2011; Wojnarowski et al., 2019, and many others. However, there are certain limits for the velocity, which elects it to be decided first. On the other hand, the pipeline diameters of this study's cases are mostly smaller than traditional pipelines used for fossil-based CCS projects. According to Peletiri, 2018, the minimum internal diameter (ID) of existing pipeline projects in various regions in the world is at least 152 mm (☐ 6")[5]. On the contrary, pipeline diameters of the cases in this study have diameters up to 6". Thus, it was more suitable to determine the velocity first. Velocity can be calculated using equation (16) as given by Peletiri et al., 2018.

$$V = \frac{4\,Q}{\rho\ \pi\ ID^2} \quad \text{equation (16)}$$

Where V is the flow velocity (m/s), Q is the mass flow (kg/s), ID is the internal diameter, and ρ is the density (kg/m^3).

According to Knoope et al., 2013, the flow of liquid CO_2 in the pipelines should not exceed 6 m/s to avoid damaging the pipe by vibration and/or erosion. For the minimum limit, the flow should exceed 0.5 m/s to ensure proper flowing. For cost optimization consideration, the optimum velocity is 1-2 m/s for liquid CO_2 and 5-15 m/s for gaseous CO_2 (Knoope, 2015). Another point of consideration for velocity is the erosional limit that should be avoided not to cause damaging the pipe, higher loss in the pressure, and noise (Nazeri et al., 2016). The erosional velocity is calculated using a formula given by API RP14E (American Petroleum Institute 1991).

$$V_e = \frac{\sqrt{8\ x\ \omega}}{\sqrt{fD}\ x\ \sqrt{\rho}} \quad \text{equation (17)}$$

(Mechleri et al., 2017)

[5] See Appendix B.14 for the listed projects by Peletiri et al., 2018.

Where V_e is the erosional velocity, f_D is theDarcy friction factor (0.013 in Mechleri et al., 2017), and in this thesis, 0.02 is used. ω is the shear on pipe = 40 Pa. ρ is CO_2 density (840.5 kg/m). Using equation (17), it found that the erosional velocity is 4.36 m/s. At the lower densities, where the flow loses pressure down to 7.5 MPa, the erosional velocity is 5. m/s, given the density decreased to 614 kg/m^3 (Zhao, 2021 (CO_2 calculator). Gao et al., 2011 used supercritical phase CO_2 for pipeline transportation between 10.3 MPa to 15.2 MPa with a flow velocity of 1.36 m/s.

Regarding the pipe diameters, it was maintained that the velocity would not reach 4.36 m/s. Diameter is calculated by equation (18) by IEA, 2005 as cited in Vandeginste and Piessens, 2008.

$$ID = \sqrt{\frac{4\ x\ Q}{\mathrm{V}\ x\ \pi\ x\ \rho}} \qquad \text{equation (18)}$$

Where ID is the inner diameter of the pipe (m), Q is the mass flow (kg/s), v is the velocity (m/s). The Q_{mass} is obtained by dividing the annual available CO_2 mass by (365x24x3600 seconds). See Appendix C, where the case of CropEnergies AG – Zeitz, Germany is applied to in the formula.

3.3.2.1c Pressure drop (ΔP) & booster pumps

Following the physical properties and the general laws of flow, CO_2 pressure across the pipeline trajectory decreases due to the friction of the pipe's walls (frictional pressure loss). The loss of the initial pressure depends on some factors such as pipe diameter, overall design of the pipeline, sort of the materials used, and also the flow velocity (Serpa et al., 2011). Another essential factor influencing the pressure drop is the ground elevation change (symbolized with h or z in the literature) where the pipeline is located. However, the pipe elevation is not considered in this study; this means that $h_1 = h_2$ or $h_1 - h_2$ = zero.

Pressure drop depends highly on the pipeline diameter and pipeline length because, in the absence of an elevation factor, a smaller diameter increases the friction and thus reduced the pressure. Pipeline length influences the pressure drop similarly, yet its effect is smaller than pipeline diameter (Serpa et al., 2011; Vandeginste & Piessens, 2008). The value of pressure drop is expected between the minimum and maximum pressure (P_{max} or P_{inlet} and P_{min} or P_{outlet}) designed not to be exceeded (Peletiri et al., 2018). There are several methods to calculate the pressure drop using similar yet distinct formulas. For instance, PF software used equation (19) to calculate the pressure drop, which takes several factors into account as flow rate, pipeline length, density, pipe diameter, etc.

$$\Delta P = \frac{8\ x\ \rho x\ f_D\ x\ \ L\ x\ \mathrm{Qv}^2}{\pi^2\ \ x\ ID^5} \qquad \text{Equation (19)}$$

Where ΔP = pressure drop ($P_1 - P_2$) (Pascals), Qv = volumetric flow rate (m^3/s), f_D = friction coefficient or as famously known as the Darcy-Weisbach friction factor (Knoope, 2015). In this work, the same factor of 0.015 was calculated and used for all of the cases. L = length of pipeline (m). ID = internal diameter (m) (Savović, Z (PF), 2019). Other methodology entails calculating specific or actual pressure drop (Pa/m) by Van den Broek et al., 2010b.

$$\Delta P_{per\_meter} = \frac{8\ \lambda\ \mathrm{Qv}^2}{\pi^2\ \rho\ ID^5} \qquad \text{Equation (20)}$$

Where ΔP_{per_meter} is the pressure drop per meter (Pa/m), λ is the friction coefficient, 0.015 is used in the reference paper. ID is the pipe's internal diameter (m). since the pressure is not allowed to decrease below 7.5 MPa, booster pumps are installed across the pipeline to boost the pressure back to 15 MPa. The compressed CO_2 is kept over the pressure of 7.5 MPa to preserve the supercritical phase of CO_2 and prevent the two-phase flow from occurring (Pissens et al., 2008). Da Silva et al., 2018 used 8 MPa following the same principle. Equation (21) demonstrates the length at which a booster pump is required to be installed.

$$L_{pump} = \frac{P_{cut-off}}{\Delta P_{\_m}/(1000\ km)} \qquad \text{Equation (21)}$$

Where L_{pump} is the pipeline length at which the booster is installed (km), and $P_{cut\text{-}off}$ is 7.5 MPa. Subsequently, the number of the required pumps and the pressure at the final stage (P_{end}) is determined using equations 21a and 21b (See Appendix C). Pressure drop could also be calculated using the PF software[6]; however, it requires the cases to be inserted individually. Finally, how the pumps work to boost the pressure of the supercritical CO_2 back to above 7.5 MPa is illustrated in Figure 27.

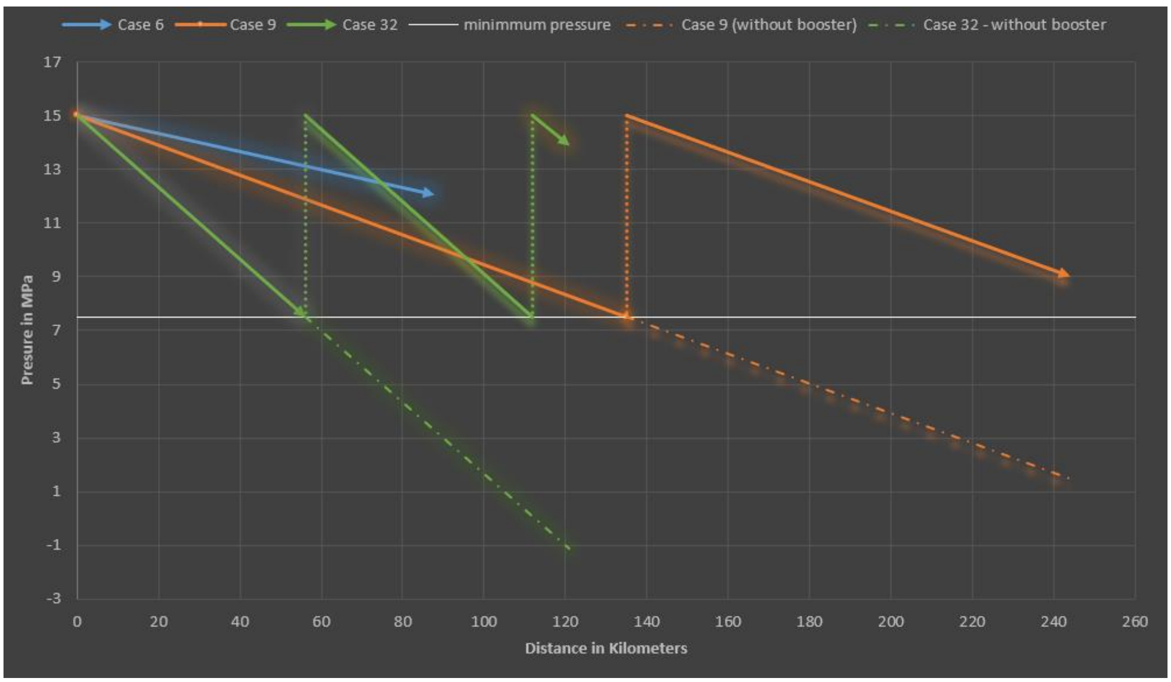

Figure 27: Illustration of the pressure drop and booster pumps' work on boosting the pressure of the supercritical CO2 back to over 7.5 MPa. The pressure drop is increased for the sake of simplicity and clarification by using the friction factor of 0.02 instead of 0.015. Case #6 (blue line): arrives at the destination without needing extra boosters. Case #9 (orange line): requires a booster at km 135. While case #32 (green line): requires two boosters at intervals of 56 km each before reaching the destination. All the cases require a booster at the capture site to escalate the pressure from 7.5 MPa to 15 MPa.

3.3.2.1d Friction factor & Pipe roughness

From equations (19) and (20), it can be noticed that pressure drop depends to some degree on the friction factor of the pipe, which is famously known as the Darcy-Weisbach friction factor (f_D).

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[6] See Appendix B.15 for the pressure drop interface by PF software

The Darcy friction factor is calculated by both equations (22) and (17) from Mechleri et al., 2017 or directly from equation (21a) by Element energy, 2010.

$F_D = 4 \times f_F$ …………………………………………………………………………………………………Equation (22)

f_F is the fanning friction factor based on the Cole-brook-White equation (Mechleri et al., 2017).

$$\frac{1}{2\,x\,\sqrt{f_F}} = -2\,x\,\log\left(\frac{\mathcal{E}/ID}{3.7} - \frac{5.02}{Re}\ x\,log\left[\frac{\mathcal{E}/ID}{3.7} - \frac{5.02}{Re}\ x\log\left(\frac{\mathcal{E}/ID}{3.7} + \frac{13}{Re}\right)\right]\right) \text{……………. Equation (23)}$$

Where ID is the internal diameter in mm, ε is pipe roughness (0.04 mm, see table 9.0). Re is Reynold's number calculated as follows.

$$Re = \frac{\rho\ x\ V\ x\ ID}{\mu} \text{…………………………………………………………………………………… Equation (24)}$$

Where ID is the internal diameter in m, V is flow velocity (m/s), and μ is viscosity (Pas) (Peletiri et al., 2018).

$$f_D = \frac{1.325}{\left[\ln\left(\left(\frac{\varepsilon}{3.7xID}\right)+\left(\frac{5.7}{Re^{0.9}}\right)\right]^2\right)} \text{………………………………………………………………………….Equation (22a)}$$

Where ID is the internal diameter in mm, and for pipe roughness, 0.04 mm is used. While for Re, 1028700 (case #1) is used. It is essential to mention that the outcomes from both equations (22) and (22a) are similarly 0.015 which is interestingly the same friction factor used by IEA, 2002 (IEa GHG, 2002 cited in Piessens, 2008). Review the pipe roughness in various literature in Appendix B.16.

3.3.2.1e Pipe wall thickness

One of the critical factors to consider in designing a pipeline is its wall thickness, affecting the material cost and making it expensive if it is overestimated. On the other hand, if underestimated, thinner wall thickness causes fractures and crack propagation in the pipe (Knoope et al., 2013). Wall thickness of the pipelines of all cases was calculated using equation (25) by Mccoy & Rubin, 2008.

$$t = \frac{P_{max}\ OD}{2\ S\ E\ F} \text{…………………………………………………………………………………………Equation (25)}$$

Where t is the wall thickness (mm), P_{max} is the maximum operating pressure of 15 MPa. OD is the outside diameter in mm, E is the longitudinal joint factor (1.0). F is the safety design factor (0.72), and S is the specific minimum yield stress of the pipe material, which in this study is 240 MPa for carbon steel ASTM A-106 Gr. B is 240 MPa (ASTM international, 2014)

Gobinda Mixed metals B.V. suggested two pipe types: carbon steel ASTM A-106 Gr. B and Stainless steel ASTM A-312 TP 304L (Van der Mijn. Personal communication. February 25, 2021). However, only Carbon steel is considered for this research since all kinds of literature favor carbon steel because it is much cheaper than stainless steel and can still assure appropriate quality. The design factor can be chosen according to the population's density in the area where the pipeline is located. Knoope, 2015 used the factor of 0.5, while Peletiri et al., 2018; McCoy & Rubin, 2008; and Mechleri et al., 2017 used the design factor of 0.72.

3.4 Abatement costs and economic attractiveness of the cases

As described in theory, in sections 2.2.1, the abatement costs are calculated using the MACC formula. The components of the formulas include mainly the capital costs, annual cash outflows (O&M), and cash inflows (profits or benefits), capital recovery factor (α), and most importantly, the abated emissions. MACC is used solely to determine at what cost the biogenic emissions can be abated to achieve negative emissions in the EU. However, additionally, it is assumed that the sequestered CO_{2_bio} can be traded in the carbon market from 2025 onwards. In this regard, the NPV (as described in section 2.2.2) is used to evaluate whether the cases are profitable.

It is assumed that implementing CCS is rewarded with credits and is covered under EU ETS incentives from 2025 to encourage the negative emissions technologies and help Europe to reach its targets by 2050. Thereby, each sequestered tonne of biogenic CO_2 can be traded in the carbon market. Another support for such investment can be subsidies from the European Commission, national governments in Europe, or fund support from an independent organization.

The carbon market in Europe is currently at its highest, around 43 €/tonne CO_2, even after the corona Pandemic in 2020 (Ember, 2020; Mathis W., 2021) – see Figure 28 left and right. However, there are uncertainties regarding the future of carbon prices depending on the political-driven policies, incentives, regulations. The second factor is the correlation between stock prices and carbon prices, which change daily and by market forces (Ivan Flores (NEA). Personal communication. April 07, 2021). On the other hand, carbon prices are thought to reach above 100 €/tonne by 2030 and maybe even higher, according to Johannes Bollen, an Environmental economist at CE Delft (Personal communication. April 02, 2021).

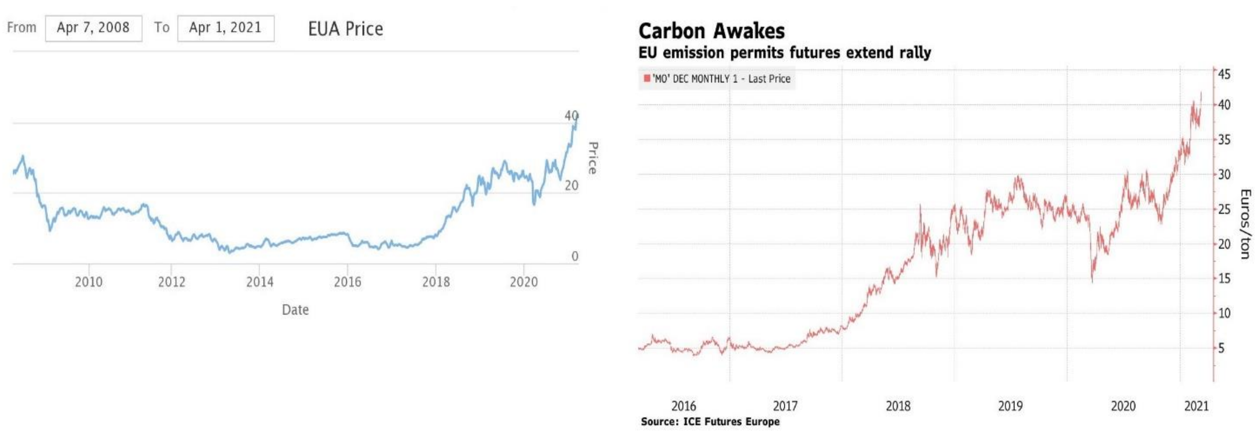

Figure 28 (left): Carbon prices €/tonne CO2 since last decade. Source (Ember, 2020).
Figure 28 (right): EU carbon prices from 2015 to 2021. Source (Mathis W., 2021 cited from ICE futures Europe).

Finally, the cost of carbon allowance or the penalty to exceeding the cap limit, an emitter had to pay 40€ (2005 to 2007), or 100 € per every tonne of CO_2 since 2008 (Bayer and Aklin (PNAS), 2020).

The carbon price) This study is assumed to be at a range of 50 € to 100 € per tonne CO_2 in the EU ETS Market. Hence, both high-end and lower-end values are used to evaluate the BECCS system's economic performance designed for each of the cases.

Most of the literature adopted a discount rate of 10% depending on the project type and project lifetime regarding the discount rate. Koornneef et al., 2012, for instance, used 10% and 30 years lifetime for many plant types with CCS. Usually, from a private-perspective analysis, a project's attractiveness is based on higher discount rates where the project lifetime becomes irrelevant. While from a social-perspective analysis, usually a discount rate of 4-6% is used in industrially developed countries. Moreover, from a climate-change perspective, there are incentives by the policymakers and governments to use discount rates as low as 2% can be used (Blok and Nieuwlaar, 2017). In this study, a social discount rate of 4% and a private discount rate is used for sensitivity analysis.

3.5 Greenhouse Gas (GHG) emissions from the CCS chain

Calculation of abated biogenic CO_2 emissions depends on the annual biogenic emissions and the GHG emissions produced from constructing or installing the CCS units in addition to their annual operation and maintenance emissions. The amount of CO_2 generated from applying CCS on ethanol and biogas plants is computed separately per each of the three steps, i.e., capture, transportation, and storage. Each of these steps accounts for a particular amount of GHG emissions that did not exist prior to implementing the CCS units. Therefore, these new emissions are referred to as CCS GHG emissions and are subtracted from the total annual biogenic emissions sequestered per case.

The emissions inventory for the CCS chain is divided into two scopes. Scope 1 includes mainly the one-off emissions associated with constructing the specific unit required to process the commodity at this step which CO_2 is the substantial portion of it. Scope 2 includes mainly the annual GHG emissions associated with the energy consumption generated from operation. Maintenance is thus considered within the operation, or its small magnitude is disregarded.

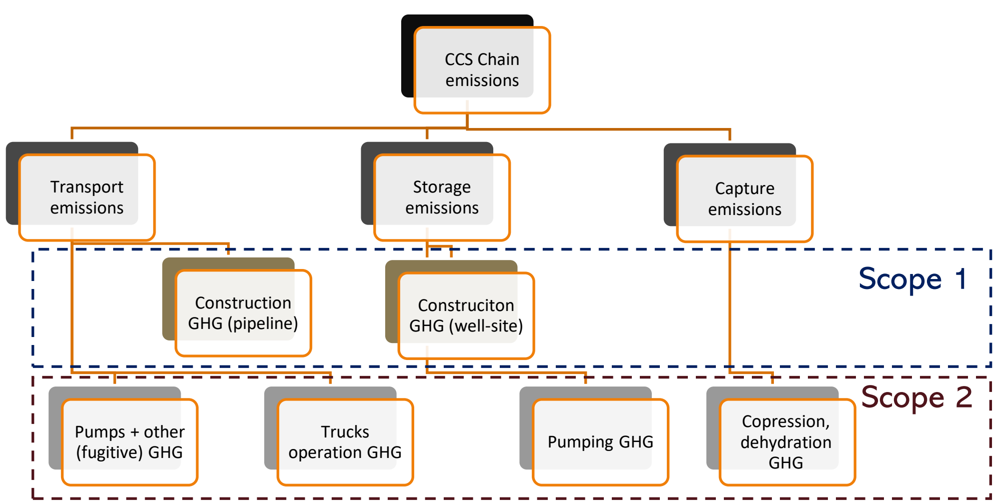

Figure 29: Illustration of GHG emission considered in this study (CCS chain)

3.5.1 GHG emissions from the capture stage

As stated in the previous sections, the steams of CO_2 from ethanol and biogas plants are considered pure and ready to be conditioned. Therefore, only compression and dehydration operations are required prior to transportation. Hence, the amount of CO_2 emitted is related to the energy consumption (electricity) that was used in the compression train(s). It is important to note that this thesis does not approach the full chain GHG from the beginning, i.e., the emissions associated with farming the feedstocks, cultivation, and feedstocks transportation to the biorefineries. Only the amount of available biogenic CO_2 from both ethanol (fermentation) and biogas plants (AD and methane upgrading) that are already in operation are calculated.

For the capture step, only the electricity consumed during the compression process is considered. The amount of GHG emissions is calculated using the CO_2 emission intensity (g CO_2e/kWh) per plant`s political location, using the country's intensity rate. Additional to compression, for the cases where a pipeline is used for transportation, the pumps' electricity usage is also considered.

Regarding the CO_2 emission intensity, the dataset of electricity generation intensity in 2019 by EEA is used. For instance, France's electricity intensity is 52 g CO_2e/kWh, 207 in Germany, 431 In the Czech, and 287 in the EU-27 (EEA, 2020b) – See Appendix B.17 for the electricity-CO_2 intensity. As an average, the European union's carbon intensity was 269 g CO_2 in 2018 (IEA, 2020b).

3.5.2a GHG emissions from the road transportation

In their paper “Measuring and Managing CO_2 Emissions”, McKinnon & Piecyk, 2010 presented average emissions factors for each transportation method. The emission factor advised for truck transportation is 62 g CO_2/tonne-km (McKinnon & Piecyk, 2010). Moreover, the emission factors change according to the trip's percentage that the truck is driven empty. Considering that the truck departs full-load from the point source to the storage site and returns empty, the percentage of truck-km run empty is 50%. The emission factor in this sense is then 77.2 g CO_2/tonne-km considering a load of 22 tonnes. For a 0% driven empty, the emission factor is 45.3 g CO_2/tonne-km for the same load (McKinnon & Piecyk, 2010). Pootakham & Kumar, 2010 proposed an 89 g CO_2/m^3-km for a truck-trailer with 30 m^3 capacity, which corresponds to 65 g CO_2/tonne-km for the truck of 22 m^3 proposed in this study. On the other hand, the emission factor reported by the Association of European Automobile Manufacturers (ACEA) for the newer trucks from 2019 presents lower emission of 56.5 g CO_2/tonne-km on average.

Thereby, the emission factors of 77.2 g CO_2/tonne-km are used both ways, given that one way is full-load and the other way is empty. See Appendix B.18 for the complete range emission factors for all the loads.

3.5.2b GHG emissions from pipeline transportation

Regarding the GHG estimation for the pipelines, the values were collected from an assessment study for a gas line project in Australia (Katherine to Gove Gas Pipeline) in 2013, reported to the Environmental Protection of the Northern Territory Australia (NT-EPA). The study carefully estimated the GHG emissions for the project based on three scopes. The GHG values were given for the whole period across the project construction and the route length of 603 km. Therefore, the GHG values were distributed over the distance to obtain the GHG emissions per 1 km. Given the study`s pipeline diameter (300 mm - 12” NPS300) in comparison with the pipeline diameters in this study (max 6”), most of the emission factors were adjusted by half. However, some of the values were kept the same such as the pipe commissioning and decommissioning.

Activities	6”NPS150	5”NPS125	4”NPS100
	GHG emission kg CO_2-e (Scope 1 + Scope 3) per km		
Grading, trenching, pipe-laying, backfilling (Scope 3, scope 1)	20,431 1,551	20,431 1,551	20,431 1,551
Transportation of pipeline sections (Scope 3, scope 1)	945 75	945 75	945 75
Operate construction camps (Scope 3, scope 1)	3458 264	3458 264	3458 264
Fuel haulage (Scope 3, scope 1)	224 17	224 17	224 17
Transport of camp infrastructure and plant (Scope 3, scope 1)	96 10	96 10	96 10
Transport of workers (Scope 3, scope 1)	776 159	776 159	776 159
Water haulage (Scope 3, scope 1)	265 21	265 21	265 21
Vegetation clearances (Scope 1). Based on clearance of 1,027 ha	205,561	205,561	205,561
Embedded energy related emissions for steel pipes (Scope 3)	76,302	58,779	43,389
Pipeline commissioning (Scope 1)	23	23	23
Pipeline decommissioning (Scope 1)	1,191	1,191	1,191
Total (across project life time) in kg	**311,369**	**293,848**	**276,458**
Activities	Operational GHG emission kg CO_2e per year		
Pipeline fugitive emissions (Scope 1)	8,720	8,720	8,720
Pipeline blowdown (Scope 1)	4,780	4,780	4,780
	6”NPS150	**5”NPS125**	**4”NPS100**
Total annualized emissions in tonnes CO_2-e /km pipeline (lifetime = 20 years)	**29.07**	**28.19**	**27.42**

Table 6: Emission factors in kg or tonnes CO2 -e for the activities during the pipeline's construction. Sourced and derived from WorleyParsons & Pacific Aluminum, 2013.
The scopes are specifically for the study itself, and it is equivalent to the scopes in this study.

