CHALMERS
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Combined Heat and Power Plants Integrated with Carbon Capture

Process and System Level Potential

Master's thesis in Sustainable Energy Systems and Innovative and Sustainable Chemical Engineering

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Department of Space, Earth and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
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Master's thesis 2020

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Acronyms

CCS Carbon Capture and Storage

CHP Combined Heat and Power

DH District Heating

FGC Flue Gas Condensing

HOB Heat Only Boiler

MEA Mono Ethanol Amine

MSW Municipal Solid Waste

List of Symbols

α	Power to Heat Ratio
β	Specific heat reboiler duty
KPI_{el}	Key electricity production performance indicator of a DH network
η_{el}	Electrical cycle efficiency
η_{heat}	Heat energy cycle efficiency
η_{tot}	Total cycle efficiency
Q_{excess}	Excess heat produced from CHP in the DH system
F_k	Fraction of peak demand
FLH_p	Full load hours for a plant
$FLH_{p,tot}$	Summarised full load hours for all plants in a district heating system
KPI_{fuel}	Key fuel performance indicator of a DH network
$Q_{fuel,CCS}$	Total annual CHP fuel consumption with CCS integrated
$Q_{fuel,noCCS}$	Total annual CHP fuel consumption without CCS integrated
KPI_{heat}	Key heat delivery performance indicator of a DH network
$Q_{heat,CCS}$	Total annual CHP heat delivery with CCS integrated
$Q_{heat,noCCS}$	Total annual CHP heat delivery without CCS integrated
$m_{CO_2,p}$	Carbon captured from one plant
M_{CO_2}	Carbon captured over a year
m_{CO_2}	Mass flow of CO_2 in flue gases
q_{boiler}	Boiler energy output
q_{CCS}	CCS reboiler heat duty
q_{DH}	Heat output from steam cycle - used for district heating
$q_{DHmax,n}$	Maximum peak demand for DH network "n"
$Q_{fuel,p}$	Total plant fuel input over one year
q_{FGC}	Flue gas condensing heat output
q_{fuel}	Fuel energy input
Q_{heat}	Total annual heat delivery
$q_{th,tot}$	Total steam capacity in a steam network

$q_{T,n}$	Thermal heat flow through turbine "n" in a joint steam network
$q_{heat,tot}$	Heat output of all plants in a DH-network
$R_{C,D}$	Ratio between total plant CHP plant capacity and peak demand
$W_{el,CCS}$	Total annual CHP electricity generation with CCS integrated
W_{el}	Total plant electricity output over one
$W_{el,noCCS}$	Total annual CHP electricity generation without CCS integrated
w_{pump}	Pump electricity input
w_{T}	Turbine electricity output
$w_{T,n}$	Electricity output from turbine "n"

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Abstract

The world has expressed a strong desire to mitigate climate change during the past decades. In Sweden, the government has expressed the aims to achieve negative carbon emissions, Carbon Capture and Storage (CCS) is one of the key technologies in reaching this goal. This thesis determines the national potential for carbon capture in the Swedish waste and biomass fired Combined Heat and Power (CHP) plants. The effects on plant performance and the operation of connected district heating systems are evaluated.

The evaluation was performed by developing CHP plant process models of all 110 Swedish CHP plants based on plant data. Each model was retrofitted with post-combustion carbon capture units with a 90 % capture rate of plant carbon dioxide emissions. A district heating system dispatch model was created and incorporated with the process models. The operating profiles of each plant was estimated based on the heat demand within each district heating network. Four strategies for operating the CHP plants were evaluated, based on the fuel consumption, district heating delivery and electricity generation relative to the amount of carbon captured.

The results of the evaluation showed that the Swedish CHP plants alone have the potential, if equipped with CCS, of reaching Sweden's goal of 11 Mton negative emissions. The Power to Heat Ratio (α) (before implementation with CCS) is the most determining factor for the CHP process performance after CCS integration. The most determining factor for the district heating network performance is the ratio between plant heat generation capacity and the peak demand for district heating. Each operational strategy investigated, had advantages and disadvantages. The fuel consumption will increase with the implementation of CCS regardless of the operating strategy, although to different extents. Also, most CHP plants will not be able to maintain the present heat delivery if integrated with CCS. Each district heating system is, however, unique and should be investigated in further detail.