Emissions factors for all of the activities during the pipeline construction were based on a 6” pipe diameter derived from the assessment study, except for the embodied energy. Embodied energy refers to the energy used to extract, produce, and transport materials for pipe manufacturing in addition to the manufacturing process itself (Wu et al., 2010). Finally, for the annual emissions related to energy consumption (electricity) associated with the pipeline operation, a reverse calculation is used depending on total pipeline cost, electricity cost percentage, CO_2 emission intensity, and electricity cost per country.

3.5.3 GHG emissions from the storage site (well pad & injection)

There is a massive scarcity regarding the actual GHG emissions from CO_2 storage sites, whether on-shore or off-shore. Moreover, most injection sites are offshore due to the availability of large geological reservoirs, and due to the more effortless safety measures, onshore sequestration of CO_2 is cheaper (ZEP, 2011). The injection site infrastructure itself is usually not independent; the onshore CCS systems usually operate in a cluster with other infrastructures such as the facilities at Rotterdam's port where the Athos CCS facility is operating. Therefore, for a simple inventory of the GHG from an onshore injection site, some different well sites are considered, such as natural gas drilling wells and geothermal heat wells.

Based on an LCA of GHG from the Marcellus shale gas, the GHG estimated for developing the well site is considered. According to Jiang et al., 2011 (supplementary data), the GHG emissions from drilling a well, include the site preparation for production or injection by clearing the vegetation for the well pad area and the access road. The amount of GHG generated from a natural gas well is estimated between 1.9 to 5 kt of CO_2e for a rig depth of around 2300 m before gas production (Jiang et al., 2011).

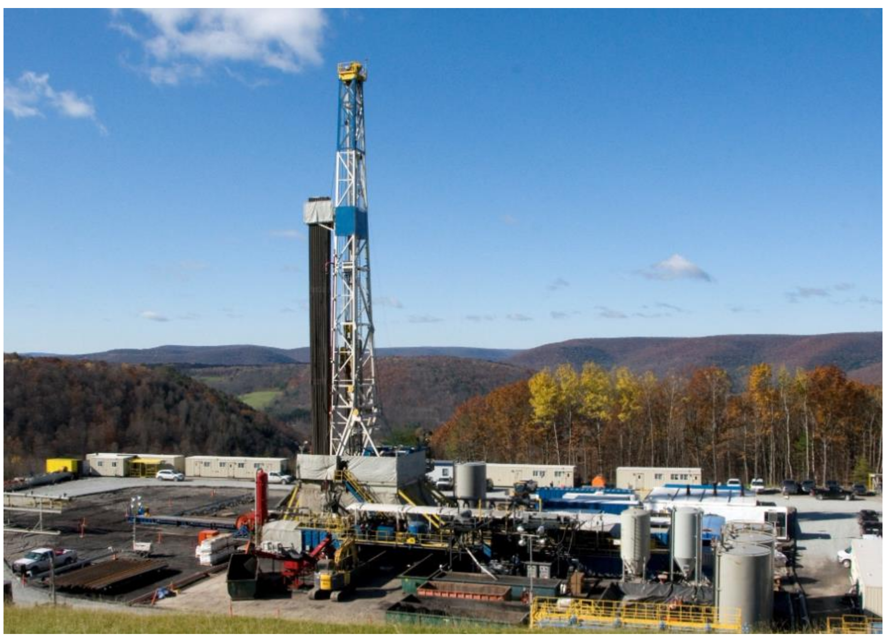

Figure 30: shows a type of Marcellus Shale drill site in Central Pennsylvania. Source: EMS-PSU. (n.d.).

McCay et al., 2019 calculated the GHG emissions of a well based on an LCA of a deep geothermal well. The study's standard scenario included drilling a 2000 and using around 3,800 liters/day of diesel consumption[7]. The high estimate scenario included drilling to a deeper level of 3,000 m where the calculated GHG ranged between 6,000 to 7,700 tonne of CO_2e, while the GHG for the standard case ranged between 3.8 to 5.5 kt tonne of CO_2-e (McCay et al., 2019). Hence, the one-off GHG emission estimated per injection site for this study is set at 6 kt tonne CO_2e based on the average of the two studies' higher-end values, namely 5 kt, 7.7 kt, and 5.5 kt of CO_2-e. Given the

[7] See Appendix B.19 to see the table of GHG emissions from the well in Banchory project in the UK from the article.

project lifetime of 20 years, the annual Scope 1 emission is set at 300 tons (6 kt/20). On the other hand, the annual emission is based on electricity consumption from the pumps calculated by equation (13).

4.Results

4.1 The selected cases (total ethanol and UBG plants)

Responding to the first sub-question of “What are the largest sources of intense and thick biogenic CO_2 emissions in Europe?”, It is found that both ethanol and biogas plants contribute to biogenic emissions as a standard part of the overall production process.

By surveying both ethanol and UBG plants, Initially, 30 ethanol plants and 18 UBG plants were selected. Some of the ethanol plants were disregarded because the generated biogenic emissions are utilized, and a few others were disregarded for being shut down or data uncertainty. For the UBG plants, six plants were disregarded after applying another criterion for inclusion. Finally, 34 plants were selected for potential CCS projects. Out of the 34 plants, 22 are ethanol plants scattered in the European Union, while the rest of the plants, 12 UBG plants, were all located in Germany. This contributes to answering the first subquestion, *“What ethanol and UBG plants to be included in the analysis?.”*

The total annual potential of biogenic emissions surveyed for storage ranges between 23 kt (case #21) to around 386 kt CO_2 (case #6) for ethanol plants (See Figure 31). The total annual biogenic emissions potential from the 22 plants estimated at around 2.72 Mt per year. On the other hand, for UBG plants, the range is between 11 kt to 39 kt $CO_{2,}$ with a total potential of 236 kt CO_2 approximately (see Figure 32). Thus, the total surveyed biogenic CO_2 from both plant types are roughly 3 Mt annually. Considering a CCSs lifetime of 20 years, a total of 60 Mt of CO_2 could be removed from the atmosphere by 2045 from 34 plants alone. Hence, the second subquestion, *“What is the total gross amount of biogenic CO_2 that could be potentially sequestered from these plants?"* is answered.

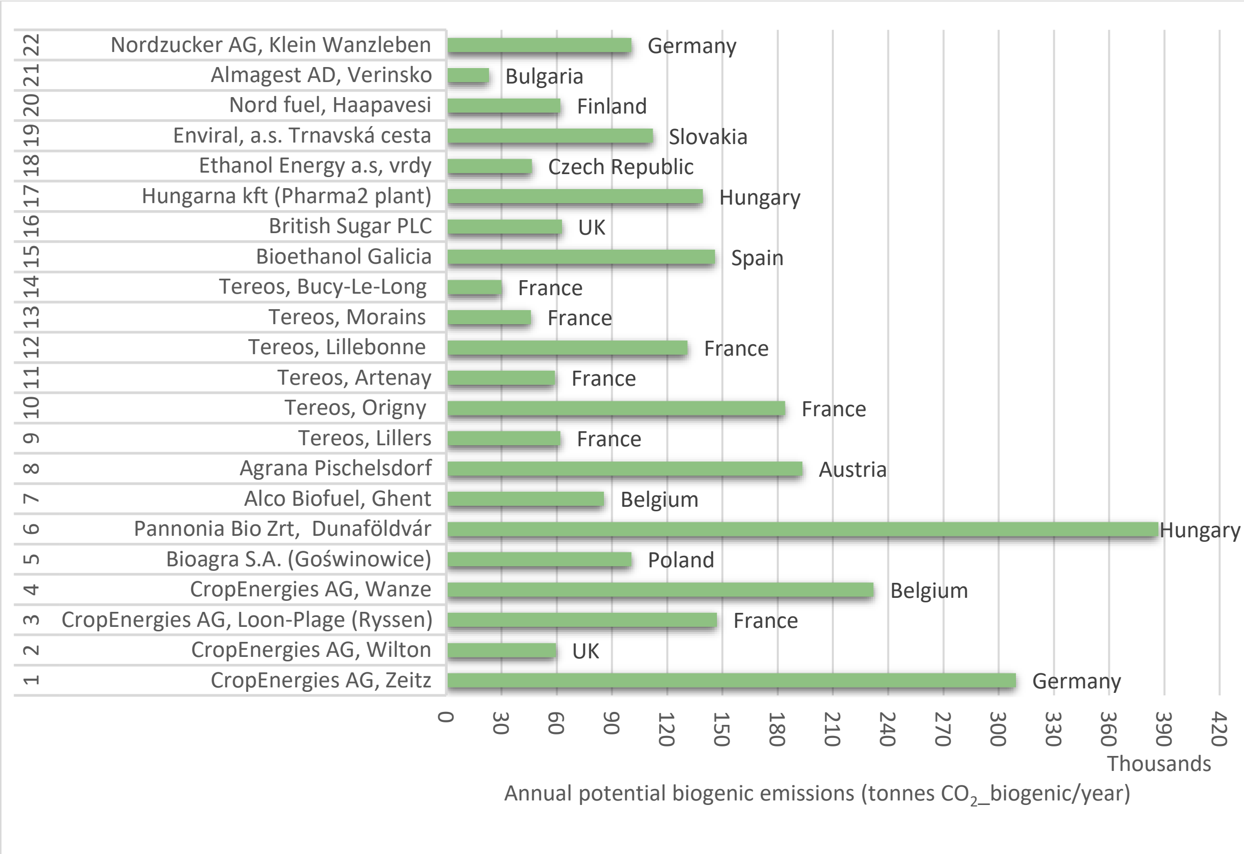

Figure 31: Ethanol plant cases and their annual biogenic emissions.

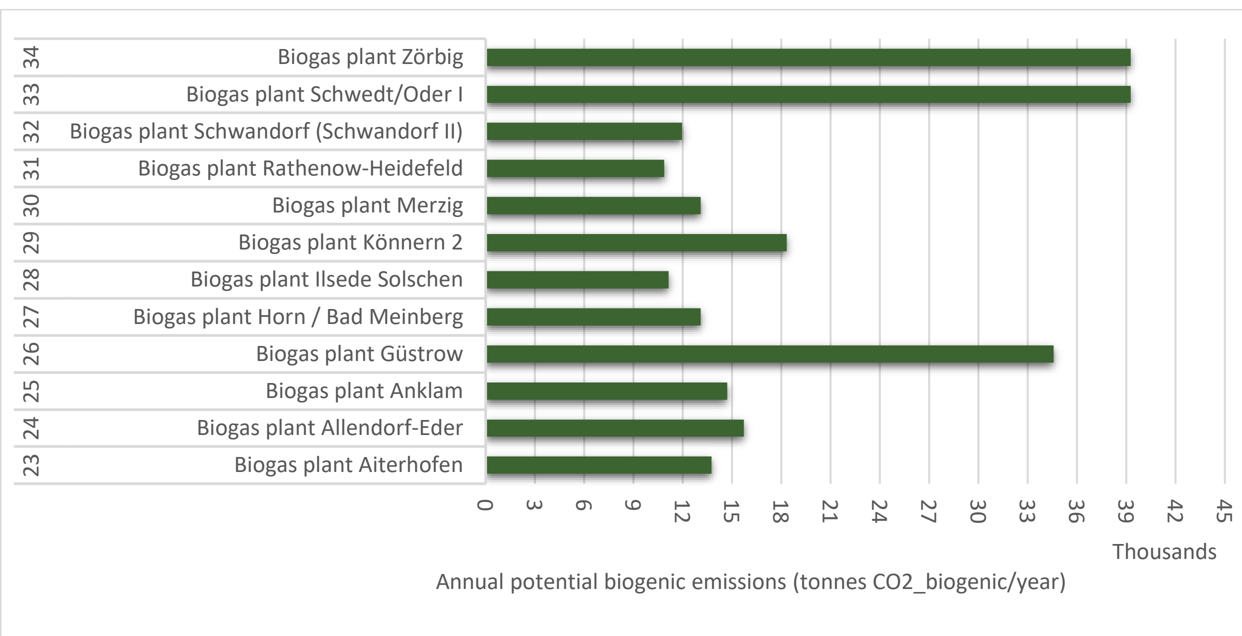

Figure 32: Upgrading biogas plants and their annual biogenic emissions. All the plants are in Germany

4.2 CCS chain cost assessment

4.2.1 Capture CAPEX and O&M

The following results answer the third subquestion (3a) *"What is the cost of capturing biogenic CO_2 from the ethanol and UBG plants?".*

For ethanol plants, the capture CAPEX ranges between 2.47 M€ for a 23 kt capacity plant to 21.76 M€ for a plant with roughly 387 kt. The average CAPEX is around 8.6 M€ for an average capacity of around 124 kt CO_2 per year. The annual O&M costs were based on a 4% to the total capture cost plus electricity costs for compression/dehydration if the commodity is transported by trucks because a 7.5 MPa condition is assumed to be sufficient and suitable for truck transportation (see section 3.2a). For the cases where pipelines are used as the 2nd transportation method, the annual O&M includes 4% of the CAPEX, electricity costs from compression, and the electricity cost from using one pump, which gives around 74 k€ per year. Note that for both compression and pumps, FHL is used. For the truck transportation scenario, the O&M costs range between 300 k€ to 4 M€ approximately, with an average cost of about 1.45 M€. See Appendix D.1 for an overview of the CAPEX and O&M costs of ethanol plants

Regarding UBG, the capital costs range between 1.63 M€ to 3.87 M€ for plants with a capacity range of 11 kt and 40 kt CO_2 per year, respectively. O&M costs for these plants are fixed at 3.5% of the total costs, with an average of 770 k€ approximately. The O&M includes the electricity consumption of 220 kWh to produce 1 tonne of liquid CO_2. See Appendix D.2 for an overview of CAPEX and O&M costs for biogas plants. See Figure 33 for a comparison between the capture CAPEX for both the plant types in addition to their O&M.

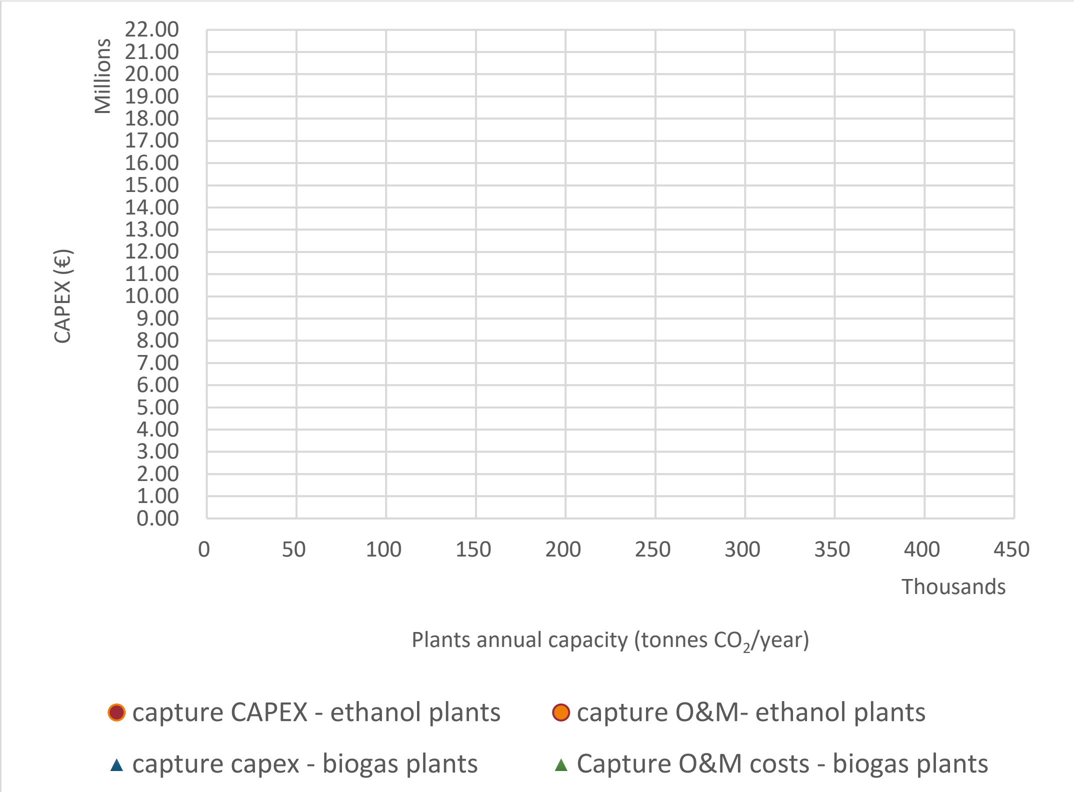

Figure 33: shows capture CAPEX and O&M costs for ethanol plants and biogas plants in €. O&M costs include the cost of electricity from compression only.

4.2.2a (Annual) cost of transportation by trucks

The results in this and the following section answer the third subquestion (3b) *"What are the suitable transportation methods, and how much they cost."*

All of the 34 cases were evaluated for road transportation by trucks, technically and economically. The cost for truck transportation is not considered CAPEX since it is not a one-off investment but rather an annual repetitive process from one year to another. For the 22 ethanol plants, the longest distance is calculated for plant #20 (Nord Fuel) in Finland over 768 km to the storage site, while the shortest distance calculated is found to be 37 km for plant #22.

Regularly, the cost per 1 truck (22 tons load) per the first km is 284 €, or it is 640 € per 100 km; the cost covers both back and forth trips, i.e., 200 km. The cheapest cost is based on transporting a small amount of CO_2 over a short distance (case #14). However, the average transportation cost is 5.5 M€ for an average distance of 200 km and an average capacity of around 124 kt CO_2 (see Figure 34).

For the biogas plants, the cheapest cost, similarly to ethanol, is related to the smallest annual capacity and a short distance to the storage site. However, the average transportation cost is roughly 700 k€ for an average capacity of around 20 kt and an average distance of 124 km (see Figure 35).

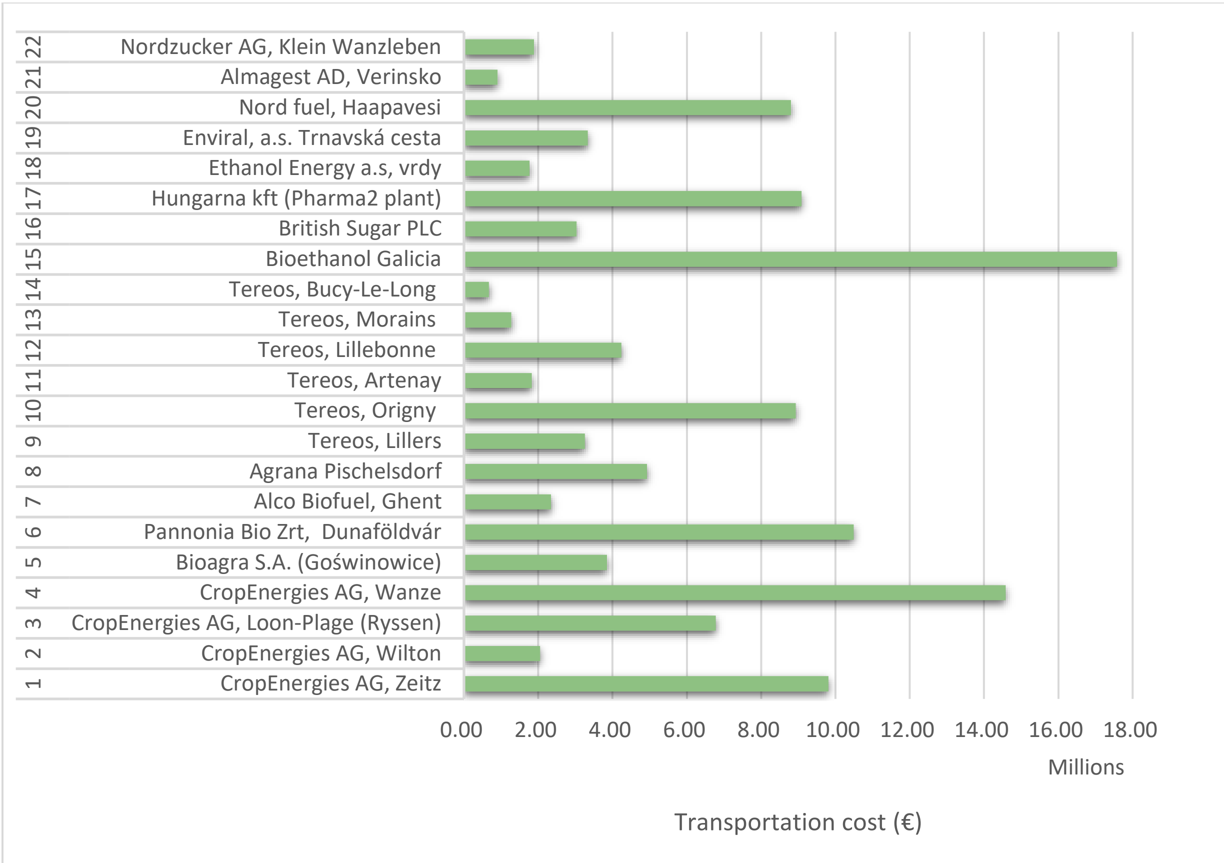

Figure 34: Annual cost of transportation by trucks for ethanol cases.

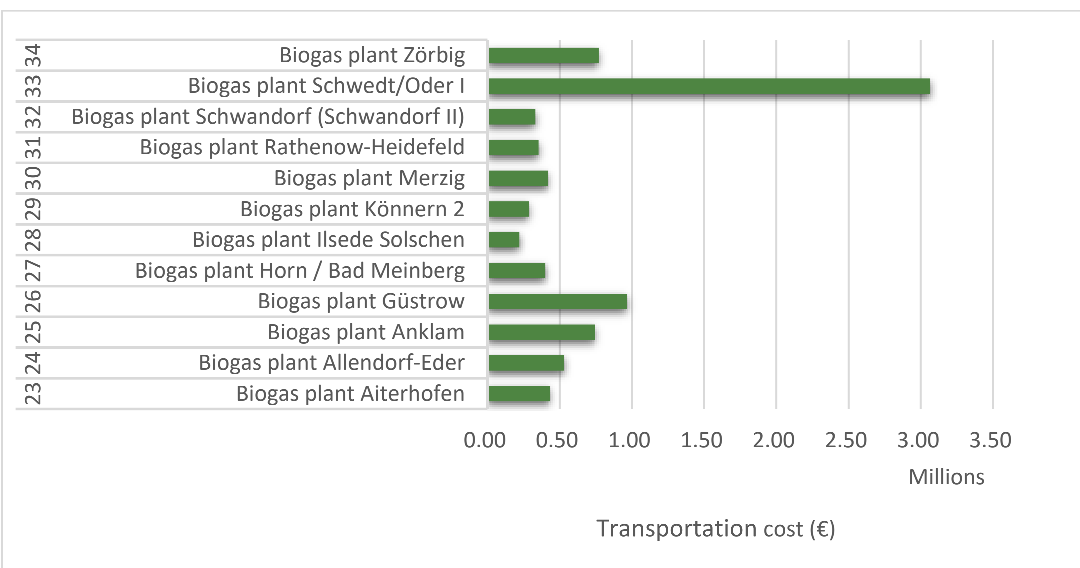

Figure 35: Annual cost of transportation by trucks for UBG cases.

Both distance and capacity play a substantial role in the cost estimation for transportation by trucks. To understand the influence of distance and capacity on the transportation cost, the correlation function by excel (Correlation coefficient) is used

It is found that with larger-scale cases, i.e., the ethanol cases, both factors have a positive correlation with the cost. This means that when distance or capacity increases, the cost increases as well; however, the effect of capacity is higher (0.66) than with distance (0.61). While the correlation in the cases of UBG plats, i.e., small-scale cases, is similarly positive but even with more considerable influence. Nevertheless, the impact of distance is greater (0.84) than for capacity (0.71). The impact of distance and capacity on the cost calculation could be observed in the Figures in Appendix D.3 and D.4 respectively.

For the large capacity plants, the number of trucks required is high. Given an operation time of 85%, i.e., 310 per year, the highest number of trucks needed per week is nearly 400 trucks (case #6). The average number of trucks required per year for all the ethanol and biogas cases together is nearly 3950 trucks or 13 trucks per day (see Figure 36). It is noteworthy that the number of trucks refers to the number of trips required to complete the transportation of liquid CO_2 to the storage site. A limited number of trucks may repeat the transportation over a period of time without the need to bring in more trucks, depending mainly on the distance between the start and endpoint.

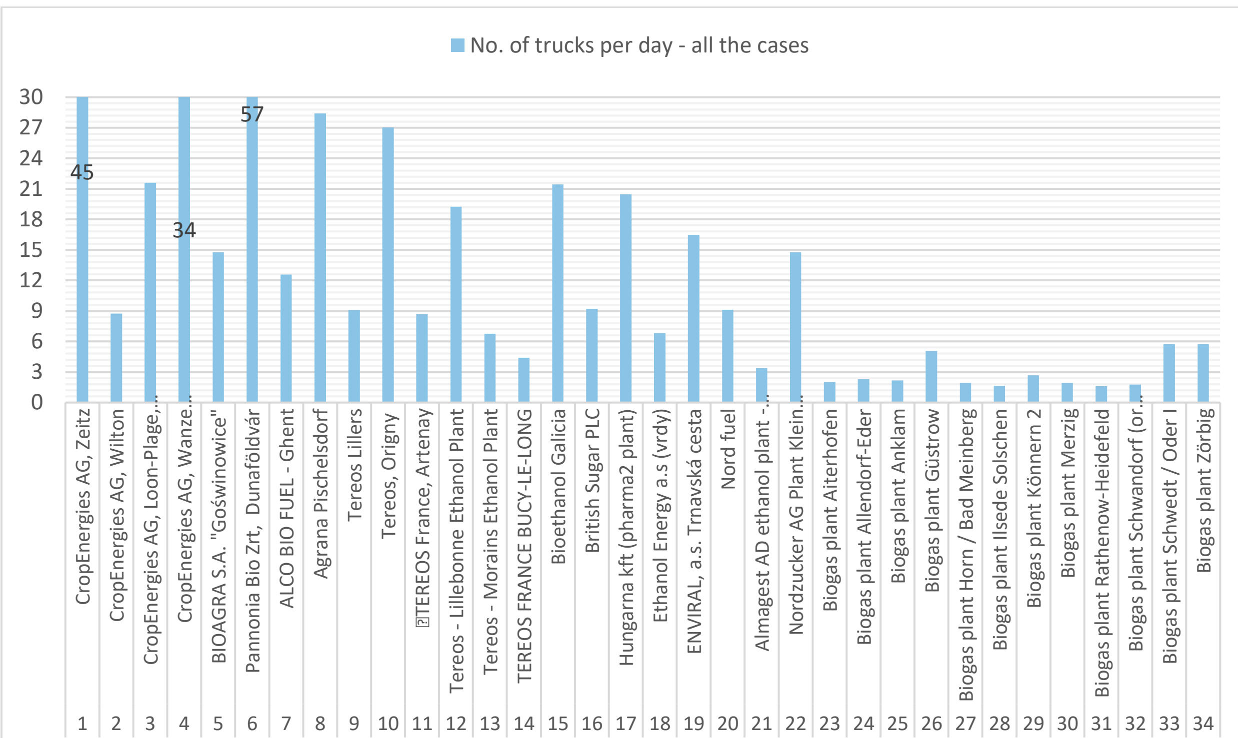

Figure 36: Number of trucks required per day per case to transport the annual liquid CO2 to the storage site. The labels for biogas cases (light blue line) are not shown; the numbering starts from the left (#23) to the right (#34).

4.2.2b Pipelines design, properties, and CAPEX

Due to the small amount of CO_2 produced at most plants, only large ones were considered for pipeline transportation, where in total only 10 cases were eligible for the pipeline method, while the rest were disregarded. All the pipeline cases together can transport around 2 Mt of CO_2 per year; and can deliver around 40 Mt CO_2 over the period f 20 years.

In almost all of the literatuers, the smallest pipeline diameter reported was at least 4”; similarly, the same criterion was used in this thesis. Thus, all of the ten cases have pipeline diameter sizes vary among 4”, 5” and 6”s and all are assigned to ethanol plants. Moreover, all the pipeline cases require a wall thickness of at least sch40 standards for volumetric flow rates ranges between 15.2 to 52.5 m^3/h. See Appendix D.5 for the complete pipeline list and D.6 to review the Nominal pipe sizes.

The longest pipeline route from the list is Bioethanol Galicia (case #15, 4”) in Spain for 636 km and a capacity of 146 kt CO_2 per year. Overall, the pipeline lengths averaged at 217 km and just 170 km, excluding the outlier case of #15. The lowest plant capacity eligible for pipeline transportation is at least 112 kt considering a minimum diameter of 4”(ID = 102.3 mm). One of the crucial aspects of pipelines is the pressure drop across the pipeline trajectory, where a booster pump is needed to re-pressurize the transporting fluid. On average, all of the cases experience a pressure drop by 21.3 Pa/m, where the highest pressure drop is 28 Pa/m for case #3, and the lowest one is for case #10 with 14.22 Pa/m. Most cases have an average outlet pressure of around 12 MPa; only in two cases, booster pumps were required, namely case #15 (2 pumps) and case #17 (1 pump). Review the pressure drop graph in Appendix D.7.

Two methods were used to calculate the pipeline's CAPEX; the first model is based on Piessens et al., 2008 (Figure 38), and the 2nd method is based on Knoope, 2015 (Figure 37). However, the material cost for the first method is calculated using the method by Knoop, 2015. The overall cost covers the cost of materials (pipes only), labor costs, ROW costs, Miscellaneous costs, one surge tank, pipeline control system, and pumps. The last three components were similar for all cases, except for cases #15 and #17, where additional pumps along the pipeline were required. Both the methodology`s components costs are illustrated in Figures 34 and 35. Moreover, the O&M costs are fixed at 3% of the total pipeline CAPEX, i.e., 3% of the total component's costs.

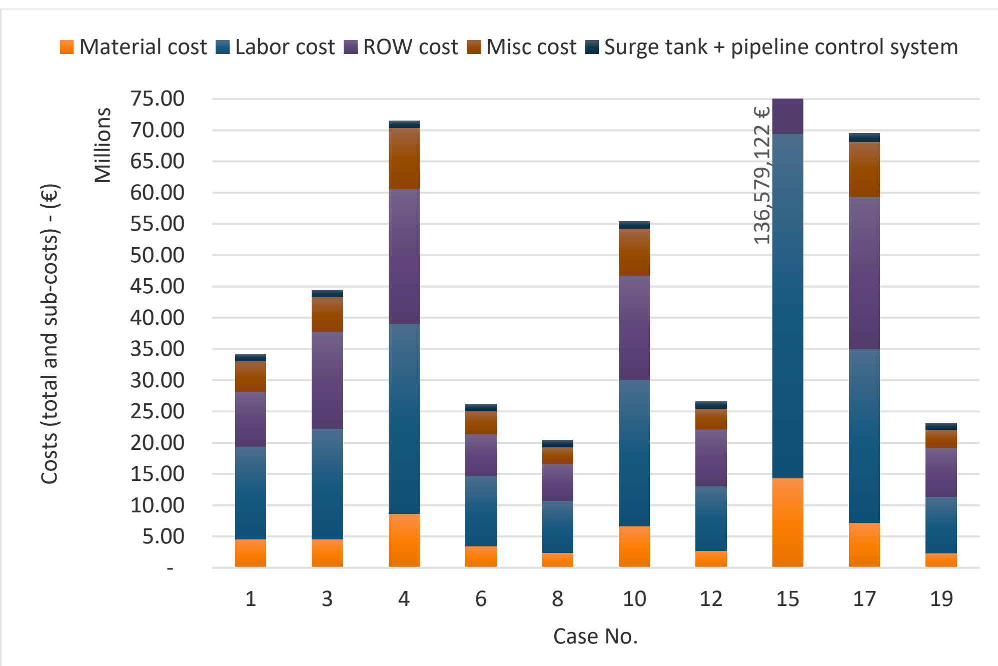

Figure 37: Pipeline CAPEX, using Knoope`s model, divided into the components: materials, labor, ROW, Misc, surge tank & control systems. For the case numbering, see Figure 36, for instance.

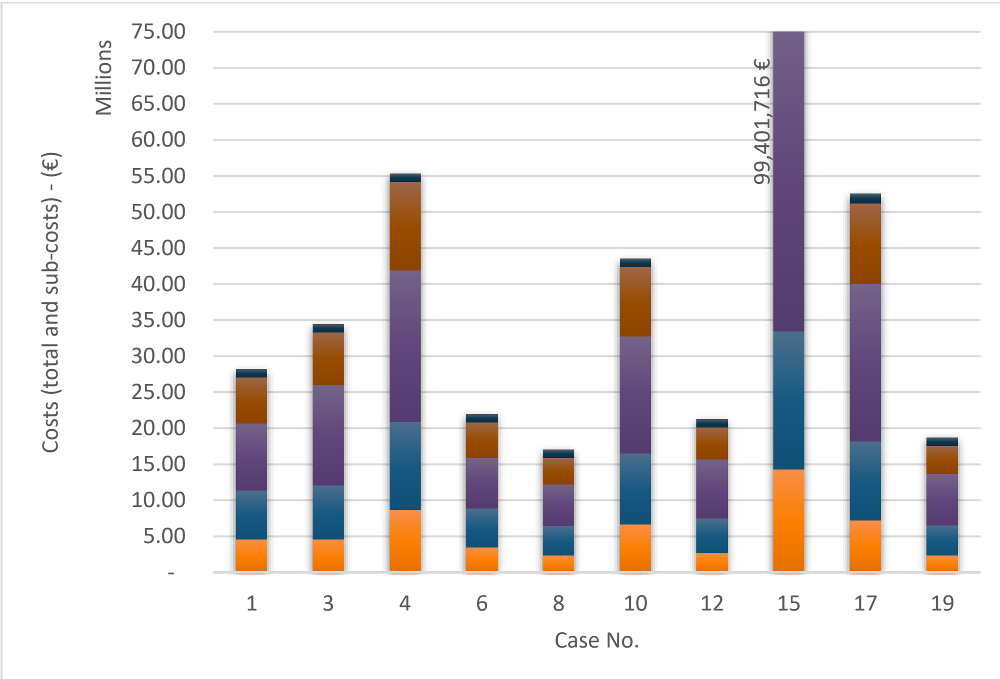

Figure 38: Pipeline CAPEX, using Piessens`s model, divided into materials, labor, ROW, Misc., surge tank & control systems. For the case numbering, see Figure 36, for instance.

The lowest pipeline CAPEX is 17 M€ if the method by Piessens is used and 20.4 M€ if the method by Knoop is used. This is calculated for the ethanol plant of Agrana Pischelsdorf (case #8) in Austria for a route length of 78 km and 5” pipe diameter (ID = 128.22 mm). On average, the pipeline CAPEX is estimated at 32.5 M€ using the Piesens model and excluding the outlier case #15, and the average CAPEX is 41.3 M€ by the 2^{nd} model.

Given the properties chosen for the Carbon Dioxide and the overall pipeline design, in addition to the minimum pipeline diameter (4”), the mass flow level where pipeline becomes a proper method of transportation against trucks is at least 3.45 kg/s CO_2. The breakeven limit can be expressed as an annual amount of around 109 kt CO_2 for an FHL operation time or around 93 kt for an 85% operation time. This shows the technical feasibility of pipeline transportation versus road transportation, where only some of the ethanol plants are eligible for pipeline transportation. In contrast, none of the biogas plants is eligible for pipeline transportation unless an inter-modal network is used where the available CO2 volumes are transported by trucks to a collecting hub or temporary storage point and then transported by a single pipeline towards the storage point. However, the latter is not taken into account in this study. Review Figure 39 for comparing annualized costs of pipeline against truck transportation plotted on capacity axis. See the truck transportation plotted against distances in Appendix D.8.

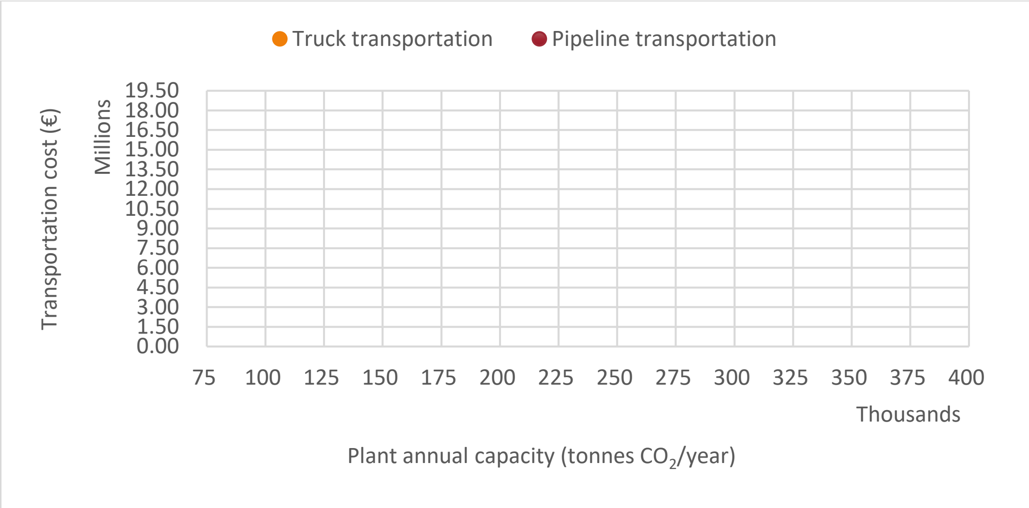

Figure 39: shows transportation cost plotted on the capacity axis for both methods, trucks, and pipelines. See also D.8 for the same cost demonstration on the distance axis.

4.2.3 Storage points CAPEX and O&M

The following results answer the third subquestion (3c) *"What is the cost of CO_2 injection and storage?"*.

The storage points were based on the assumption that gas underground storage points are suitable technically to store biogenic CO_2 for a lifetime of 20 years. Each ethanol case is assigned with one storage point, while for biogas cases, all are assigned virtually to one storage point. The storage points are scattered in the European union close to the point sources. See Appendix D.9 for the complete list of plants with their assigned storage points, and the link to the network on Mapifator is also provided.

Technically, four types of onshore geological reservoirs were used from GIE storage points; Salt caverns, aquifers, Depleted gas fields, Rock caverns, where 11 are DGF, 10 are aquifers, 11 are salt caverns, and just one is rock cavern or crystalline structure. However, given the data availability, just three types of onshore geological reservoirs could be constructed for cost calculation, namely DOGF, DOGF re-use, and aquifers. The CAPEX of the three types is presented in Table 7.

The O&M costs are fixed at 5% of the total capital cost plus one pump's electricity cost for FHL operation time. Overall, the cheapest storage option is to acquire a re-usable injection site where site development costs and other equipment costs are the minima. At the same time, the most expensive is on-shore aquifers.

Parameters	DOGF (hydrocarbons)	Aquifer	DOGF with re-use
Total CAPEX (M€)	9.00	27.7	3.95
O&M cost	5%	5%	5%
Electricity cost of 1 pump	Variable per country		

Table 7: Storage types and the individual CAPEX.

4.2.4 Distribution of the total CCS costs to capture, transport and storage

The sub-costs of CCS steps compose together the final cost to store one tonne of biogenic CO_2. These sub-costs can vary due to the available capacity or the planned distance. On average, the storage cost has the highest share of the total CCS cost for ethanol cases (44%). This is due to the fixed cost of the storage step, which decreases if the plant capacity is high or/and if the distance is longer. Interestingly, the transportation cost represents the cheapest cost with a share of around 21% only. The range can be as low as 5% or as high as 50% - see Figure 40.

In contrast, one storage cost per one injection site is shared among the twelve cases for the UBG plants. Therefore the share of storage cost for the biogas cases is much lower than the ethanol ones (20%). The transportation costs are even cheaper than ethanol cases, with an average of 15%. It is noteworthy that these costs exclude the O&M and are bound to the main CAPEX costs for capture and storage and the annual costs of truck transportation. In the Figure below, the total cost is broken down into sub-costs for scenario 1 (see section 4.2.5 for elaboration on the established scenarios).

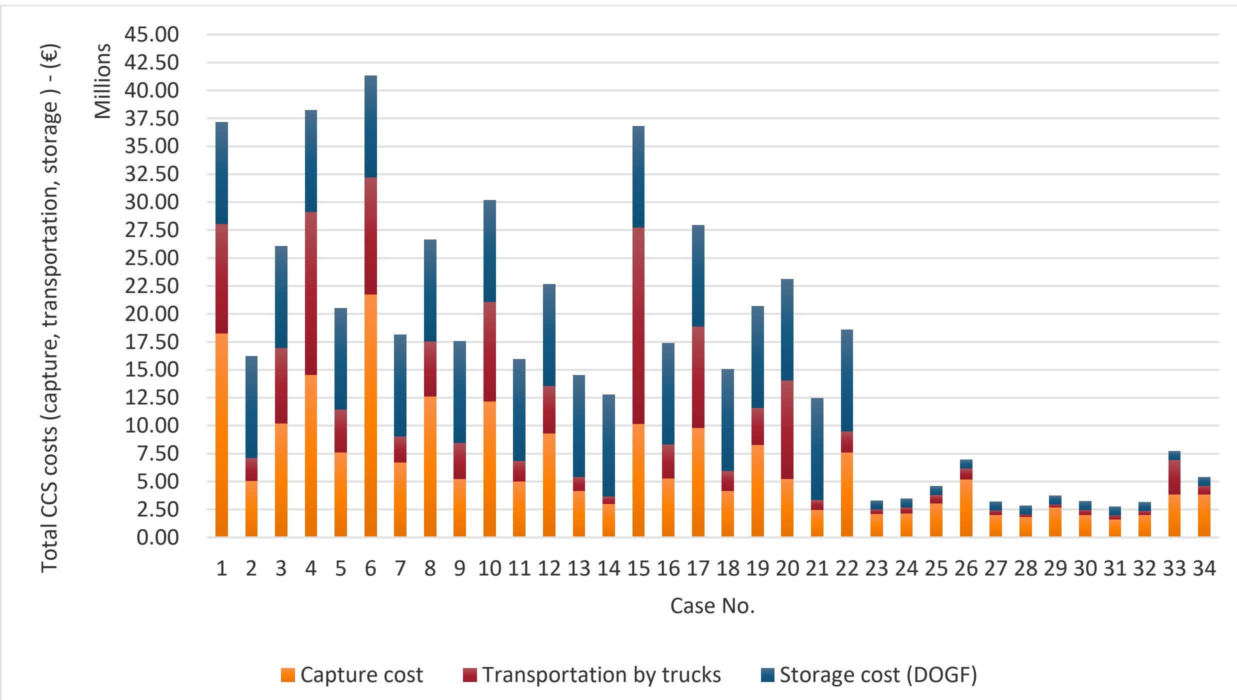

Figure 40: The total final CCS costs and their sub-costs are broken down to capture costs, transportation costs, and storage costs. O&M costs are not included.

In the pipeline cases, the transportation cost occupies the highest share of the total costs, with an average of 60% in scenario 1. On the other hand, storage cost represents the lowest share of the total cost for nine of the cases (see Figure 41).

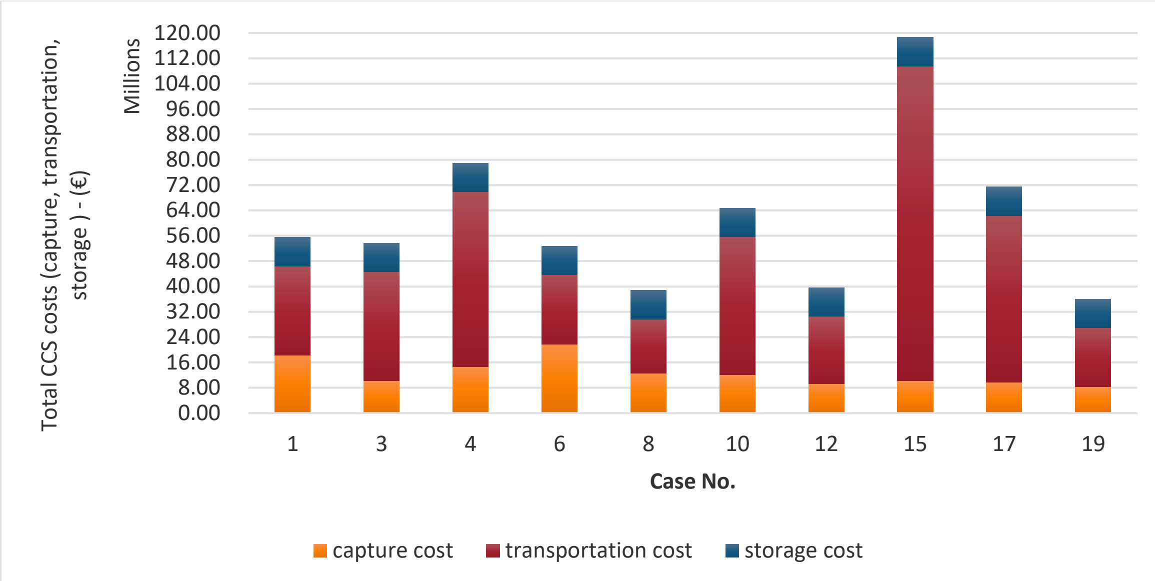

Figure 41: The total final CCS costs and their sub-costs are broken down to capture costs, transportation costs, and storage costs. O&M costs are not included.

4.2.5 Abated emissions

Partial LCA was applied to inventory the emissions from implementing CCS units for all three steps. The capture step involved emissions from the electricity consumption for compression and pumping. While for the pipeline and storage site, the emissions analysis involved the construction phase as well. Generally, the emissions from the storage sites are the lowest compared to emissions from capture and transportation methods (see table 8). For the capture step, the emissions from the compression depend highly on the country`s electricity intensity. For instance, 18.6 Million kWh in France resulted in less than 1 kt a year, while 14.7 kWh in Spain resulted in 3 kt. These emissions will be considered negligible if renewable sources would be used. Overall, capture and transportation occupy the largest share of the total annual GHG emissions (see Figure 42).

Steps	Calculation type	UBG plants	Ethanol plants		
		Trucks (12 cases)	Trucks (22 cases)	Pipelines (10 cases)	Trucks (10 cases)
1) Capture	Average	1.5 kt	2.4 kt	3.5 kt	3.4 kt
	Total	17.5 kt	54 kt	35 kt	34 kt
2) Transportation by trucks or trucks	Average	0.4 kt	3.7 kt	6 kt	6 kt
	Total	5 kt	80 kt	61	61 kt
3) Storage	Average	0.3	0.4 kt	0.4 kt	0.4 kt
	Total	4 kt	8.4 kt	4 kt	4 kt
TOTAL emissions		**26.5**	**144 kt**	**100 kt**	**99 kt**

Table 8: Total annual GHG emissions for the cases collectively and per CCS chain in (kt/year). Possible comparisons include ethanol cases against biogas cases and pipeline transportation cases against 10 truck transportation cases.

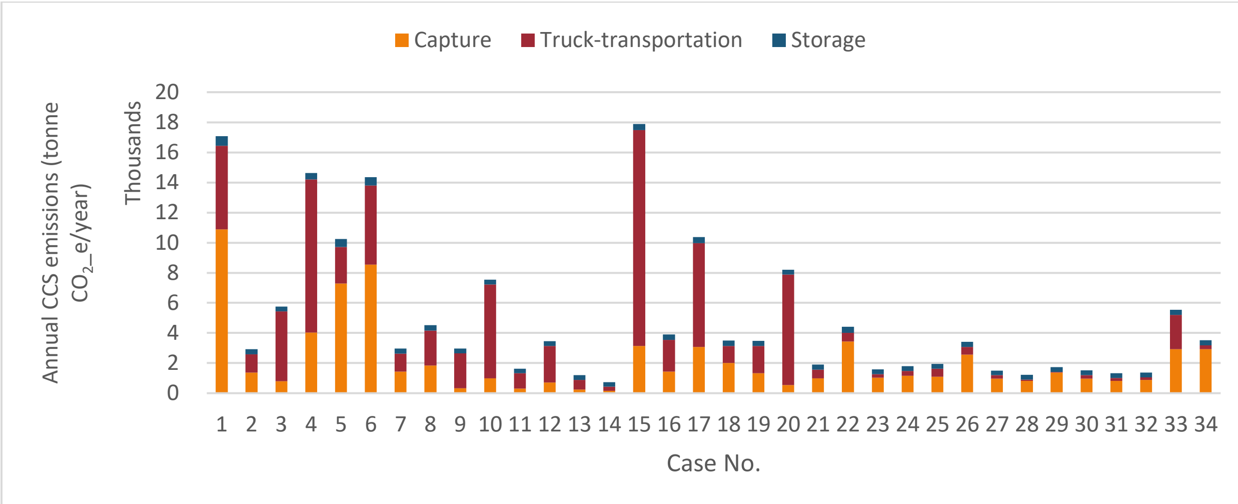

Figure 42: Shows the total GHG emissions (tonne CO2_e/year) for each of the cases, in addition to the sub-emissions per CCS step. The capture step includes emissions from compression and dehydration only. Storage emissions include annualized construction emissions in addition to the emissions from the electricity consumption from one pump.

The GHG emissions are interestingly identical for both pipelines and trucks - see Figure 43. The extreme pipeline emissions during construction, if it is annualized and with the operation, will emulate the annual emissions from utilizing the trucks. Finally, the total net emissions abated for ethanol are around 2.57 Mt and 0.2 Mt from the biogas plants if trucks are used (a total of 2.8 Mt) - see the figures in Appendices D.10 and D.11. In case if pipelines would be used, around 1.9 Mt of biogenic CO_2 could be sequestered annually. The latter findings answer the fourth subquestion, *"how much net biogenic CO_2 could be sequestered from the selected plants?"*.