Keywords: CCS, CHP, district heating, biomass, waste.

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We would like to thank our amazing supervisor Johanna Beiron who has been incredibly supportive throughout the project. All our questions have been properly answered and she has fought hard to get all the diverse data and materials we have needed. Her thorough feedback has strengthened our report and it would not be half as good without her.

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Madeleine Ahlmén and Jesper Hellsberg, Gothenburg, May 2020

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1
Introduction

Currently a majority of the world's energy supply comes from fossil fuels [2]. A strong willingness and several climate targets to mitigate climate change has driven innovation and several carbon neutral, and even carbon negative power generation technologies now exist. Technologies to capture and store carbon dioxide (CO_2) emissions, Carbon Capture and Storage (CCS), are seen as a necessity to reach global climate targets [3]. These technologies often require a lot of energy. In Sweden, the government has published an investigation outlining how Sweden's net emissions can become negative by the Year 2045 [4]. It is assumed that the fossil share of the emissions can only be reduced by 85 % by 2045 from 1990's level of emissions. Therefore, the remaining 15 %, corresponding to 11 Mton CO_2, must come from negative emissions. To reach the goal of negative emissions, a part of the method presented includes implementing CCS on biogenic combustion (BECCS) within Swedish energy production and industry.

Combined Heat and Power (CHP) plants are a central part of Sweden's energy system as Sweden has a strong tradition of using district heating (DH). CHP plants produce both district heating and electricity. In 2018, 8.5% of Sweden's total electricity production and about 50% of Sweden's district heating came from CHP [5]. Sweden has a long history of district heating, the urbanisation and population increase in the forties led to large cities building centralised CHP to manage the increased heat and electricity demand. The demand for heat has increased over the last decades, leading to large district heating networks and many centralised heating units. Today 270 of Sweden's 290 municipalities have a district heating network [6].

In the beginning of the nineties, energy taxes on CO_2 emissions were introduced to keep the amount of fossil fuels down, most of Swedish CHP is therefore fuelled with bio fuels or municipal solid waste (MSW). Installing CCS on Swedish CHP could be a part of the answer to reaching the goal of negative emissions. Several studies investigate the potential of integrating CHP with CCS. Since the existing Swedish CHP capacity is large, retrofits and, thus, post-combustion types of CCS should be foremost considered. A post-combustion CCS testing plant has been installed on a part of a flue gas stream on a biomass CHP plant in Stockholm by the company Stockholm Exergi, showing potential for the technology [7]. A study by S. Öberg investigates the costs associated with adding post-combustion CCS to a MSW-fired CHP plant in Sweden [1]. In the study, the effect on heat production is investigated, however it is not set in the context of the district heating system. The district heating system will be affected by a reduced amount of heat production due to CCS, which can lead to increased use of other heat sources, sometimes fossil.

1.1 Aim

There are several types of CHP plants in Sweden, where multiple sizes, configurations and fuel types are used which affects their capability of supporting CCS. By organising the types of plants in different categories, the effects and potential of adding CCS to all of Sweden's CHP can be evaluated. Integrating CCS with CHP plants will reduce the process heat output of the plant. This thesis aims to determine the potential of implementing CCS on Swedish CHP and combine the knowledge of CCS process integration and energy systems, ultimately looking into the effect CCS implementation would have on the operation of district heating systems. The total potential of CCS on the aggregated CHP plants in Sweden will be evaluated and presented in terms of carbon captured per year. More specifically, this thesis aims to answer the following questions.

- How does implementation of CCS impact the heat output of different waste and biomass CHP plants?
- How will CCS integration on Swedish waste and biomass CHP plants impact the operation of district heating systems?
- What is the total carbon capture potential of implementing CCS on Swedish CHP plants?

1.2 Report overview

The outline of the report follows a bottom-up approach starting with a process perspective which is scaled up to district heating networks and, ultimately, a national level. Initially, a background chapter on CHP and CCS is included to cover essential knowledge for the thesis. Further on, an introduction to the data containing the plants in Sweden is presented, which serves to give an idea of different characteristics of importance among Sweden's CHP plants. The chapter on Sweden's CHP is followed by the method of the project, covering the different stages; where the process approach leads into the system approach. Next in turn are the results which cover the CCS integration as well as the four case studies, together with a discussion of the results presented. The report is concluded with a chapter covering the conclusions drawn from the project as well as a brief highlighting of further work that could be done.