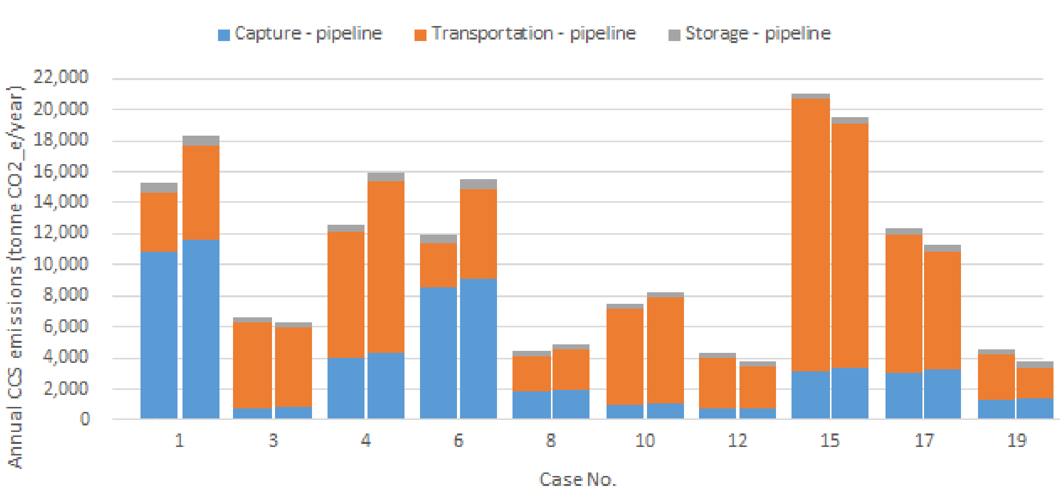

Figure 43: Shows the total annualized GHG emissions (tonne CO_2_e/year) for 10 of the cases, in addition to the sub-emissions per CCS step. The left sides resemble the total GHG emissions if pipelines are used,

and the right sides resemble the total GHG emissions if trucks are used. The pipeline cases also include the emissions from one pump.

4.2.6 Marginal Abatement costs (MAC)

The potential amount of biogenic CO_2 that can be abated over 20 years is evaluated economically using Marginal Abatement Costs (MACC). As given in section 2.1.1, the MACC is calculated using only the costs, i.e., the investment and annual costs. Additionally, the CRF is calculated based on the social discount rate (4%).

The results are presented under three scenarios given that two transportation methods are evaluated against three types of storage sites. Thereby, each case study is evaluated with at least three different MACCs for both transportation methods. See the complete lists in Appendix D.12, D.13, and D.14. Also, Each of the scenarios is briefly explained in the following sub-sections.

Finally, the results in the following scenarios answer the fifth (last) research`s subquestion *"What is the cheapest cost scenario to abate the biogenic emission within the selected plants?".*

Scenario 1

Within this scenario, two MACC results are presented; one is for all 34 cases where trucks are used as the transportation method and DOGF as the storage point (Capture-Trucks-DOGF). Second, MACC results for the 10 pipeline cases where the CCS chain includes Capture-Pipelines-DOGF storage point. Moreover, from two results of pipeline CAPEX, the method by Piessens is used for being cheaper than the model by Knoope (Capture-pipeline "Piessens"-DOGF).

The abatement cost range between 47 to 204 €/tonne CO_2 for road transportation. The average abatement cost is 85 €/tonne $CO_{2,}$ where more than half the cases are cheaper than the average level (see Figure 44). Thus, the largest capacity and almost shortest route length (case #6) represent the cheapest costs. On the contrary, the most expensive, 204 €/tonne CO_2, is found for case #20, with the farthest storage point and a capacity of just 62 kt annually.

The average abatement cost is 51 €/tonne for the pipeline cases, with the cheapest being just 25 €/tonne for case #6 again. Excluding the outlier case of #15, the averages decrease to just 44 €/tonne for the rest (Figure 45). Thereby, it is possible to abate around 2.6 Mt annually with 85 €/tonne by trucks or 1.88 Mt per year with 51 €/tonne with pipelines.

The abatement cost for UBG plants ranges between 74 to 146 €/tonne $CO_{2\_bio,}$ with an average cost of 101 €/tonne CO_{2_bio}. Thus, about 210 kt per year can be abated from biogas plants with an average cost of 101 €/tonne (see Figure 46).

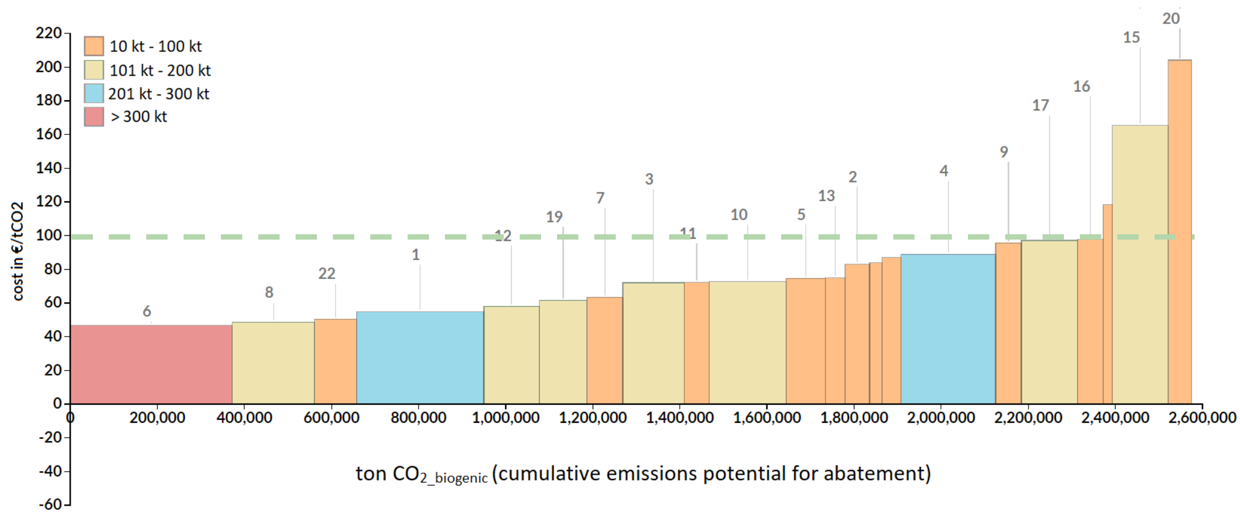

Figure 44: Shows the abatement potential in scenario 1 for ethanol plants. The numbers above the histogram represent case Numbers. The dashed light green represents the feasibility limit in this study.

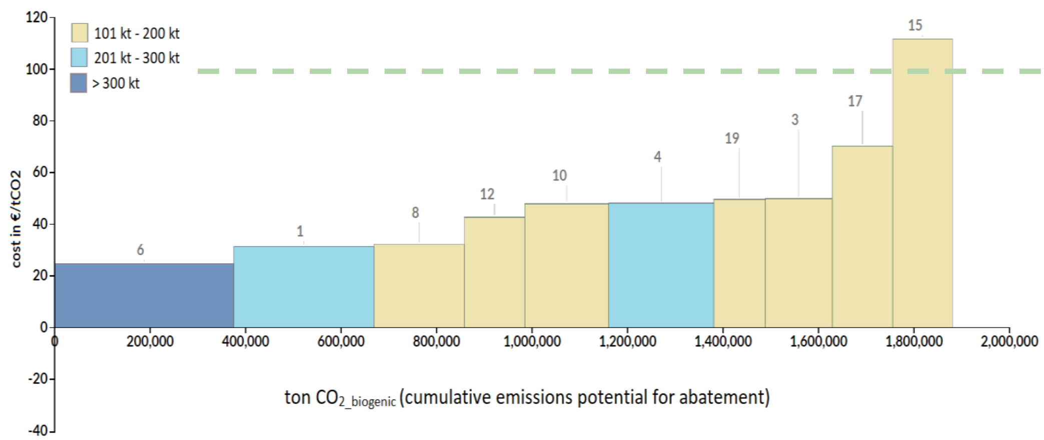

Figure 45: Shows the abatement potential in scenario 1 for pipeline cases. The numbers above the histogram represent case Numbers. The dashed light green represents the feasibility limit in this study.

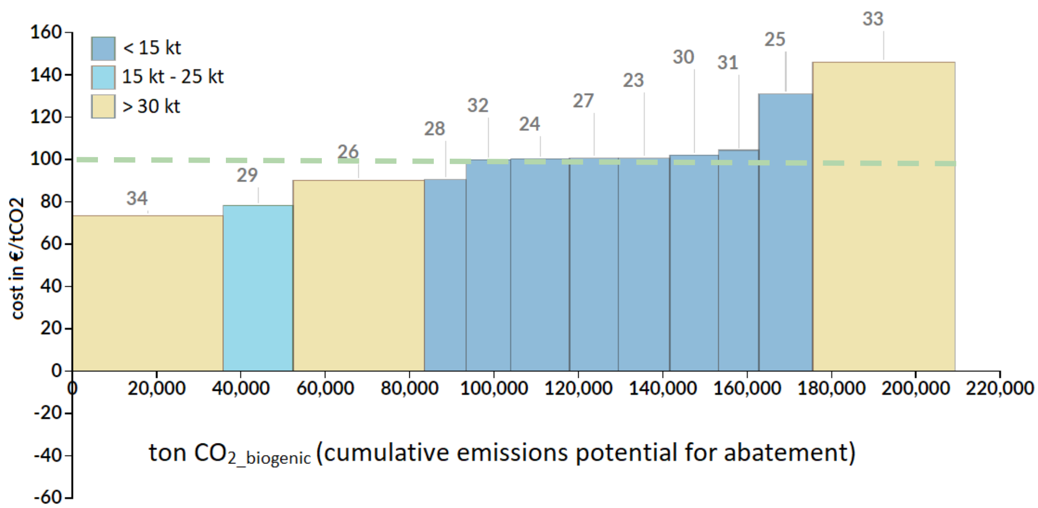

Figure 46: Shows the abatement potential in scenario 1 for the biogas plant. The numbers above the histogram represent case No.

Scenario 2:

Within this scenario, two MACC results are presented; one is for all 34 cases where trucks are used as the transportation method and DOGF re-use as the storage point (Capture-Trucks-DOGF re-use). Second, MACC results for the 10 pipeline cases where the CCS chain includes Capture-Pipelines-DOGF storage point. Moreover, from two results of pipeline CAPEX, the method by Knoope is used; to examine the feasibility of the cost when the cheapest storage point is used with the more expensive pipeline costs (Capture-pipeline "Knoope"-DOGF).

If DOGF sites with re-use wells and equipment are used, the abatement cost ranges from 44 to 192 €/tonne CO_{2_bio}, with an average cost of just 76 €/tonne if the transportation is carried out by trucks. Around 68% of the cases are cheaper than the average, together can abate more than 1.9 Mt annually with an average cost of 59 €/tonne (see Appendix D.15). this scenario represents the cheapest among the three scenarios, given that the wells are not developed from scratch but rather the available platform, equipment, and units are used with modification and other installations.

In the pipeline cases, the abatement cost range between 24 to 137 €/tonne CO_{2_bio}, with an average cost of 55 €/tonne. Without the outlier case, i.e., the highest cost (137 €/tonne), the nine cases average at 46 €/tonne. These pipelines can deliver 1.88 Mt annually to storage sites with a cost at the average rate. Review the MACC chart in Appendix D.16.

The average cost is 98 €/tonne CO2_bio for the biogas plants, with the cheapest cost being case #34 with an annual abatement capacity of around 35 kt. The most expensive is case #33, with a similar capacity to the cheapest case; however, the distance to the destination point is the longest. Review the MACC chart in Appendix D.17.

Scenario 3:

Within this scenario, two MACC results are presented; one is for all 34 cases where trucks are used as the transportation method and Aquifers as the storage point (Capture-Trucks-Aquifer). Second, MACC results for the 10 pipeline cases where the CCS chain includes Capture-Pipelines-DOGF *storage point. Moreover, from two results of pipeline CAPEX, the method by Piessens is used; to examine the feasibility of the cost when the costliest storage point is used with the cheaper pipeline model (Capture-pipeline "Piessens"-Aquifer).*

Provided that the aquifer type of reservoirs is the most expensive, this scenario's abatement costs are the costliest. The average abatement cost from ethanol plants is 117 €/tonne CO_{2_bio}, with the most expensive case being #20 (247 €/tonne). In contrast, the cheapest mitigation cost is 53 €/tonne for case #6, as it is in the first and second scenarios (Appendix D.18). Regarding the pipelines, the most expensive would be case #15 with 130 €/tonne against 183 €/tonne if trucks were used instead. The 10 pipeline cases have an average of 65 €/tonne compared to 91 €/tonne if trucks were used for these cases—review Appendix D.19 for mitigation costs in scenario 3 for the pipeline method.

With biogas cases, the costs are also more expensive than in the first two scenarios. The average abatement cost is 115 €/tonne CO_{2_bio} compared to 102 €/tonne and 98 €/tonne for first and second scenarios. The cheapest investment would be case #34, where the mitigation cost is 79 €/tonne CO_{2_bio}—review Appendix D.20 for biogas plants in scenario 3.

5.Discussion

5.1 Critical review of the results

5.1.1 MACC final results and interpretation

This research aimed to assess the techno-economic feasibility of integrating CCS with biogenic sources of Carbon Dioxide. The objective was specifically to calculate the Marginal Abatement Cost Curve for some plants where biogenic CO_2 is thick and rich and requires minimum effort to capture. Results show promising Figures for all pipeline cases except for the outlier case (#15), where a very long distance is designed to the storage site. Since MACC depends highly on the amount of CO_2 abated and that only larger capacities were assigned to be transported by pipelines, this led to cheaper costs for the pipeline cases in all three scenarios than if road transportation was used. However, truck transportation still shows sanguine Figures. Even for annual capacities greater than 100 kt (0.1 Mt)[8], truck transportation is still competitive to some extent with pipelines. According to Driessen (Personal communication, January 14, 2021), traditionally, only small capacities of liquid CO_2 are transported by trucks for utilization, starting from as low capacities as 10 kt or 12 kt. Nevertheless, large quantities could be economically feasible as well, even in the expensive scenario.

According to a study by Consoli 2019 (Global CCS Institute), the BECCS (ethanol with CCS) costs range roughly between 17 to 146 €/tonne avoided[9]. This is highly similar to the costs in this study's cheapest scenario, where abatement cost ranges between 24 to 137 €/tonne avoided (if pipelines are used for transportation). According to Fuss et al.`s literature review, generally, the costs of BECCS range between 25 to 334 €/tonne avoided[10] (Fuss et al., 2018). The mitigation costs from ethanol and UBG plants in this study fall within this range approximately where the lowest mitigation cost is 24 €/tonne CO_{2_bio}, and the most expensive is 247 €/tonne (see the full MACC lists in Appendix D.12, D.13, and D.14).

Langholtz et al., 2020 found the cost of BECCS utilizing ethanol with CCS to start from 25 €/tonne [11] in the US if the storage site is within 80 km approximately. The reference also reported a cost range of 35 to 77 €/tonne CO_2 avoided[12] approximately under the 2040 scenario. Furthermore, according to an IPCC, 2018, a broad assessment of BECCS range between 42 to 209 €/tonne sequestered approximately (Langholtz et al., 2020). Emenike et al., 2020 reported that the abatement cost for BECCS must be in the range of 50 to 102 €/tonne[13] to become economically feasible. Similarly, Hepburn et al., 2019 presented the break-even costs for BECCS in the range of 50 to 133 €/tonne avoided.

Following the cost ranges mentioned above, the average range of the abatement costs is between around 50 to 200 €/tonne (an average of 125 €/tonne_abated). Therefore, the feasibility of this research's abatement costs is set at a strict limit of 100 €/tonne_abated for all

[8] The unit is shown in kt because it's the usual units in this study, but the "Mt" is shown to emphasize the large quantity because the traditional units in other fossil-based CCS studies are rather in Mt, not kt.
[9] In the article, the cost range is in US$ 20-175.
[10] US$ 30–400/tCO2.
[11] US$ 30/ton. Using Xe.com the cost is converted to 25 €.
[12] US$ 42 to 92/ton CO_2 avoided.
[13] In the article, the cost is between 46£ to 88£ and are converted to Euros using Xe.com

the cases; considering a safe zone of 25 € to avoid overestimating the feasibility limit. Thereby, the number of feasible cases in the three scenarios is shown in table 9, and the range of Min-Average-Max is also given. See the complete MACC values highlighted in green in Appendix D.12, D.13, and D.14.

Overall, pipeline cases show propitious Figures in all three scenarios, with almost all of the cases, fall within the feasibility range. Therefore, they are highly recommendable than trucks for capacities greater than 100 kt (93 kt to 109 kt) and distances up to 320 km. However, larger capacity cases may compensate for the cost even for longer distances because they are inter dependable considering the project`s lifetime. Overall, around 1.76 Mt of net emissions could be abated annually (gross of 1.8 Mt) with 49 €/tonne based on the average of three scenarios.

If trucks were used as the transportation method, the ethanol cases are similarly and impressively feasible in scenario 1 and scenario 2 where only three cases are excluded. Considering scenario 2, around 2.4 Mt of net emissions could be abated (gross of 2.5 Mt).
UBG plants show auspicious Figures in Scenario 2 more than in Scenario 1. With an average price of 90 €/tonne, around 163 kt of net emissions could be abated annually (gross of 182 kt).

In the third scenario, less than half of the cases (ethanol and biogas) could be described as feasible. However, together can still abate around 1.98 Mt of net emissions annually (gross of 2 Mt). Considering all the scenarios together for both truck and pipeline transportation, 73% of the cases are feasible (see the number of all feasible cases in Table 9)

Generally, compared to other CDR`s, the BECCS is somewhat competitive in terms of costs and the potentials to achieve significant negative emissions (see table 9). Based on an intense literature review by IPCC, 2018, BECCS can achieve a reasonable amount of negative emissions up to 2050 globally, even though the high-end potentials are surpassed by ocean alkalinization fertilization and slightly by soil carbon sequestration. However, the first two pathways have relatively high costs compared to BECCS.

Steps	**Calculation type (€/tonne)**	**UBG plants**	**Ethanol plants**	
		Trucks (12 cases)	Trucks (22 cases)	Pipelines (10 cases)
Scenario 1	Min	74	49	25
	Average	89	73	44
	Max	100	98	70
No. of feasible cases		**6**	**19**	**9**
		25 (out of 34)		
Scenario 2	Min	72	44	24
	Average	90	60	46
	Max	99	92	79
No. of feasible cases		**10**	**20**	**9**
		30 (out of 34)		
Scenario 3	Min	79	53	31
	Average	88	80	58

	Max	96	100	88
No. of feasible cases		**3**	**11**	**9**
		14 (out of 34)		

Table 9: Shows the feasibility of the number of cases in the three scenarios with a range of min, average, and max costs included (MACC costs).

If the costs estimate from this study are used to represent BECCS for comparison with other CDR`s costs in Table 9, then the BECCS would be even more competitive and striking. See BECCS (1), BECCS (1a), and BECCS (1b) in Table 9 and Figure 47. Moreover, In a situation, if the feasibility limit is set at 167 €/tonne as stated in table 9 instead of 100 €/tonne, then 95% of the cases (truck transportation) in the three scenarios combined would be described as feasible. For the pipelines, 100% of the cases in all three scenarios would be considered feasible.

According to Geden et al., 2019, the EU can increase the abatements up to 1 Gt $CO_2.year^{-1}$ by 2050 through the deployment of BECCS in the power sector. Given the improvement of the CCS technologies, the development of the farming processes (more sustainable), policy incentives, and updating the ETS to include negative emissions, BECCS can become a highly ambitious approach to achieve plausible negative emissions even before 2050. Subsequently, achieving the targets by the end of the century towards the 1.5 °C or 2 °C could be even more feasible than thought.

No.	**CDR technologies**	**Abatement Cost US$/tonne**	**Abatement Cost €/tonne**	**Potential in 2050 ($GtCO_2$/year)**
1	BECCS	<200	<167	0.5 to 5
2	Afforestation & Refforestation	5 to 50	4 to 42	0.5 to 3.6
3	Soil carbon sequestration	0[a] to 100	0 to 84	2.3 to 5.3
4	biochar	30 to 120 [b]	25 to 100	0.3 to 2
5	Enhanced weathering (EW)	50 to 200 [c]	42 to 167	2 to 4[c]
6	Ocean alkalinization	14 to >500	12 to >418	0.1 to 10
7	Direct air carbon dioxide capture and storage (DACCS)	100 to 300	84 to 251	-
8	Ocean fertilization	2 to 457	2 to 382	<1 to 44
1a	BECCS [(ethanol and UBG) + CCS] in 2021	101	84	0.006 [d,e]
1b	BECCS [(ethanol and UBG) + CCS] in 2021	101	84	0.5 [f]

Table 10: Shows the abatement cost range of Carbon Dioxide Removal and global potentials up to 2050—source: Allen et al., 2018 (IPCC). The values are based on literature reviews, and most of these values are cited or updated from Fuss et al., 2018 by IPCC. The costs are converted to € using Xe.com directly.

[a] In the resource, it is -45 due to co-benefits. However, 0 is from Erbach and Victoria, 2021.
[b] it is 90 to 120 US$ in Erbach and Victoria, 2021.
[c] based on values from Erbach and Victoria, 2021.
[d] based on 5.6 billion of renewable ethanol from ePURE members only in 2019 (4.44 Mt CO_{2_bio}). Source: ePURE, 2021b.
[e] Based on 1.2 Billion m^3 biomethane production in the European Union in 2015 (1.42 Mt CO_{2_bio}). Source: Scarlat et al., 2018. Assumptions, 40% CO_2, and 0.9 recovery ratio. Together with ethanol, the current potential in Europe is 5,86 Mt annually or 0.00586 Gt CO_{2_bio}.
[f] based on using the lower end of No.1 (BECCS) in the table.

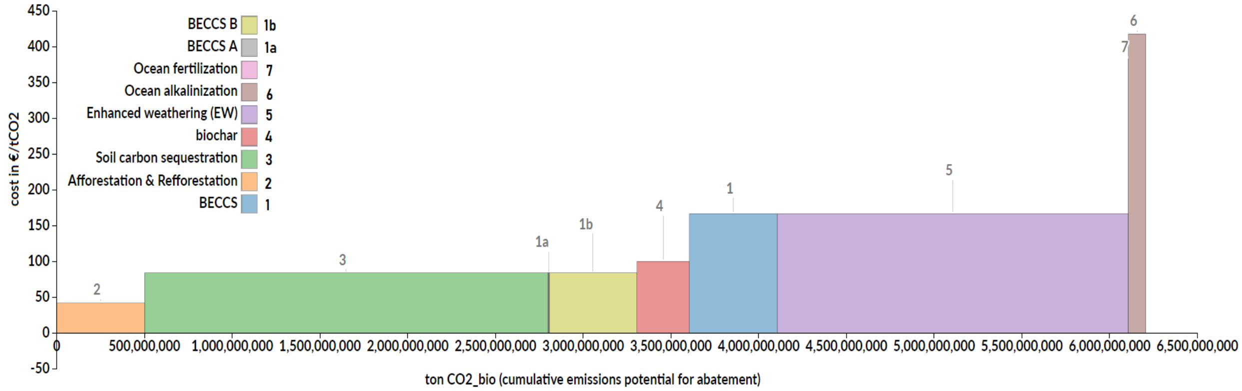

Figure 47: Shows various CDR technologies and the abatement potentials in Gt CO2 per year in 2050. 1a is the current potential (2021). Source: Allen et al., 2018 (IPCC)

5.1.1 Economic evaluation of the cases based on EU ETS

Besides costs, the cases were checked for the possibility to pay off the investments or even achieve benefits through the carbon trade (See sections 2.2.5 and 3.2.5). Since the current carbon market price is 44€/tonne (April 2021), according to Ember, a very conservative cost of just 50 €/tonne is used firstly for all three scenarios, i.e., the conservative scenario. Second, at the current pace (+10.7 €) in the first quadrant of 2021, the carbon price would reach 76 €/tonne by the end of 2021. Afterward, if the carbon price increases by just 10 €/t each year, the price would reach 106 €/tonne by the end of 2024 on a highly conservative assumption. Therefore, a higher price of 100 €/tonne is assumed for the second scenario evaluation, i.e., the optimistic scenario.

According to Bollen, the carbon price is prospected to reach around 100 €/tonne by 2030 and maybe even higher (Personal communication. April 02, 2021). However, the ETS rules and carbon prices remain highly uncertain for the time being, also because the rules enter a new phase starting from 2021 to 2030 (phase 4) (NEA, 2020), and some changes in the rules and regulations may affect the prices in the coming years. In this senes, the Dutch emissions authority (NEA) withheld to provide predictions to carbon prices (NEA. personal communication. April 22, 2021).

Thus, given the current conditions, it would be impossible to assume a highly precise assumption about carbon market prices within ETS. Therefore, both scenarios for carbon prices are based on a conservative prediction of the carbon prices; however, the first scenario is based on current carbon market prices. In contrast, the second scenario (optimistic) is based on the minimum desired carbon price by 2025.

The two scenarios were not used to establish MACC values but instead were used to examine which cases would be covered by one or both scenario settings. The reverse processing of the NPV formula is used to investigate at what carbon prices each of the 34 cases would reach break-even costs, i.e., NPV = 0. Hence, all of the cases in the three scenarios could be checked if they would be profitable under any of the two scenarios, i.e., conservative and optimistic scenario levels are marked (see Figures 42 and 43).

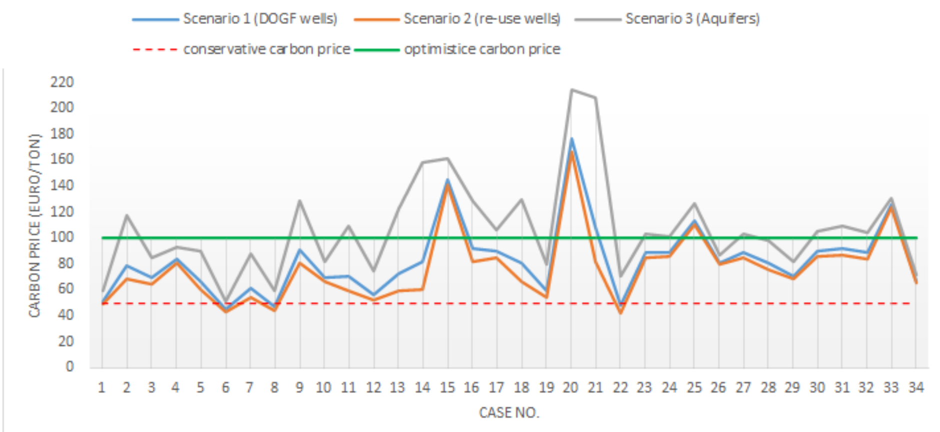

Figure 48: illustrates the break-even costs of carbon prices where NPV becomes 0 for all the cases if truck transportation is used in the three scenarios.

It can be noticed that cases #6, #8, and #22 would still be profitable in the conservative scenario, especially under scenario 2 (Figure 48). In contrast, most cases would be profitable under the optimistic scenario except four (#15, #20, #25, and #33). Nevertheless, more than half of scenario 3 would not be profitable even under the optimistic scenario where carbon prices reach 100 €/tonne CO_2 abated.

Regarding the pipeline cases, almost all of the cases would be profitable under the optimistic scenario except for case #15. Even under the conservative scenario, many of the cases, from scenario 2 and scenario 1, fall within the profitability (see Figure 49). However, given the uncertainties in the carbon market, future changes in policies, politics, climate change itself, other influential factors such as the current global crisis resulting from the Corona pandemic, and the time and the way it would end affects the uncertainties.

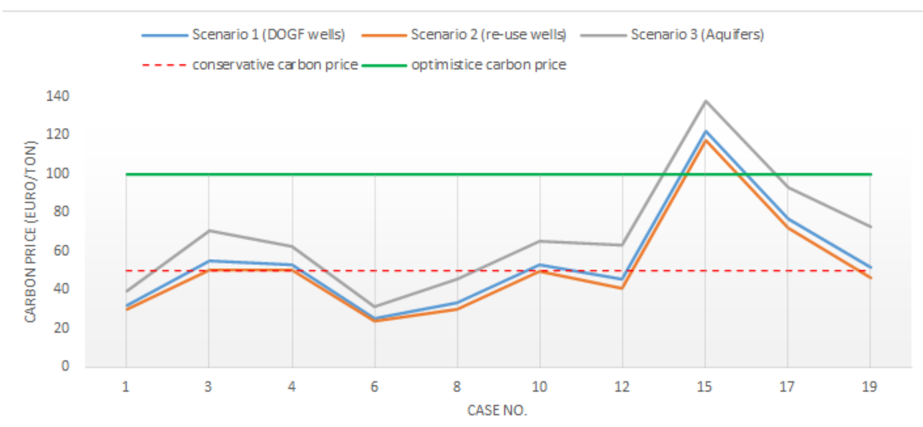

Figure 49: illustrates the break-even costs of carbon prices where NPV becomes 0 for all the pipeline cases in the three scenarios.

5.2 Methodological considerations

There are numerous points to highlight and elaborate on from the methodology; however, the most substantial is the cost data collection or calculation. The capture costs for ethanol cases is depended only on a few studies, two from 2011 and 1 from 2017 in the US. Deriving newer data from such resources makes it challenging to provide a reliable cost of the equipment, processes, and others. However, the capture CAPEX in this study is compared to a more recent in-depth study by McKaskle et al., 2018 on CAPEX calculation for CO_2 recovery from ethanol plants in the US based on three scenarios. The resulting costs from the three scenarios for non-food and beverage grade processes are compared to three cases in this study with similar annual capacity. The cases were plausibly similar with slight over or underestimation due to economies of scale - see table 8. It is remarkable to mention that economies of scale applied in this study tended to decrease the CAPEX for smaller-scale plants and increase the CAPEX for larger-scale plants.

	McKaskle et al., 2018		
Capacity (tonne/year)	24,623	98,490	328,300
Total CAPEX cost (M€)	3.4	7.74	16.0
	This study		
Capacity (tonne/year)	24,623	100,569	309,444
Total CAPEX cost (M€)	2.47	7.6	18.26

Table 11: Comparison between the capture CAPEX in this study and in-depth study by McKaskle et al., 2018 in the US

Moreover, according to McKaskel, the equipment costs average at 44% of the total costs. The larger the scale, the more expensive the equipment becomes and occupies a larger share of CAPEX. On the contrary, the equipment and unit installation costs (around 42%) act reversely, i.e., smaller-scale capacity has higher installation costs than larger-scale capacities.

CO_2 transportation plays a significant role in the overall CCS implementation. Compared to truck transportation, pipelines are more expensive in the initial investment, especially for longer distances and larger CO_2 capacity due to construction costs over a larger area for a larger pipe. However, pipeline construction is a one-time investment with annual expenses, while the truck-transportation is a continuous process. However, given the project's lifetime, the pipeline cost becomes substantially cheaper than trucks (€/tonne).

Furthermore, the number of trucks required to transport large quantities of CO_2 to remain remains a practice puzzle that needs further investigation. For instance, for case #1, around 14,065 truck trips per year (270 per week) to transport more than 300 kt of CO_2 is a crucial challenge to address whether it is practically possible. In this sense, It is imperative to mention that both CO_2 availability (capacity) and distance between the source and destination points play the most significant role in comprehending abatement's potential costs. The cost can fluctuate between the variability of both factors.

The possibility of using underground gas reservoirs was the most significant assumption made. Indeed, the storage sites are hypothetically ideal for CO_2 sequestration, even though it is technically unlikely to be used as such (Simeone Bogdan, October 20, 2020. Personal communication). Moreover, these storage sites are currently being owned by the gas companies, but not entirely (AGSI/GIE (2021). The gas companies store and withdraw gas from these reservoirs between summer and winter when the gas demand fluctuates. Bogdan Simione, the Data Analytics Advisor at GIE, denounced the possibility to store CO_2 in liquid or dense phases at these sites and that the sizes might be smaller than what is required. However, he suggested that the storage points could be used temporarily more successfully.

Despite the discouraging points mentioned, some indicators show the advantages of these storages to be used storage points for biogenic CO_2. Any of These could be commercially acquired for CO_2 storage after investigating and assessing the site for such a project.

5.3 Research challenge and limitations

The elements required to estimate the abatement costs depended mainly on main investments (CAPEX) and operation and maintenance costs (OPEX), in addition to avoided CO_2 emissions, which the latter required a partial LCA. The challenge was embodied in collecting data for those elements individually for the CCS chain, namely, capture, transportation, and storage.

The main limiting factor to the research was the dearth of data availability, especially for costs. The majority of the relevant studies in the academic library discuss BECCS projects in the US, especially for ethanol plants. Data availability imposed that some of the data be calculated theoretically, such as the biogenic emissions reporting from the facility levels. However, a theoretical methodology is usually based on assumptions that might lead to highly different outcomes than in practice. Regarding the costs, especially for the capture step, economies of scale are a simple methodology that is highly relied upon in this research because it is a simple and helpful tool to estimate costs for various equipment and productions. However, it can also lead to overestimating the costs; therefore, the average is used for the ethanol plants` capture step. Moreover, the trendline curves based on limited references create less reliable data to be generalized for specific estimations.

Another limitation of the study is the generic perspective of various costs used to represent various EU member states, even though a lot can differ from country to country. However, this obstacle is somewhat surpassed by using national-based data such as electricity emission intensity or electricity costs.

Moreover, there is a massive need for improving the literature for CCS within the bioenergy industry because a tremendous amount of literature covers the CCS for fossil-based cases leaving a vast gap for small-scale CCS, especially in the storage step. Finally, the most prominent limitation o the study is the storge assumption where underground storage sites were used to represent permanent geological reservoirs for supercritical CO_2. This is because only a limited amount of CCS facilities exist in Europe at the moment with limited existing CO_2 pipelines in Europe compared to the US.

5.4 Future consideration and researching recommendation

Various outcomes of this research can be relied upon for further studies in the future. A prominent dimension that can enrich the academic literature is the use of truck transportation that is hugely missing in the works of literature. Even though encouraging road transportation can impose negative impacts on the transportation sector, however, it is found that the annual GHG emissions from both transportation methods are highly similar. However, trucks are a much simpler method, and given the advancement of electric trucks, this can be a wide and promising method to deliver a significant amount of liquid CO_2 to storage sites or utilization, especially for the smaller amounts. Additionally, there are many factors to be considered in the future for further research improvement highlighted below.

One of the essential pivots to be considered for future development is to include a complete LCA for the mitigated emissions. This will enhance the final abatement cost for it depends highly on the abated emissions. However, for a complete LCA, the capture from the cogeneration units should also be considered, which adds value to the CO_2 quantities, increases the overall avoided emissions, and decreases overall emissions to the atmosphere.

Another crucial factor to highlight is the storage points or the injection sites that require independent deep-analysis research on their own. A practical recommendation is to survey the injection sites, whether in Europe or the US, especially for small-scale injection sites. Moreover, further researching the possibility of taking over the gas storage points for temporary or permanent CO_2 storage, especially with the advancement of renewable sources in Europe and the decrease in natural gas demand over time, is slowly phased out.

Lack of deployment of large-scale BECCS and testing the outcomes over a long period exacerbates the judgment of the technology. There is still massive uncertainty concerning BECCS, even from IPCC. The special report (summary for policymakers, 2018) and other IPCC publications do not provide a strict and decisive recommendation. Therefore, as many as BECCS projects need immediate investigation and analysis to enrich the academic library for quick consideration, at least before 2030.

5.5 motivation and drivers for BECCS

A central question that emerges while investigating the feasibility of investing in BECCS and one of the vital issues to address is the CAPEX resourcing. A more significant issue is the annual expenses needed to run the project; why would a company or corporation invest in sequestering biogenic emissions at an ethanol plant or an upgrading biogas plant. From a scientific and academic perspective, a paradigm, technology, or project is not easily differentiated as black and white; there is mostly overlap between the two that might need a long time before finalizing.

According to Bruno Gerrits (personal communication, October 27, 2020), several drivers and motivators can be considered for investment in CCS integration with bioenergy plants. First, to secure the corporate's future business because ETS is most likely expanding rather than shrinking. As an ethanol plant owner, this might be a good opportunity to invest in achieving negative emissions before the ETS coverage to either avoid penalties or better collect revenue from the carbon credits trade.

Second, a biogas plant is potentially owned by a municipality where they are usually more patient with investments and tolerating non-profitable projects than private companies. Several networks of municipalities in Europe or the world, such as Eurocities[14], C40[15], Global Covenant of Mayors for climate change[16] (GCoM), take initiatives in committing to and sign to acting towards climate neutrality. Thus, a biogas plant might receive tremendous support for curbing CO_2 and other GHG emissions. As mayor of a municipality representing a city can voluntarily, by the constitutional mandates, or is forced by, for instance, the youth demonstration, to reduce the city`s emission.

Third, as a private company, financial needs might drive sustainability initiatives in response to environmental, social governance, and corporate (ESG). A complimentary to this, is the preferential treatment and facilitates by the banks that support climate-driven projects by applying low-interest rates and long-term loans. Furthermore, as a private company, it is always advantageous to demonstrate a positive image, especially from a sustainability perspective in recent years. This will assist the company to attract the young generation and community engagement. Sustainability has become a business emblem and competition rationale where more sustainable companies are more respected and sell or export more goods.

Fourth, generally, the directories' duties is a sort of ethical or managerial responsibility that obliges, to some extent, the directors, managers, owners to take action or engage in climate-driven investments.

6.Conclusion

This study aimed to calculate the marginal abatement costs for biogenic emissions from ethanol and upgrading biogas plants in Europe. The abatement costs represent a techno-economic evaluation of CCS integration with these plants. The primary steps needed to answer the main research question entailed the calculation of CCS step costs separately. In total, 34 cases, 22 ethanol plants, and 12 UBG plants were inventoried for potential biogenic CO_2 emissions to be evaluated for abatement costs. The abatement costs are bound to several factors of a particular selection of transportation method and the type of reservoirs used for CO_2 storage. Therefore, three scenarios were constructed to evaluate the cases against different circumstances.

Results show auspicious Figures for the pipeline cases in all three scenarios and most truck-transportation cases in scenarios 1 and 2, and around 41% of the cases (plants) in scenario 3. Given the plant capacities, ethanol plants are more promising than biogas plants, even though one storage site was assigned to collect the biogas plants' emissions. Overall, Ethanol plants in this study contribute to 92% of the total gross of biogenic CO_2 in the inventory.

Transportation by pipelines is only possible for plants with an annual capacity larger than around 100 kt. Therefore, no UBG plants were eligible for pipeline transportation. All the pipeline cases were designed for ethanol plants. Theoretically, a large amount of CO_2 could be transported by road tankers and is economically feasible; however, it needs further investigation in practice.

[14] Around 196 cities in Europe; The Netherlands have eleven cities included for instance.
[15] Around 97 cities in the world. Responsible for 10,000 actions for climate change. Source: www.C40.org
[16] Include around 9,000 cities around the world.

Interestingly, both road transportation and pipelines lead to almost identical GHG emissions; therefore, any methods could be adopted from an environmental perspective

According to a strict feasibility evaluation derived from the average abatement costs from some of the well-known works of literature and a safe zone, a level of 100 €/tonne was decided. Thereby, most ethanol plants, by truck transportation, are considered feasible, while only half of the biogas plants are described as such. However, all together, feasible cases can abate around 2.5 Mt of net biogenic CO_2 annually with 77 €/tonne in scenario 1. In the same scenario, if pipelines are considered for transportation, 1.76 Mt annually can be abated for merely 44 €/tonne from nine plants only.

Abatements costs are at the minimum for truck transportations in scenario 2 where a re-usable DOGF site is used as a storage point. In contrast, scenario 3 represents the most expensive abatement option for all the cases, whether ethanol or biogas, and whether trucks are used or pipelines. This is because aquifers are three times more expensive to develop from scratch compared to DOGF.

BECCS's mitigation costs can be reasonably competitive with other CDR technologies according to IPCC`s evaluation (<167 €/tonne). However, when abatements costs from this study represent BECCS in the comparison, BECCS become even more feasible (<100 €/tonne), but the potential quantities remain uncertain for further investigation.

If ETS would be adapted to include BECCS, implementing CCS with ethanol and biogas plants could become a more favorable pathway to achieve negative emissions. With the current rise of carbon prices in the market, most of the pipeline cases examined would have reached breakeven costs soon. In contrast, with road transportation, an average carbon price of around 80 to 90 €/tonne would be needed for all of the cases to reach breakeven levels. Overall, transportation by pipelines is only possible for plants with an annual capacity larger than 100 kt approximately; however, both trucks and pipelines deliver identical amounts of net emissions. This research shows that CCS integration with ethanol and UBG plants is a cheap pathway of BECCS compared to what is already estimated by the literature, especially by IPCC, 2018. Furthermore, the inclusion of BECCS under the ETS system could assist the EU to reach its targets by 2050.

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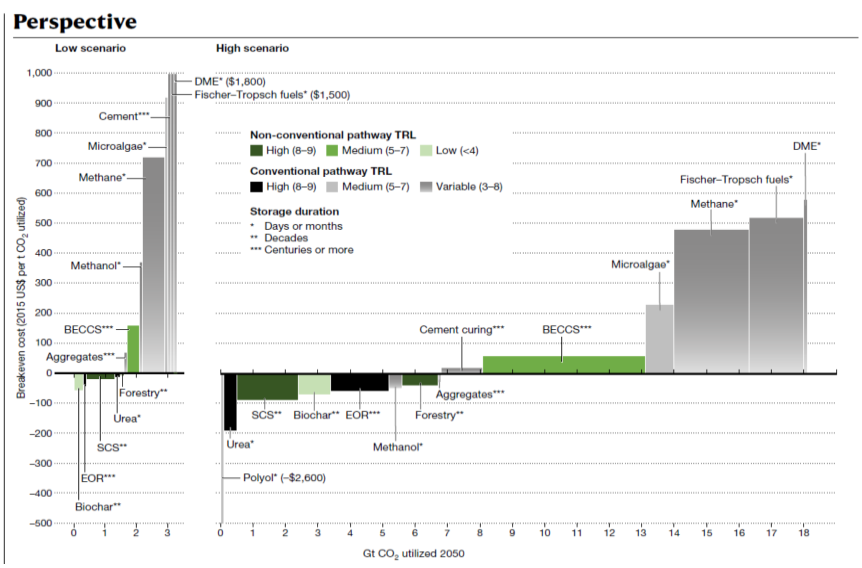
8. Appendices

A Literature review (Introduction & theory)

A.1 Estimation of breakeven cost of different pathways for CO_2 utilization in low and high scenarios (Hepburn et al., 2019. P. 8/11).



A.2 reviews the lifetimes of various project lifetimes.

Item	Lifetime (years)	Reference paper
CCS chain (fossil)	40	ZEP, 2011c
Pipeline lifetime	20	Element energy, 2010
Capital recovery factor	30 & 20	McCoy & Rubin, 2008
Capture (mixed industries)	20	Berghout et al., 2015
Intermediate storage	25	Gao et al., 2011
Pipeline project	25	Chandel et al., 2010
Refineries/power plants/flares	40	Piessens et al., 2008
Injection rate (storage)	25 to 50	Piessens et al., 2008
Pipeline project	25	Skaugen et al., 2016
Pipeline	20	Horánszky & Forgács, 2013
CO_2 supply (IGCC plant)	20	Heddle et al., 2003
CCS project (ethanol + CCS)	40	Laude et al., 2011
Pipeline operation	40	Da Silva et al., 2018

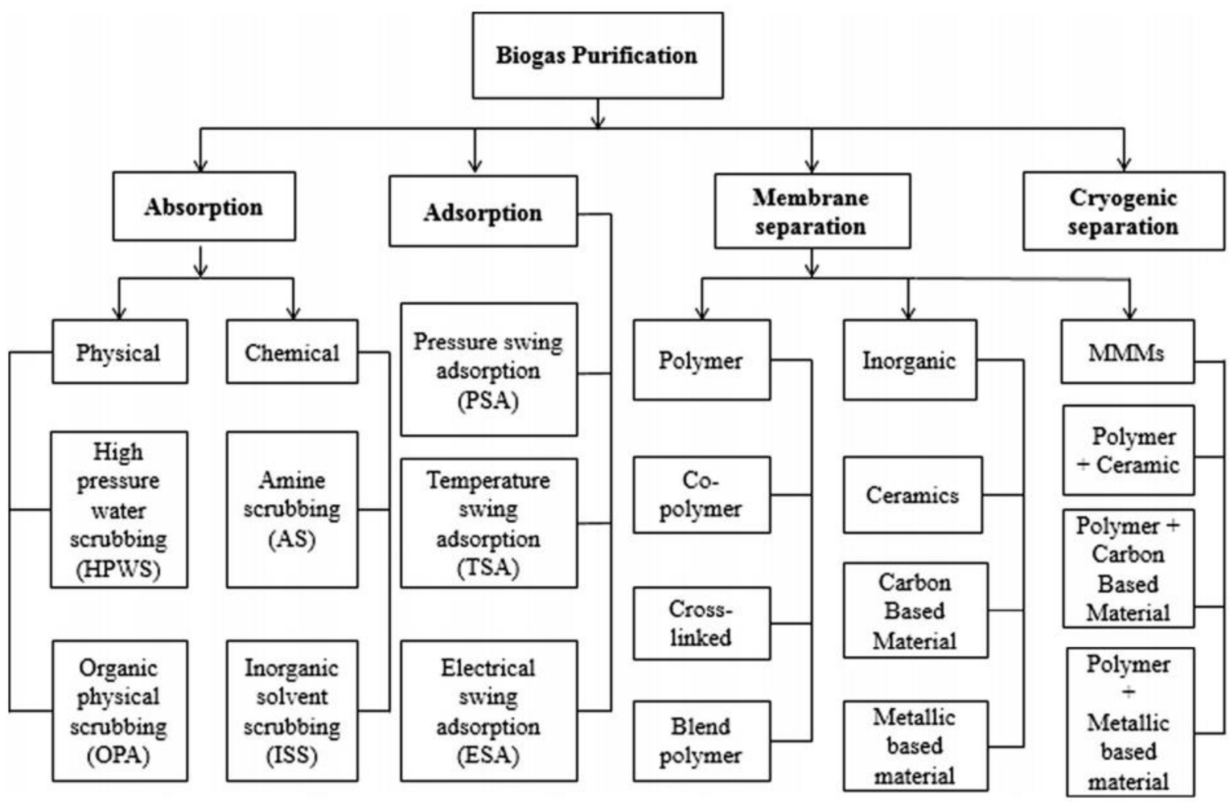
A.3 Andersons ethanol plant in Albion, Michigan in the US. Source: Toledo Balde, 2017

A.4 Main ethanol production in Europe. Source: Flach et al., (USDA/FAS) 2019).

Table 8. Fuel Ethanol Production Main Producers (million liters)								
Calendar Year	2012[r]	2013[r]	2014[r]	2015[r]	2016[r]	2017[e]	2018[e]	2019[f]
France	829	995	1,018	1,039	987	1,000	1,000	1,000
Germany	776	851	920	937	934	852	776	785
United Kingdom	215	278	329	538	658	684	684	695
Hungary	291	392	456	591	633	633	645	645
Belgium	410	451	557	557	570	620	645	645
Netherlands	451	524	519	563	443	532	563	565
Spain	381	442	454	494	328	377	522	522
Poland	213	235	181	214	241	258	259	265
Austria	216	223	230	223	224	235	235	235
Total	4,658	5,000	5,190	5,165	4,982	5,380	5,443	5,505

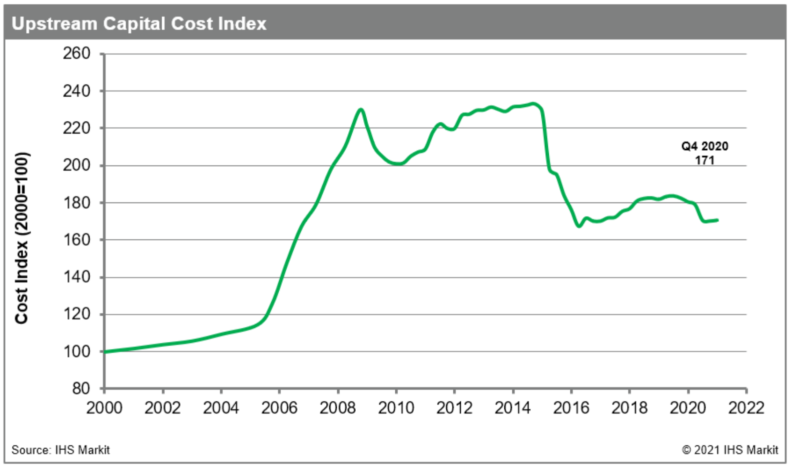
r = revised / e = estimate / f = forecast EU FAS Posts. Source: EU FAS Posts

A.5: available technologies for biogas upgrading. Source: khan et al., 2017



B Methodology (Figures and tables)

B.1 UCCI between 2000 and 2020. The previous period was between 1980 to 2001 (HIS Markit, 2021)



B.2 the output of the break-down costs of CO2 pipeline costs using FE/NETL model. It is an acronym for The Fossil Energy (FE)/National Energy Technology Laboratory (NETL)” which is an excel based model to calculate CCS costs.

Dubois et al., 2017 analyzed the CO_2 pipeline cost by breaking down the various components for a CCS project of 32 ethanol plants in the US. The design pressure ranged between a minimum of 11 MPa to a maximum of 15 MPa. On the other hand, the distances ranged between 1 km to 751 km, with an average pipeline length of 94 km. The pipeline diameters ranged from 4 inches to 16 inches. However, only the relevant data were considered for the analysis, such as the price per pump for the pipelines with diameters from 6” and smaller.

B.3: the costing by Gao et ak., 2011

The total pipe cost is calculated by $C_{Tc} = C_p \times W_{steel}/f_m$. *where* C_{TC} is the total cost in RMB in the article. f_m is the percentage of material cost to the total pipeline cost. It is 22.4% to 34.3% in the US and 50% in China.

B.4: Injection data derived from Table 4 in Carneiro et al., 2015.

Statistics	Value	Unit	Note
No of storage clusters	43	N/A	
CO_2 Minimum injectivity	0.1	Mt/year	
CO_2 Maximum infectivity	75.8	Mt/year	
Average CO_2 injectivity	11.35	Mt/year	
Spread in No. of countries	3	N/A	Spain, Portugal & Morocco
No. of locations with injectivity below 0.5 Mt/year	2	N/A	

B.5: Power Requirement of Compressors and Pumps as a Function of CO2 Mass Flow Rate. Source: McCollum and Ogden, 2006).

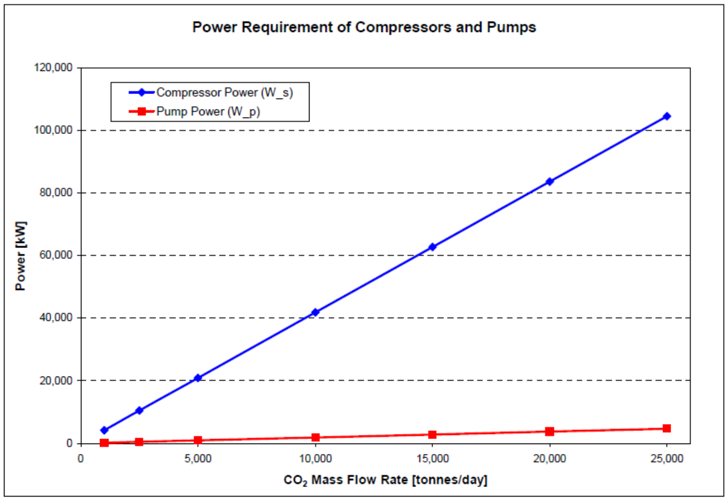
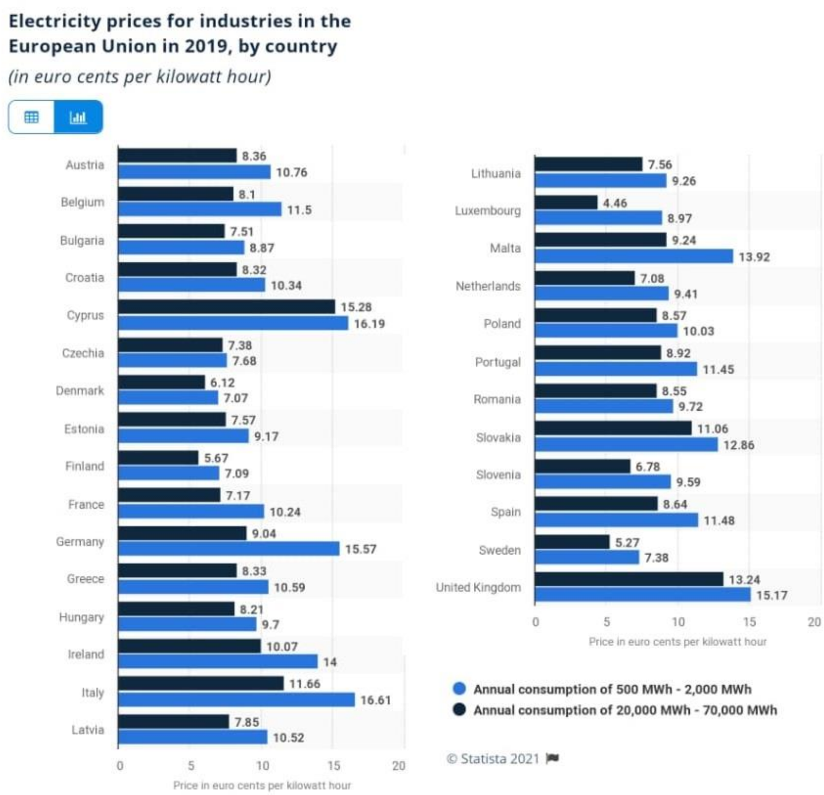


Figure 1: Power Requirement of Compressors and Pumps as a Function of CO_2 Mass Flow Rate

B.6: Industrial electricity prices in Europe in 2019. Source (Statista, 2020).



B.7 Interactive map of ethanol plants by ePURE (ePURE [image], 2021)

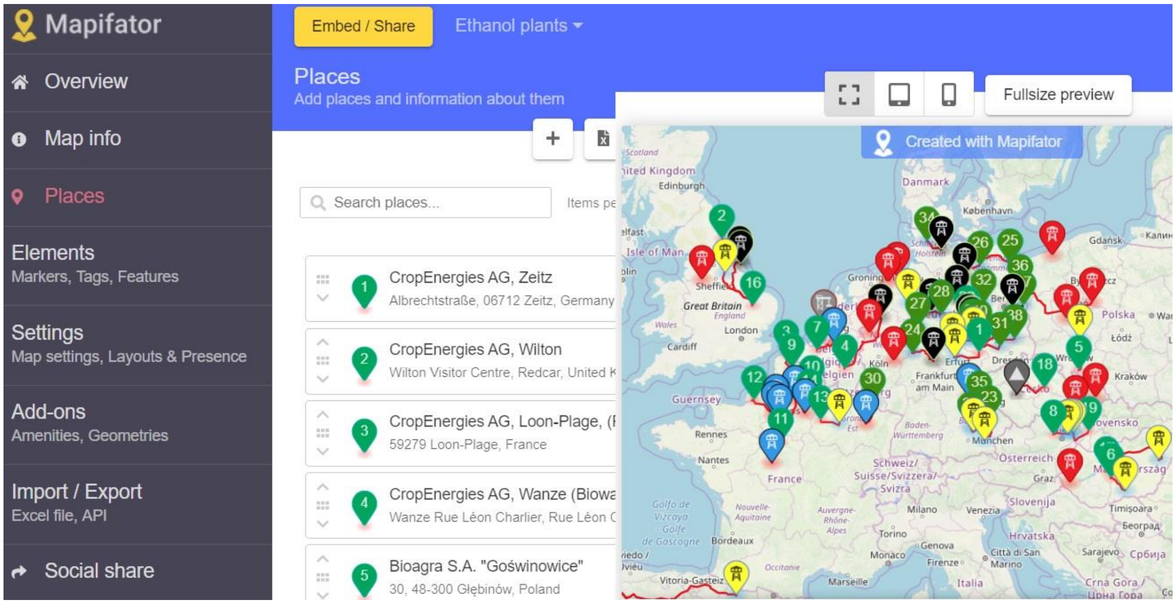
B.8 Composition of biogas compared to natural gas and landfill (Petersson & Wellinger, 2009).

		Biogas	Landfill gas	Natural gas (Danish)*	Natural gas (Dutch)
Compounds	Methane (vol-%)	60–70	35–65	89	81
	Other hydro carbons (vol-%)	0	0	9.4	3,5
	Hydrogen (vol-%)	0	0-3	0	–
	Carbon dioxide (vol-%)	30–40	15–50	0.67	1
	Nitrogen (vol-%)	~0.2	5–40	0.28	14
	Oxygen (vol-%)	0	0-5	0	0
	Hydrogen sulphide (ppm)	0–4000	0–100	2.9	–
	Ammonia (ppm)	~100	~5	0	–
	Lower heating value (kWh/Nm^3)	6.5	4.4	11.0	8.8

B.9: the difference between Normal cubic meters per two standards. Source: Mecaflux, 2021.

Standards	Pressure (bar)	Temperature (°C)	temperature Kelvin (K)	Applied
DIN 1343	1.01325	0	273.15	Yes
	Deutsches Institut für Normung or Germany Institution for Standardization			
ISO 2533	1.01325	15	288.15	No
	International Organization for Standardization.			

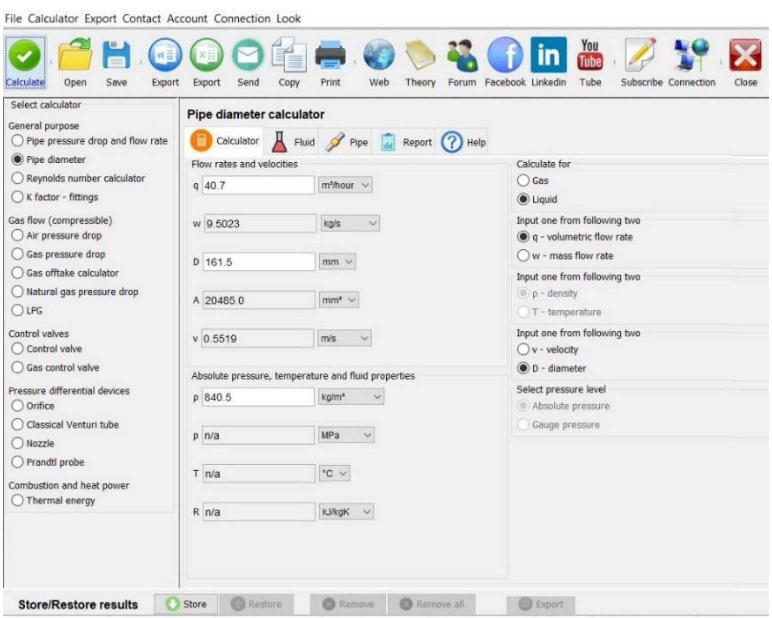
B.10: A screenshot of the software (Mapifator) interface where the pinpoints and the routes were generated. Source: Geoapify GmbH, 2019).



B.11 Den Hartogh overview (official website link)

Den Hartogh Logistics is specialized in chemical logistics (chemicals, gas, polymers, food) with over 100 years of experience. The company is active in 47 locations in 26 countries with an equipment capacity of 350 tank trailers, 625 trucks, 20,000 tank containers, and 6,100 dry bulk containers and their trailers (Den Hartogh, 2021).

B.12 PipeFlow software interface.



B.13: Some other variables used to build the customized supercritical CO2 in the PF software.

No	Items	Symbol	Unit	Value	Reference
1	Specific Isobaric heat	C, CP, CV	KJ/(kg.K)	2.434495	MegaWatSoft, 2021
				2.4425	Wischnewski, 2007
2	Dynamic Viscosity	μ	Pa.s	7.8761×10^{-5}	Wischnewski, 2007
			Centipoise (cp)	0.078761	(conversion only)
			Pa.s	7.9735×10^{-5}	Aniceto & melo, 2021
3	Molar mass	M_{molar}	kg/mol	44.01	Zêzere et al., 2018
4	Specific gas constant	R	KJ/(kg.K)	0.188923	MegaWatSoft, 2021

B.14: An overview of the existing pipeline projects for fossil-based CCS projects in various regions. Source: Peletiri et al., 2018

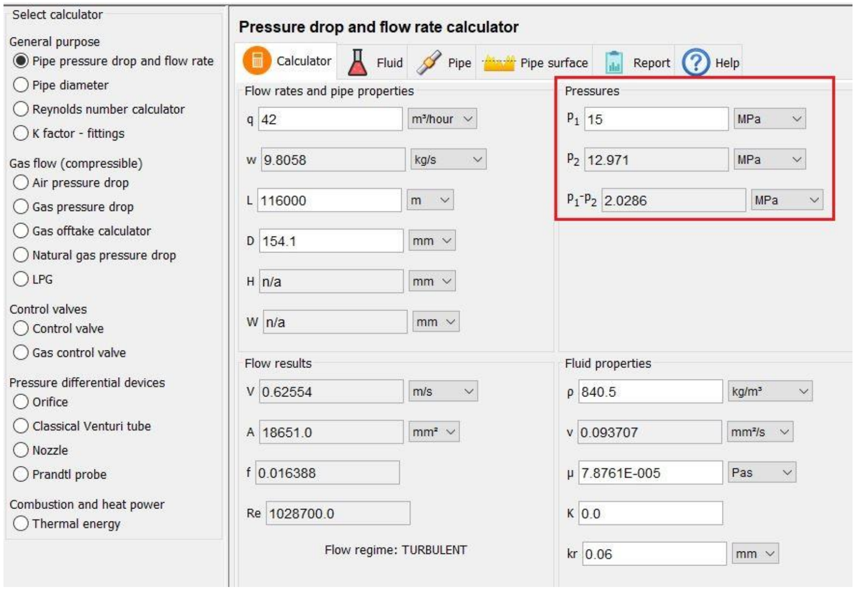
Pipeline Name	Length (km)	Capacity (Mt/y)	Diameter (mm)	Status	Country
Quest	84	1.2	324	Planned	Canada
Alberta Trunkline	240	15	406	Planned	Canada
Weyburn	330	2.0	305–356	Operational	Canada
Saskpower Boundary Dam	66	1.2		Planned	Canada
Beaver Creek	76		457	Operational	USA
Monell	52.6	1.6	203	Operational	USA
Bairoil	258	23		Operational	USA
West Texas	204	1.9	203–305	Operational	USA
Transpetco	193	7.3	324	Operational	USA
Salt Creek	201	4.3		Operational	USA
Sheep Mountain	656	11	610	Operational	USA
Val verde	130	2.5		Operational	USA
Slaughter	56	2.6	305	Operational	USA
Cortez	808	24	762	Operational	USA
Central Basin	231.75	27	406	Operational	USA
Canyon Reef Carriers	225		324–420	Operational	USA
Chowtaw (NEJD)	294	7	508	Operational	USA
Decatur	1.9	1.1		Operational	USA
Snohvit	153	0.7		Operational	Norway
Peterhead [a]	116	10		Cancelled	UK
White Rose [a]	165	20		Cancelled	UK
ROAD [a]	25	5	450	Cancelled	The Netherlands
OCAP	97	0.4		Operational	The Netherlands
Lacq	27	0.06	203–305	Operational	France
Rhourde Nouss-Quartzites	30	0.5		Planned	Algeria
Qinshui	116	0.5	152	Planned	China
Gorgon	8.4	4	269–319	Planned	Australia
Bravo	350	7.3	510	Operational	USA
Bati Raman	90	1.1		Operational	Turkey
SACROC	354	4.2	406	operational	USA
Este	191	4.8	305–356	Operational	USA

[a] Reported as planned but now cancelled.

B.15: PF interface for pressure drop calculation.

PF interface for pressure drop calculation. As shown in the red rectangle, the outlet pressure is 12.97 MPa, and the P2 is 2.02 MPa. The specific pressure for this case is 0.016. the average pipe roughness is 0.06

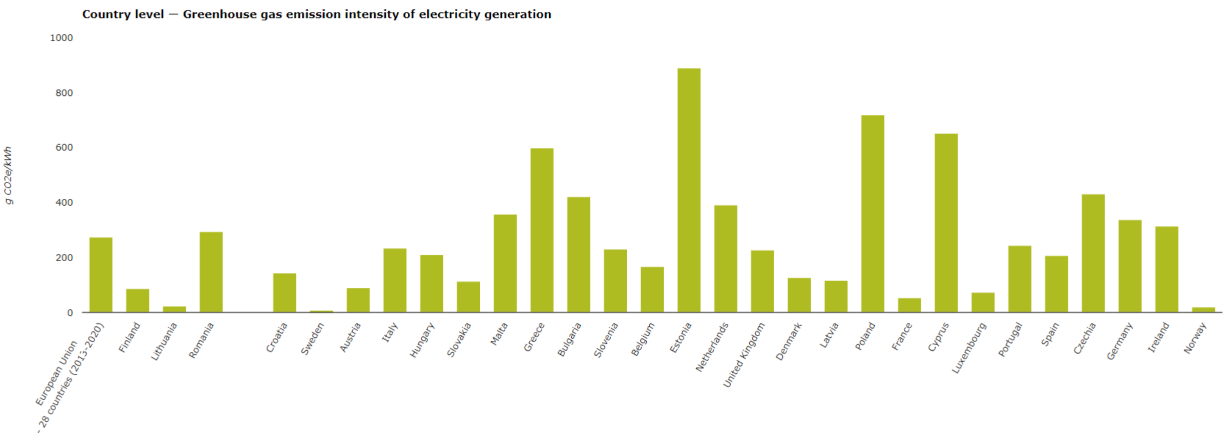
mm. The height and width of the channel are not given. The flow type is turbulent. The fluid type, pipe type, and pipe condition are chosen in the adjacent interface, but this Figure cannot be seen.



B.16: values of pipe roughness in some of the pieces of literature. In this work, the value of 0.04 mm is used.

No	Items	Symbol	Unit	Value	Reference
1	Pipe roughness (new or unused) – min/Avg./max	ε	mm	0.02/0.06/0.1	Savović, Z. (2019). PF software
2	Pipe roughness (cleaned after many years of use)	ε	mm	0.04	Savović, Z. (2019). PF software
3	Pipe roughness (after one year of use in gas pipeline	ε	mm	0.12	Savović, Z. (2019). PF software
4	Pipe roughness (New/old)	ε	mm	0.045 / 0.1	Chandel et al., 2010
5	Pipe roughness	ε	mm	0.0457	Mechleri et al., 2017
6	Pipe roughness (new pipes)	ε	mm	0.045	Peletiri et al., 2018
7	Pipe roughness (used)	ε	mm	0.045	Peletiri et al., 2018

B.17: GHG emission intensity for electricity generation per country in the EU. Source EEA, 2020b



B.18: Emission factors in g CO_2/tonne-km based on 40-44 tonnes truck illustrated against the payload and distance running empty. Source (McKinnon & Piecyk, 2010)

load tonnes	% of truck-kms run empty										
	0%	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
10	81.0	84.7	88.8	93.4	98.5	104.4	111.1	118.8	127.8	138.4	151.1
11	74.8	78.2	81.9	86.1	90.8	96.1	102.1	109.1	117.3	127.0	138.6
12	69.7	72.8	76.2	80.0	84.3	89.2	94.7	101.1	108.6	117.5	128.1
13	65.4	68.2	71.4	74.9	78.9	83.4	88.5	94.4	101.3	109.5	119.3
14	61.7	64.4	67.3	70.6	74.2	78.4	83.2	88.7	95.1	102.7	111.8
15	58.6	61.0	63.8	66.8	70.3	74.2	78.6	83.7	89.7	96.8	105.3
16	55.9	58.2	60.7	63.6	66.8	70.5	74.6	79.5	85.1	91.7	99.7
17	53.5	55.7	58.1	60.8	63.8	67.2	71.2	75.7	81.0	87.2	94.7
18	51.4	53.5	55.8	58.3	61.2	64.4	68.1	72.4	77.4	83.3	90.4
19	49.6	51.5	53.7	56.1	58.8	61.9	65.4	69.5	74.2	79.8	86.5
20	48.0	49.8	51.9	54.2	56.8	59.7	63.0	66.9	71.4	76.7	83.0
21	46.6	48.3	50.3	52.5	54.9	57.7	60.9	64.5	68.8	73.9	80.0
22	45.3	47.0	48.8	50.9	53.3	55.9	59.0	62.5	66.5	71.4	77.2
23	44.2	45.8	47.6	49.6	51.8	54.3	57.2	60.6	64.5	69.1	74.7
24	43.2	44.7	46.4	48.3	50.5	52.9	55.7	58.9	62.7	67.1	72.4
25	42.3	43.8	45.4	47.3	49.3	51.7	54.3	57.4	61.0	65.2	70.3
26	41.5	42.9	44.5	46.3	48.3	50.5	53.1	56.0	59.5	63.6	68.5
27	40.8	42.2	43.7	45.4	47.3	49.5	52.0	54.8	58.1	62.1	66.8
28	40.2	41.5	43.0	44.6	46.5	48.6	51.0	53.7	56.9	60.7	65.3
29	39.7	41.0	42.4	44.0	45.7	47.8	50.1	52.7	55.8	59.5	63.9

B.19: table of GHG emissions from the well in Banchory project in the UK

Activity	Carbon emissions t(CO_{2e})			Direct/indirect emission
	Calculated GHG emissions, expressed	Calculated GHG emissions, expressed	Calculated GHG emissions, expressed	
1. Construction (pre-operation)				
a) Site preparation				
Access roads	60–126			
Pipeline (buried)	280–589			
Well pad	60–126			
Total (land use change)	400–841			Direct
Pipeline	63			Indirect
Drill rig transport	15			Direct
b) Borehole construction				
Drill rig operation	1243	994	2486	Direct
Drilling fluids/water	10	7.5	20	Indirect
Well casing	1296	863	1944	Indirect
Borehole cement	360	324	720	Indirect
System surface elements (e.g. pump, heat exchanger etc.)	Not calculated			Indirect
2. Operation (30 year lifetime operating at 60% load)				
Pump rate (min – 14 kW)	419			Indirect
Pump rate (max – 56 kW)	1678			Indirect
Total				
Decommissioning	Not calculated			
Total				
Direct CO_2 emissions	1658–2099	1414–1832	2906–3324	Direct
Indirect CO_2 emissions	2148–3407	1677–2936	3166–4425	Indirect
Overall	3806–5506	3086–4768	6067–7767	

C. Methodology (calculations & examples)

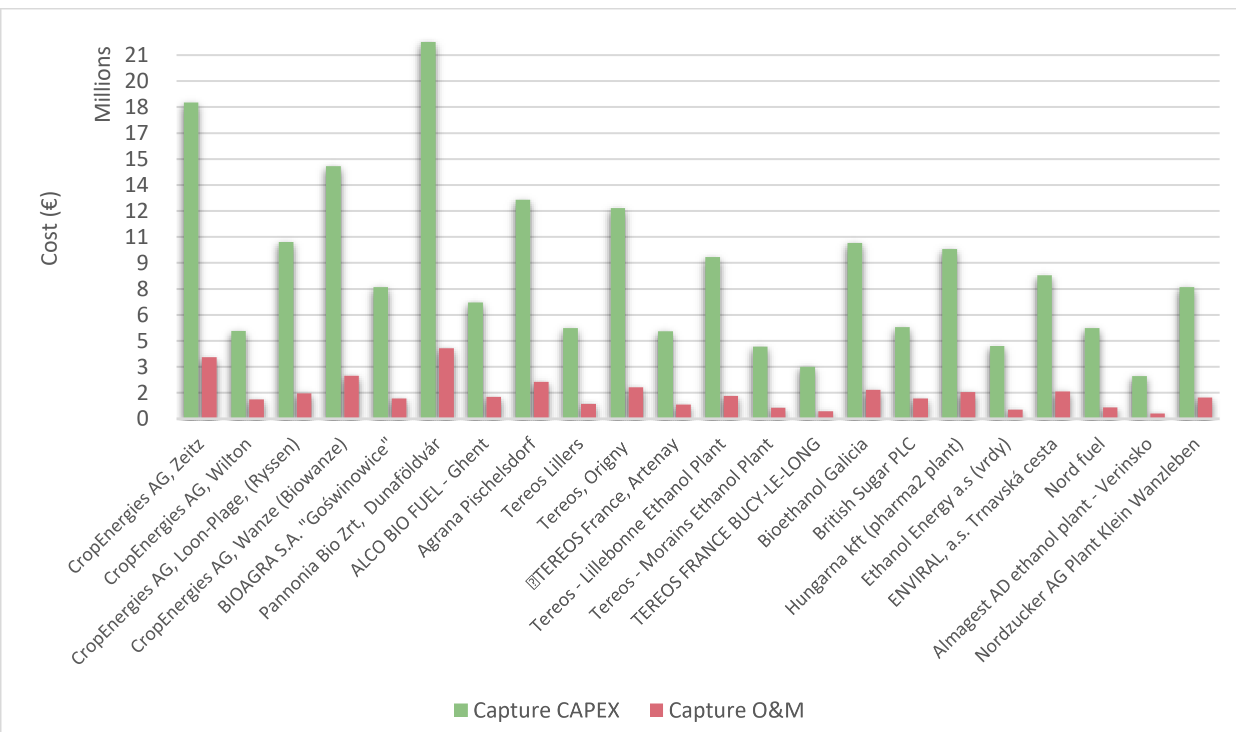
Equation No.	An example or the application of the equation
Equation (7) & (7a) case #1	W_{steel} = 0.02466 x t x (OD - t) x L W_{steel} = 0.02466 x 7.112 x (168.3 – 7.112) x 116,000 = (3279 tonnes) $C_{material}$ = 3,279 x 1000 kg x 1.4 €/kg = 4,590,960 €
Equation (9) case #1	Clabor = (941 × OD – 50.7 × OD × ln(L)) × L x Fr_labor C_{labor} = (941× 168.3 – 50.7× 168.3 × ln(116000)) × 116,000 x 1.0 = 6.828 M€
Equation (10) case #1	C_{ROW} = (217 × 0.1683 + 43.44) × 116,000x 1 = 9.3 M€ (Piessens et al., 2008) C_{ROW} = L (m) x 76 € = 116,000 x 76 = 8.8 M€ (Knoop, 2015)
Equation (11) case #1	$C_{Misc.}$ = (579x 0.1683 – 21.7 x 0.1683 x ln(116000)) x 116,000 x 1 = 6.36 M€ [based on Pieesens et al., 2008 and Knoope, 2015]
Equation (11a) case #1	$C_{Misc.}$ = 25% x ($C_{material}$ + C_{labor}) [based on Knoope, 2015] $C_{Misc.}$ = 0.25 x (4.59 M€ + 14.8 M€ = 4.84 m€
Equation (12)	$C_{storage}$ [DOGF] = nwell x (D_{drill} x C_d + C_w) + C_{sf} + C_{sd} $C_{storage}$ = 1 x (2000 x 2520 € + 0) + 1,260,00 + 2,770,000) = 9.0 M€
Equation (13) Case #1	$P_{kW} = \left(\frac{1000x10}{24x36}\right) x \left(\frac{Q\ (P_{final}-P_{cut-off}}{\rho\ x\ \eta_{pump}}\right)$ = 11.57 x $\left(\frac{847.8\ x\ (15-7.5)Mpa}{840.5\ x\ 0.75}\right)$ = 116.7 kW $Electrcity_{kWh}$ = 116.7 x 8760h = 1,022 MWh
Equation (14)	CO_2 /L_ethanol $= \frac{150{,}000 \text{ x } 10^6 \text{ (gr)}}{50 \text{ x } 10^6 \text{ x } 3.78541 \text{ (liter)}}$ = 792.5 gr CO_2/liter (ethanol/carbon intensity). 1 US Gallon = 3.78541 liters (Wight hat ltd, 2021)
Equation (14a)	ethanol/CO_2 $= \frac{50 \text{ x } 10^6 \text{ x } 3.78541 \text{ (liter)}}{150{,}000 \text{ x } 10^6 \text{ (gr))}}$ = 1261.8 liters/tonne CO_2

Equation (14) & (14a)	CO2_ethanol = (400,000 m3 x 1000 liters x 792.516 gr)/106 tonne = 317.006.4 tonnes CO2_ethanol = (400,000 m3 x 1000 liters)/ 1261.8 = 317,007 tonnes CropEnergies AG, Wilton located in the UK (400,000 M3 of ethanol)
Equation (14b) – from section 1.6.1	$180\ \mathrm{gr/kg} \xrightarrow{Fermentation} 92\ \mathrm{gr/kg}\ +\ 88\ \mathrm{gr/kg}\ CO_{2\_ethanol}$ (Elshani et al., 2018). The ratios are then, Ethanol 51.11% and 48.88%. $CO_{2\_ethanol} = \left(\frac{92\ (gr)\ x\ 100}{51.11}\right) x\ 0.4888$ = 88 grCO2 (for a 92 gr of ethanol or a 0.117 liters ethanol). Mass of 1-liter ethanol = 789.3 gr at 20 °C (NCBI, 2021 from Haynes, W. M., (2014)
Equation (15) case #2	$\upsilon_{liquid} = \frac{Q\ CO2}{\rho\_liquid} = \frac{59{,}444\ ton\ x\ 1000\ kg/ton}{1040.8}$ = 57,113 m3 Where Q is the mass of CO_2 in kg, ρ is the density of CO_2 in the liquid phase. Density in the gaseous phase is 1.9772 kg/m^3
Equation (17)	$\mathrm{V_e} = \frac{\sqrt{8\ \mathrm{x}\ \omega}}{\sqrt{\mathrm{f_D}}\ \mathrm{x}\sqrt{\rho}} = \frac{\sqrt{8\ \mathrm{x}\ 40}}{\sqrt{0.02}\mathrm{x}\ \sqrt{840.5}}$ = 4.36 m/s
Equation (18)	$\mathrm{ID} = \sqrt{\frac{4\ \mathrm{x}\ 9.812}{0.6255\ \mathrm{x}\ 3.14\ \mathrm{x}\ 840.4}} = 0.1541\ \mathrm{m}\ (154.1\ \mathrm{mm\ or}\ 6")$
Equation (20) case #1	$\Delta\mathrm{P_{per\_meter}} = \frac{8\ \mathrm{x}\ 0.02\ \mathrm{x}\ 9.18^2}{3.14^2\ \mathrm{x}\ 840.5\ \mathrm{x}\ 0.154^5}$ = 21.3 Pa/m
Equation (21) case #1	$L_{pump} = \frac{7.5}{21.3/(1000\ km)} = 352.11\ \mathrm{km}$
Equation (21a) case #1	$N_{pump} = \frac{L}{L_{pump}} = \frac{116}{352.11} = 0.33$. This means that no additional pump is required, except the one at the plant site.
Equation (21b)	$\mathrm{P_{end}} = (\mathrm{P_{max}} - (\Delta\mathrm{P_{per\_meter}}\ \mathrm{x}\ (\mathrm{L}-\ \mathrm{N_{pump}}\ \mathrm{x}\ \mathrm{L_{pump}})$ [where pressure is in Pascals, L is in meters.
Equation (21b) case #15	= $(15\mathrm{x}10^6\ \mathrm{Pa} - (27.67\ \mathrm{Pa/m}\ \mathrm{x}\ (636\ \mathrm{km}\ \mathrm{x}\ 1000 - 2\ \mathrm{x}\ 271.02) = 12.4\ \mathrm{MPa}$
Equation (22a) case #1	$\mathrm{f_D} = 1.325/([\ln\ (0.04\mathrm{mm}/3.7\mathrm{x}154{,}1\mathrm{mm}) + (5.7/1028700\text{^}0.9\ )\ ]\text{^}2\ )$ = 0.015
Equation (22) and equation (23) case #1	1/(2*√fF) =-2*LOG((0.04/(154.1*3.7)-(5.02/1028700) *LOG((0.04/154.1*3.7) - 5.02/1028700) *LOG(0.04/154.1*3.7) +13/1028700))) = 8.143 F_F = 0.00377 Since $f_D = 4\ x\ f_{F,}$ then F_D = 0.015
Equation (24) case #1	$Re = \frac{\rho\ x\ \mathrm{V}\ x\ ID}{\mu}$ $\mathrm{Re} = (840.5\ \mathrm{kg/m3}\ \mathrm{x}\ \ 0.62554\ \mathrm{m}\ \ \mathrm{x}\ 0.1541\ \mathrm{m}\ )/(4.87\ \mathrm{x}\ 10\text{^}(-5)\ )$ = 1,673,879 { the value of 1028700 “from PF software”is used in equation 16]
Equation (25) case #1	$\mathrm{t} = \frac{15\ \mathrm{MPa}\ \mathrm{x}\ 168.3\ \mathrm{mm}}{2\ \ \mathrm{x}\ 240\ \mathrm{MPa}\ \mathrm{x}\ 1\ \mathrm{x}\ 0.72} = 7.3\ \mathrm{mm}$

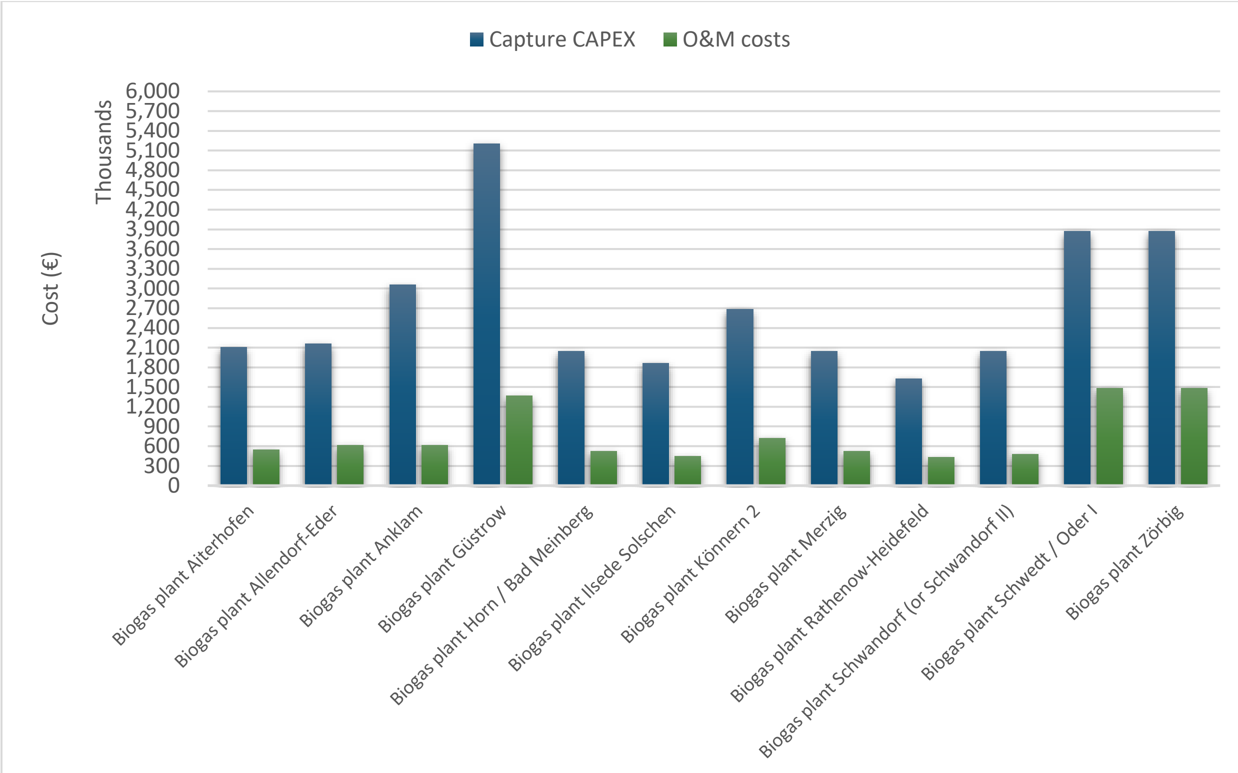
3.1.1a Case #2 from Equation (4)	$\mathrm{CAPEX}_{Capture} = 4.157 \text{ x } 10^{6} \left(\frac{59444}{59000}\right)^{0.67}$ = 5 million Euros [method 1]
3.3.1a Case #2	$\mathrm{CAPEX}_{capture}$= (380.96 x 59,444$^{-0.135}$)*59,444 = 5.1 million Euros [method 2]
3.3.1b Case #2	$\mathrm{CAPEX}_{capture}$= 24706 x 2100$^{0.5809}$ = 2.10 million Euros [2100 is the raw biogas flow capacity of case #23 (Aiterhofen biogas plant)
3.3.1b Case #2	$C_{\#23}$ = =8602.3 x 13747$^{0.5809}$ = 2.18 million Euros [13,747 is the annual mass of biogenic CO_2 of case #23 (Aiterhofen biogas plant)
Table 2 Case #23	Distnace = 114 km, 2 way distance = 228 km. Total cost = 100 € + 1.8 € x 114 + 100 + 1.8 € x 114 + 800 € = 690.4 €/truck (or 22 tonne CO_2 Annual mass of CO_2 from the plant = 14,343 tons. No. of trucks per year = 652 approximately. Annual transportation cost = 652 x 690.4 € = 450,141 €
3.1.2b.2 labor cost 2nd method Case #1	C_{labor} = L (m) x OD (m) x 756 € [area based method, and 756 = fixed price] C_{labor} = 116 x 1000 x (168.3/1000) x 755.56 € = 14.8 million euros C_{labor} = OD (inch) x L (m) x 19.24 € [pipe size based method] C_{labor} = 168.3mm/25.4” x 116 x 1000 x 19.24 € = 14.8 million euros

D. Results

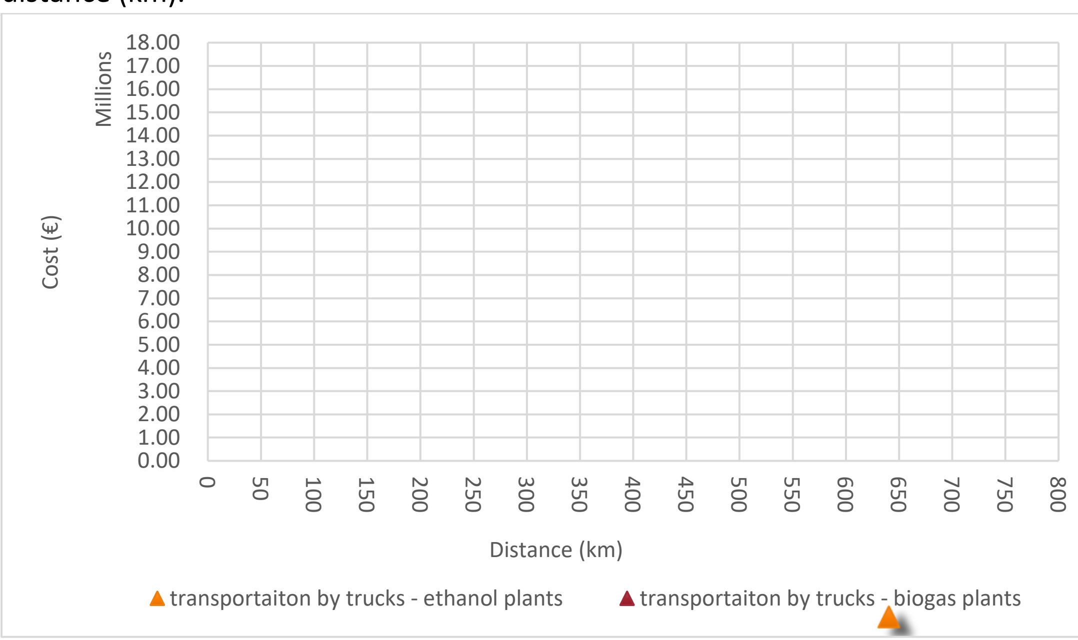
D.1 Illustration of capture CAPEX and O&M for ethanol plants



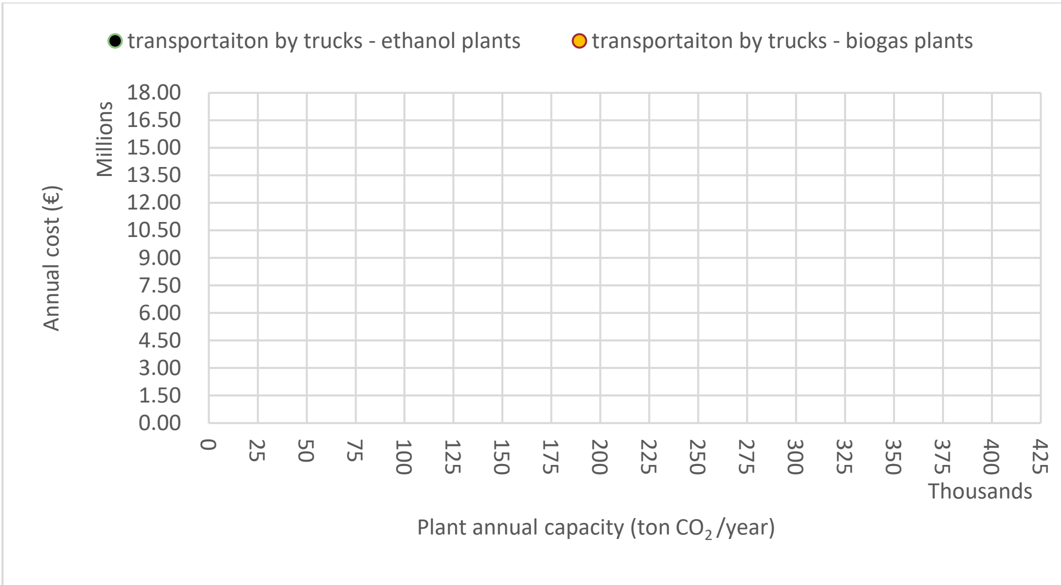
D.2 Illustration of Capture CAPEX and O&M for upgrading biogas plants



D.3: Annual transportation cost by trucks for ethanol and biogas plants plotted against the distance (km).



D.4: Annual transportation cost by trucks for both ethanol and biogas plants plotted against the capacity

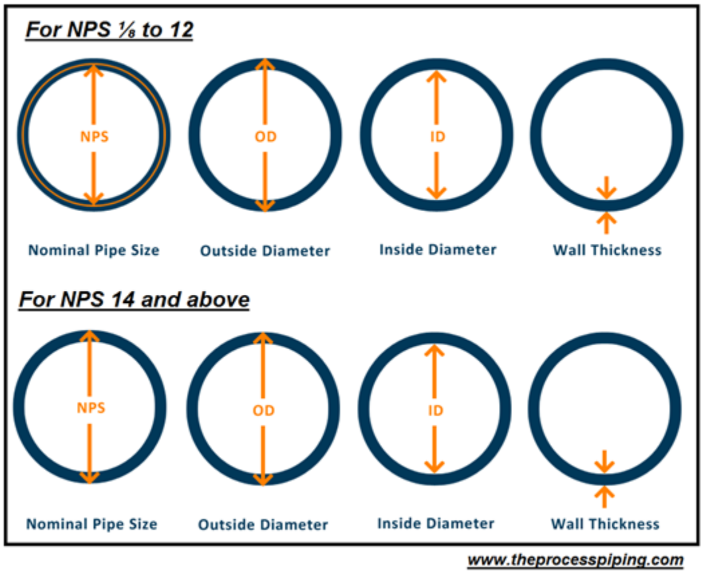


:. See Appendix D.3 for the CAPEX plotting against distances in Appendix D.3

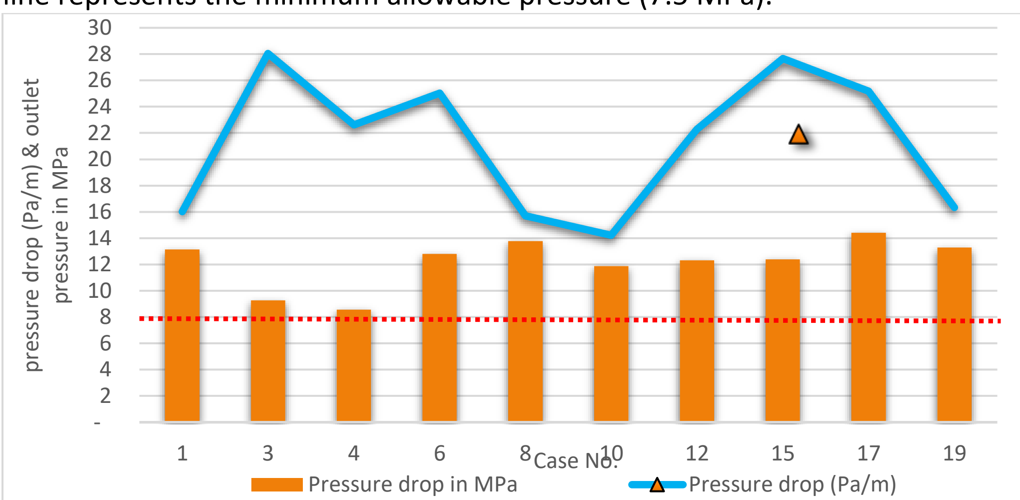
D.5: Complete list of the pipelines which includes pipeline`s ID and OD, schedules, Flow rate, wall thickness and cross section of the pipes.

No	Ethanol and biogas plants	tons of CO2/a (1 bar & 0°C for biogas & ethanol (gaseous CO2 at density of 1.9772 Kg/M3	Volume in liquid form (M3), density = 840.5 Kg/M3) at 31 C & 15.0 Mpa	Volume Flow rate (M3/h)	Volume Flow rate (M3/s)	Mass flow rate (kg/s)	Pipe sch	Pipe inner diamter (mm)	Pipe outer diamter (mm)	Nominal pipesize	Velocity (m/s)	Pipe cross section area [mm²]	wall thickness (mm)
1	CropEnergies AG, Zeitz	309,444	368,166	42.0	0.0117	9.812	Sch40	154.10	168.30	6" NPS150	0.6255	18651.00	7.112
3	CropEnergies AG, Loon-Plage, (Ryssen)	146,986	174,879	20.0	0.0055	4.661	Sch40	102.30	114.30	4" NPS100	0.6759	8219.40	6.02
4	CropEnergies AG, Wanze (Biowanze)	232,083	276,125	31.5	0.0088	7.359	Sch40	128.20	141.30	5" NPS125	0.6779	12908.00	6.553
6	Pannonia Bio Zrt, Dunaföldvár	386,804	460,208	52.5	0.0146	12.265	Sch40	154.10	168.30	6" NPS150	0.7819	18651.00	7.112
8	Agrana Pischelsdorf	193,402	230,104	26.3	0.0073	6.133	Sch40	128.20	141.30	5" NPS125	0.5660	12908.00	6.553
10	Tereos, Origny	184,000	218,917	25.0	0.0069	5.835	Sch40	128.20	141.30	5" NPS125	0.5380	12908.00	6.553
12	Tereos - Lillebonne Ethanol Plant	131,000	155,860	17.8	0.0049	4.154	Sch40	102.30	114.30	4" NPS100	0.6016	8219.40	6.02
15	Bioethanol Galicia	146,000	173,706	19.8	0.0055	4.630	Sch40	102.30	114.30	4" NPS100	0.6692	8219.40	6.02
17	Hungarna kft (pharma2 plant)	139,250	165,675	18.9	0.0053	4.416	Sch40	102.30	114.30	4" NPS100	0.6387	8219.40	6.02
19	ENVIRAL, a.s. Trnavská cesta	112,173	133,460	15.2	0.0042	3.557	Sch40	102.30	114.30	4" NPS100	0.5137	8219.40	6.02

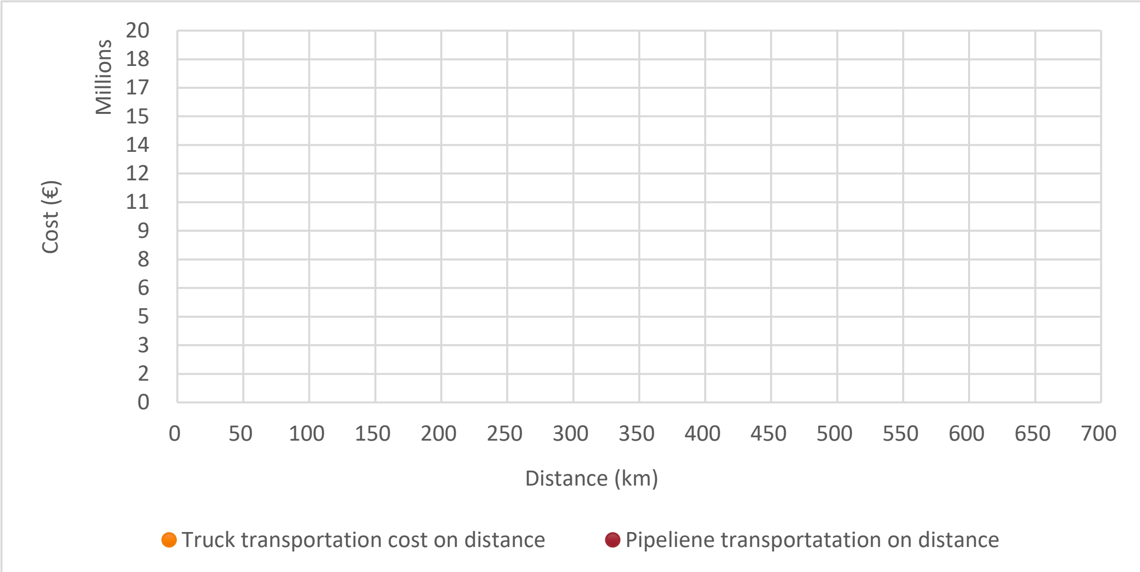
D.6 Nominal pipe sizes and Inside and Outside diameters. Source: Van der Watt, B. (2020, January 14). www.techsteel.net; referenced from www.theproccesspiping.com



D.7: Illustration of pressure drop and the outlet pressure for the pipeline cases. The dashed red line represents the minimum allowable pressure (7.5 MPa).



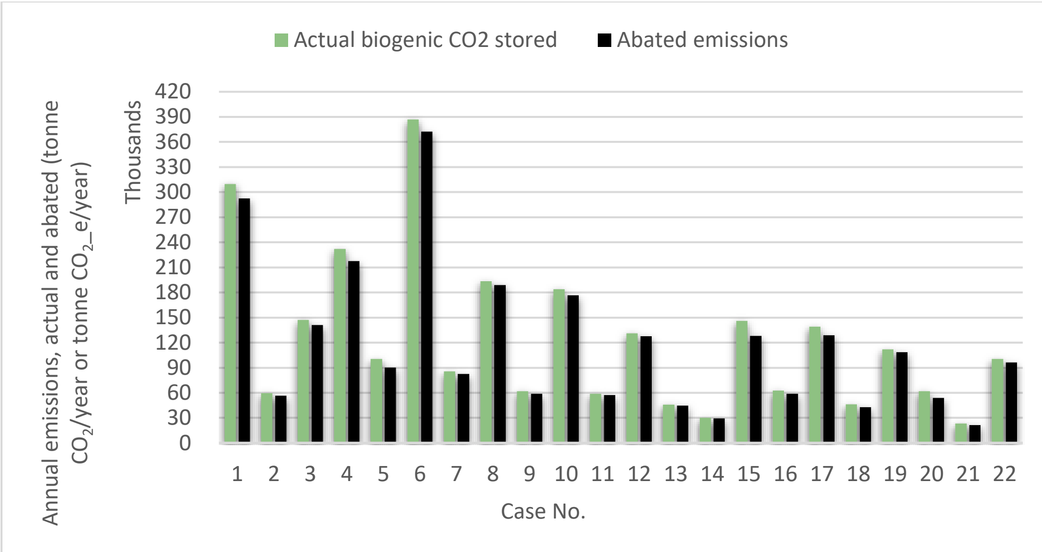
D.8: Shows the transportation cost plotted on the capacity axis for both methods, trucks and pipelines.



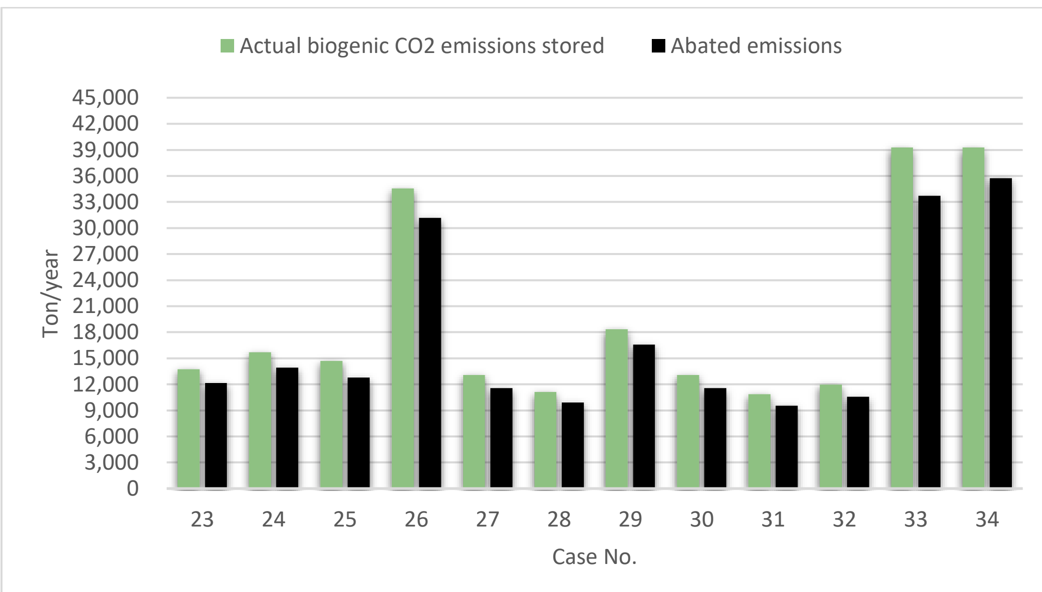
D.9: Biogenic point sources and their assigned individual storage points. Link to Mapifator.

No	Ethanol and biogas plants	Appointed storage point	technical storage size in (million M3)	20 years cumulative volume of supercrticial phase CO2 (M3), density = 840.5 Kg/M3)
1	CropEnergies AG, Zeitz	Kirchheiligen (DGF)	177.24	7,363,320
2	CropEnergies AG, Wilton	Aldbrough (Salt cavern)	190.35	1,414,480
3	CropEnergies AG, Loon-Plage, (Ryssen)	Gournay-sur-Aronde (Aquifer)	1175.44	3,497,577
4	CropEnergies AG, Wanze (Biowanze)	Epe Uniper H-Gas (Salt cavern)	1342.11	5,522,490
5	BIOAGRA S.A. "Goświnowice"	Wierzchowice (DGF)	1157.89	2,393,079
6	Pannonia Bio Zrt, Dunaföldvár	Zsana (DGF)	2036.84	9,204,150
7	ALCO BIO FUEL - Ghent	Loenhout (Aquifer)	789.47	2,038,456
8	Agrana Pischelsdorf	Tallesbrunn (DGF)	396.49	4,602,075
9	Tereos Lillers	Saint-Clair-sur-Epte (Aquifer)	365.13	1,472,664
10	Tereos, Origny	Beynes Profond & Supérieur Aqui	681.29	4,378,346
11	TEREOS France, Artenay	SEDIANE LITTORAL: Chémery (Aq	1456.14	1,403,926
12	Tereos - Lillebonne Ethanol Plant	Saint-Illiers-la-Ville (Aquifer)	340.64	3,117,192
13	Tereos - Morains Ethanol Plant	Trois Fontaines l'Abbaye (DGF)	365.13	1,094,587
14	TEREOS FRANCE BUCY-LE-LONG	Germigny-sous-Coulombs (aquifer)	365.13	713,861
15	Bioethanol Galicia	Carriço (Salt cavern)	1367.54	3,474,123
16	British Sugar PLC	Atwick (Salt ca.)	200.88	1,493,195
17	Hungarna kft (pharma2 plant)	Hajdúszoboszló (DGF)	1539.47	3,313,494
18	Ethanol Energy a.s (vrdy)	Háje (Crystalline Structure)	419.74	1,104,498
19	ENVIRAL, a.s. Trnavská cesta	Láb complex (DGF)	1954.39	2,669,204
20	Nord fuel	Gatchinskoye (Aquifer)	193.86	1,475,312
21	Almagest AD ethanol plant - Verinsko, Bulgaria	Chiren (DGF)	550.00	552,249
22	Nordzucker AG Plant Klein Wanzleben	Stassfurt (Salt cavern)	639.47	2,393,079
23	Biogas plant Aiterhofen	Bad Lauchstädt (DGF)	586.84	327,111
24	Biogas plant Allendorf-Eder			373,841
25	Biogas plant Anklam			350,039
26	Biogas plant Güstrow			822,590
27	Biogas plant Horn / Bad Meinberg			311,534
28	Biogas plant Ilsede Solschen			264,804
29	Biogas plant Könnern 2			436,148
30	Biogas plant Merzig			311,534
31	Biogas plant Rathenow-Heidefeld			258,573
32	Biogas plant Schwandorf (or Schwandorf II)			284,431
33	Biogas plant Schwedt / Oder I			934,603
34	Biogas plant Zörbig			934,603
		Total	18,291	70,301,169

D.10: Shows the actual CO_2 stored (tonnes/year) and the abated emissions (tonnes/year) for the ethanol cases



D.11: Shows the actual CO_2 stored (tonnes/year) and the abated emissions (tonnes/year) for upgrading biogas plants



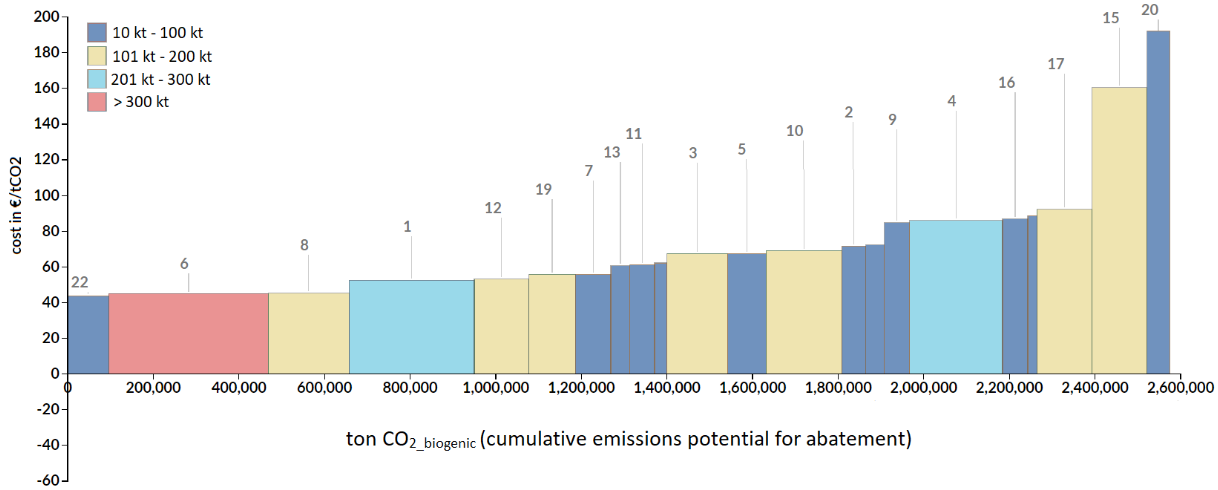
D.12 (left): Shows MACC results in Scenario 1: truck and pipeline transportation, DOGF storage types. Pipeline CAPEX is calculated using Piessens et al., 2008. The green cells represent the economic evaluation of three categories, Appealing (20€ - 50€)/tonne abated, Viable (51€ - 80€)/tonne abated, and Fair (81€ - 100€/tonne abated. The red cells refer to the disadvantage of the cases.
D.13 (right): Shows MACC results in Scenario 2: truck and pipeline transportation, DOGF Re-use storage types. Pipeline CAPEX is calculated using Knoope, 2015.

	Scenario 1 (DOGF wells)						Scenario 2 (re-use wells)					
	Truck transportation			Pipeline transportation - Piessens			truck transportaiton			Pipeline transportation - Knoope method		
Case #	Total Capex per Case (truck transportation & DOGF well)	Total O&M	MACC	Total Capex (Pipeline + DOGF well)	Total O&M	MACC	Total Capex per Case (truck transportation & DOGF well)	Total O&M	MACC	Total Capex (Pipeline (Knoope) + DOGF well)	Total O&M	MACC
1	27,331,319	13,975,106	55	55,483,966	5,166,744	31	22,207,319	13,718,906	53	56,341,540	5,089,991	31
2	14,142,182	3,645,423	83				9,018,182	3,389,223	72			
3	19,281,997	8,751,417	72	53,691,596	3,056,073	50	14,157,997	8,495,217	68	58,572,848	3,100,030	53
4	23,648,749	17,602,994	89	78,960,535	4,767,325	48	18,524,749	17,346,794	86	90,021,787	4,996,682	53
5	16,678,588	5,508,077	75				11,554,588	5,251,877	68			
6	30,828,526	15,141,860	47	52,745,995	5,430,435	25	25,704,526	14,885,660	45	51,863,522	5,301,481	24
7	15,791,489	4,085,866	63				10,667,489	3,829,666	56			
8	21,714,567	7,587,833	49	38,730,530	3,237,090	32	16,590,567	7,331,633	45	37,020,613	3,083,312	31
9	14,301,854	4,581,251	96				9,177,854	4,325,051	85			
10	21,232,712	11,267,822	73	64,717,783	3,698,934	48	16,108,712	11,011,622	69	71,492,379	3,799,692	51
11	14,113,067	3,106,747	72				8,989,067	2,850,547	61			
12	18,408,380	6,057,789	58	39,626,726	2,499,037	43	13,284,380	5,801,589	53	39,861,234	2,403,592	42
13	13,236,189	2,380,960	75				8,112,189	2,124,760	61			
14	12,075,181	1,564,972	84				6,951,181	1,308,772	62			
15	19,228,732	19,770,483	165	118,630,448	5,224,218	112	14,104,732	19,514,283	160	150,683,854	6,083,340	137
16	14,357,866	4,689,783	98				9,233,866	4,433,583	87			
17	18,861,869	11,128,868	97	71,387,751	3,662,616	70	13,737,869	10,872,668	92	83,211,501	3,914,849	79
18	13,265,067	2,760,463	87				8,141,067	2,504,263	72			
19	17,349,808	5,419,574	62	36,008,065	2,690,351	50	12,225,808	5,163,374	56	35,404,948	2,569,778	48
20	14,309,088	9,926,942	204				9,185,088	9,670,742	192			
21	11,541,936	1,673,495	118				6,417,936	1,417,295	89			
22	16,678,588	3,613,886	50				11,554,588	3,357,686	44			
23	2,858,060	1,014,497	101				2,431,060	993,147	96			
24	2,915,644	1,181,402	100				2,488,644	1,160,052	97			
25	3,812,437	1,392,779	131				3,385,437	1,371,429	127			
26	5,960,614	2,370,997	90				5,533,614	2,349,647	88			
27	2,799,315	958,763	101				2,372,315	937,413	96			
28	2,615,222	704,842	91				2,188,222	683,492	85			
29	3,440,832	1,047,722	78				3,013,832	1,026,372	75			
30	2,799,315	975,902	102				2,372,315	954,552	98			
31	2,382,181	821,238	104				1,955,181	799,888	99			
32	2,799,315	851,683	100				2,372,315	830,333	95			
33	4,624,226	4,585,135	146				4,197,226	4,563,785	144			
34	4,624,226	2,289,234	74				4,197,226	2,267,884	72			

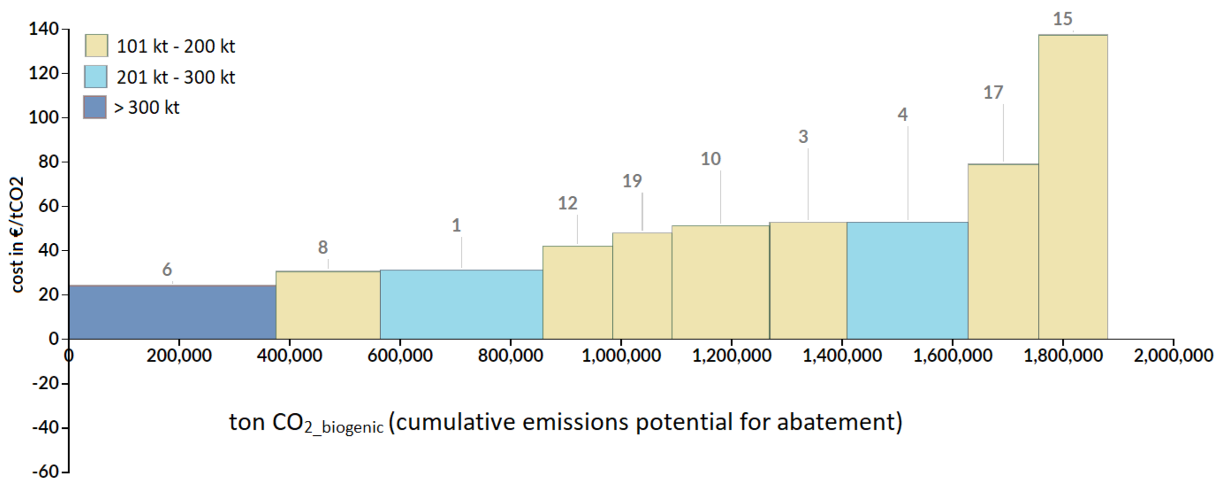
D.14: Shows MACC results in Scenario 3: truck and pipeline transportation, Aquifer storage types. Pipeline CAPEX is calculated using Piessens et al., 2008

	Scenario 3 (Aquifers)					
	truck transportaiton			Pipeline transportation - Piessens		
Case #	Total Capex per Case (truck transportation & DOGF well)	Total O&M	MACC	Total Capex (Pipeline (Piessens) + DOGF well)	Total O&M	MACC
1	45,961,319	14,906,606	63	74,113,966	6,098,244	39
2	32,772,182	4,576,923	124			
3	37,911,997	9,682,917	88	72,321,596	3,987,573	66
4	42,278,749	18,534,494	100	97,590,535	5,698,825	59
5	35,308,588	6,439,577	100			
6	49,458,526	16,073,360	53	71,375,995	6,361,935	31
7	34,421,489	5,017,366	91			
8	40,344,567	8,519,333	61	57,360,530	4,168,590	44
9	32,931,854	5,512,751	135			
10	39,862,712	12,199,322	86	83,347,783	4,630,434	61
11	32,743,067	4,038,247	112			
12	37,038,380	6,989,289	76	58,256,726	3,430,537	61
13	31,866,189	3,312,460	126			
14	30,705,181	2,496,472	163			
15	37,858,732	20,701,983	183	137,260,448	6,155,718	130
16	32,987,866	5,621,283	137			
17	37,491,869	12,060,368	115	90,017,751	4,594,116	88
18	31,895,067	3,691,963	141			
19	35,979,808	6,351,074	83	54,638,065	3,621,851	71
20	32,939,088	10,858,442	247			
21	30,171,936	2,604,995	226			
22	35,308,588	4,545,386	74			
23	4,410,560	1,092,122	116			
24	4,468,144	1,259,027	114			
25	5,364,937	1,470,404	146			
26	7,513,114	2,448,622	96			
27	4,351,815	1,036,388	117			
28	4,167,722	782,467	110			
29	4,993,332	1,125,347	90			
30	4,351,815	1,053,527	119			
31	3,934,681	898,863	125			
32	4,351,815	929,308	118			
33	6,176,726	4,662,760	152			
34	6,176,726	2,366,859	79			

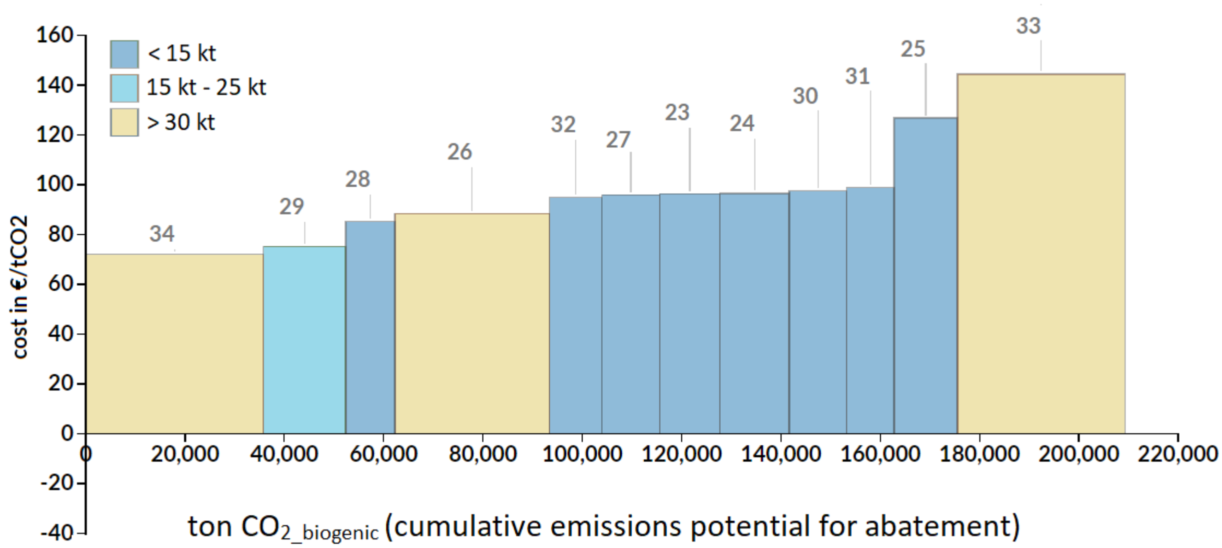
D.15: Shows Marginal Abatement Cost in Scenario 2 for ethanol plants if truck transportation is used. The numbers above histograms are case No.



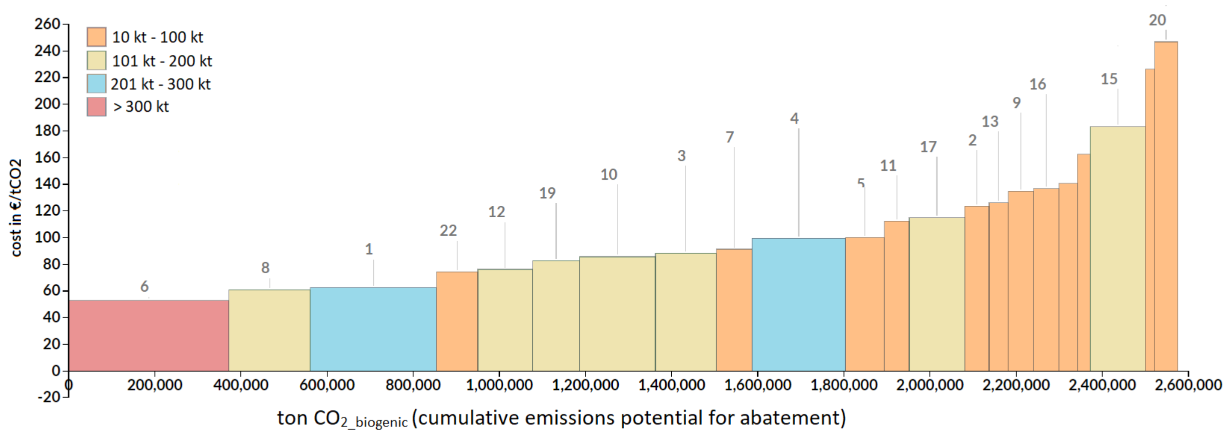
D.16: Shows Marginal Abatement Cost in Scenario 2 for ethanol plants if pipeline transportation is used



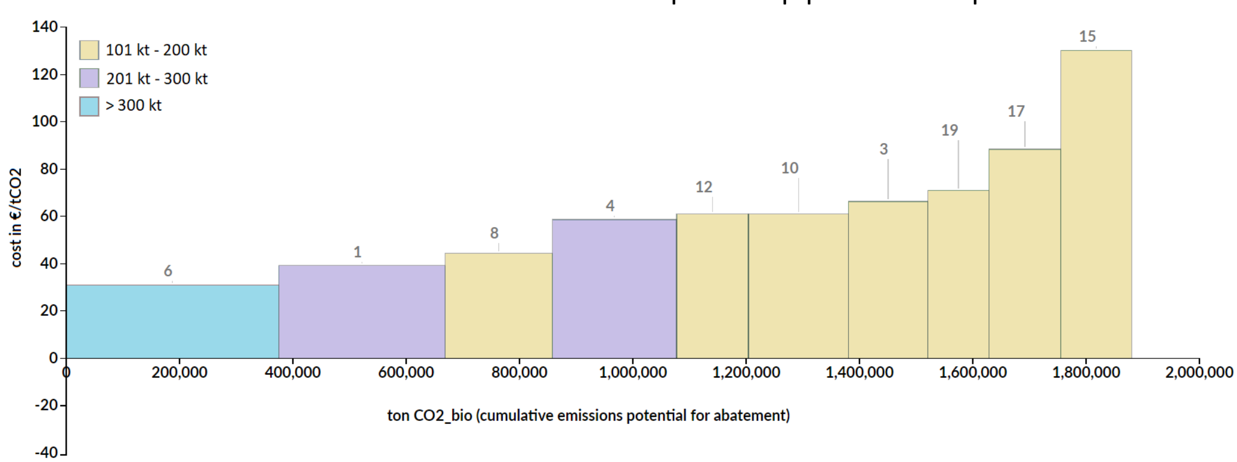
D.17: Shows Marginal Abatement Cost in Scenario 2 for UBG plants.



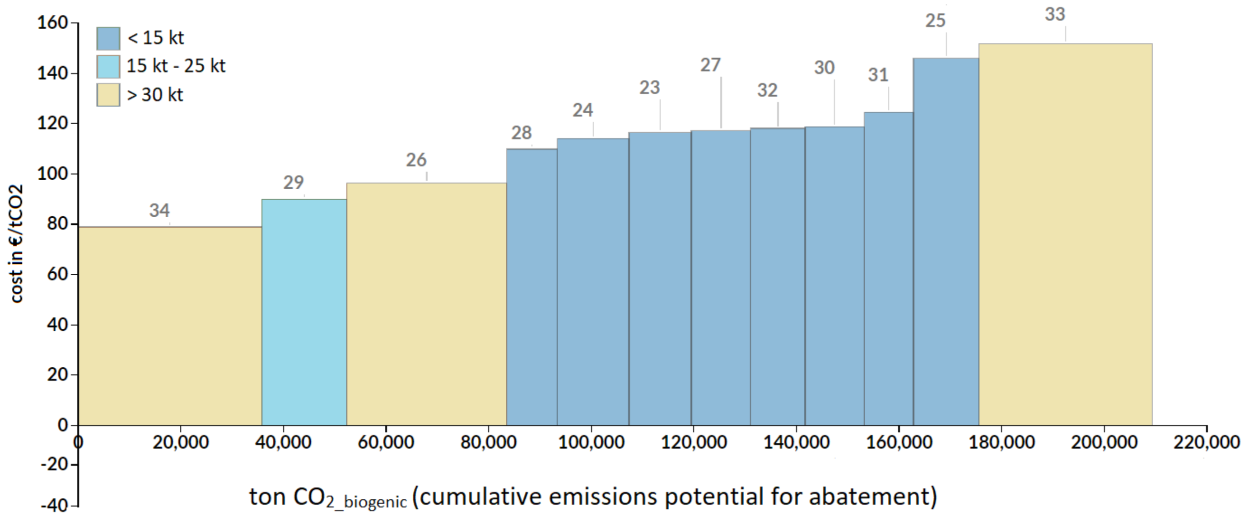
D.18: Shows MACC values in Scenario 3 for ethanol plants if truck transportation is used. The numbers above histograms are case No.



D.19: Shows MACC values in Scenario 3 for ethanol plants if pipelines transportation



D.20: Shows MACC values in Scenario 3 for UBG plants.



E. Interviews

E.1 Interview with Bogdan Simion, Data Analytics Advisor at Gas Infrastructure Europe (GIE) – October 20, 2020.

The topics included discussion about the underground storage gas locations in Europe and the possibility to use those storage sites for CO_2. Mr. Simion also elaborated on the detailed GIE map, 2018.

E.2 Interview with Bruno Guirret, Senior Client Engagement Lead in Brussels – October 27, 2020

The topics included discussing CCS in general. Although Mr. Guirret was assigned for this interview by Global CCs institute, he was not specialized in CO_2 storage. However, he provided very valuable insights into sustainability concepts and the drivers behind sustainable investments.

E.3 Interview with Wouter Siemers, Program Advisor at Netherlands Enterprise Agency (RVO.n) – January 06, 2021.

The topics included discussing the overall biogas industry and the chain of associated processes.

E.4 Interview with Dr. Robert Harmsen, Professor at the Copernicus Institute, Utrecht University – January 06, 2021.

Dr. Harmsen provided valuable advice on the topics discussed, such as Net Present Values (NPV), Marginal Abatement Cost Curves (MACC), ETS market and other tools needed for calculations used in this thesis.

E.5 Interview with Jacob Limbeek, Independent utility professional (Ocap and Linde gas) – January 11, 2021.

The topics included discussing CCS projects and, in particular, CO_2 transportation, biogas plants, and others.

E.6 Interview with Jan Halin, Commercial manager at Den Harogh Gas logistics – January 12, 2021
Mr. Jan Halin provided valuable information about the costs and technicality of CO_2 transportation by trucks and much more details about the road logistics.

E.7 Interview with Jeroen Driessen, Global Sales Manager Biogas at Pentair – January 14-01-2021
Mr. Jeroen Driessen provided an enormous amount of information about UBG plants and CO_2 recovery and overall biogas and biomethane industry in general and the business at Pentair.

E.8 Interview with Jeroen Driessen, Global Sales Manager Biogas at Pentair – January 25, 2021

E.9 Interview with Dr.Marlinde Knoop, Scientific assistant at Knowledge Institute for Mobility Policy (Kennisinstituut voor Mobiliteitsbelied (KiM)– February 19, 021
Dr. Knoope provided a generous amount of information about the pipelines and their costs and other tips about the scale factor and cost inflation.

E.10 Interview with David Hynes, Sales Manager, Biogas and CO_2 Systems at Pentair -
The topics included in-depth discussion about the biogas industry and the overall costs of the carbon market, capture costs, electricity consumption, CAPEX, OPEX, and others.