2

Combined Heat and Power

A CHP plant is a combustion plant that, as the name declares, produces both heat and power. This technology is used to maximise the use of fuel, since high thermal efficiencies can be reached [8]. In practice, CHP plants deliver heat to both district heating and industry. However, this thesis focuses on plants that deliver heat to district heating networks. Although there are several ways to co-generate heat and power, this thesis focuses on methods involving steam turbines, since this is the most common method in Sweden. The following sections will present a more detailed technical and systemic description of steam cycle-based CHP.

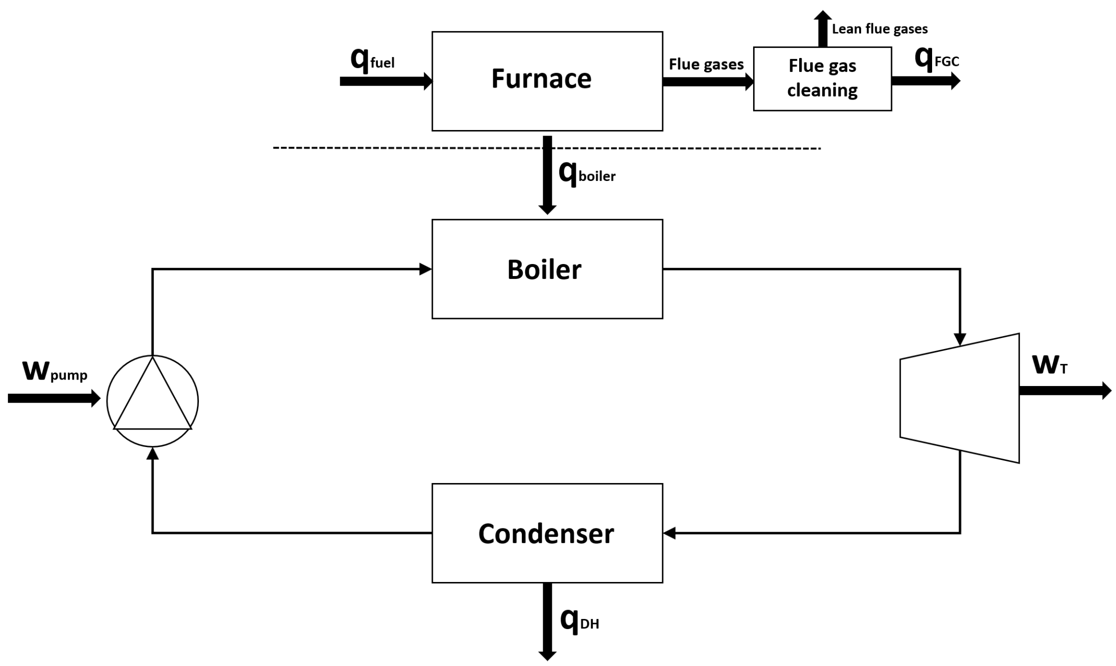


Figure 2.1: A simplified illustration of a basic steam cycle. The dashed line represents an optional system boundary. q_{fuel} is the heat added to the system from the fuel while q_{FGC} denotes the heat recovered from condensing the water in the flue gases. q_{boiler} denotes the heat added to the steam cycle from the boiler, whereas q_{DH} is the produced heat. w_{pump} and w_T are the pump work electricity and the produced electricity respectively.

2.1 System boundaries and efficiencies

A basic steam cycle process scheme is presented in Figure 2.1. Generally, when considering a steam cycle the system boundary is drawn at the dashed line in Figure 2.1, resulting in the inputs of the system being the boiler heat flow, q_{boiler} and the pump electricity, w_{pump}. The two outputs then become the turbine work, w_T and condenser heat flow, q_{DH}. The total efficiency can be calculated with Equation 2.1.

$$\eta_{tot} = \eta_{el} + \eta_{heat} = \frac{(w_T - w_{pump}) + q_{DH}}{q_{boiler}} \tag{2.1}$$

However, sometimes the system boundary is extended to also include the furnace and flue gases. The inputs then become the fuel input into the furnace, q_{fuel}, and the pump electricity. Typically, boilers have an efficiency of 80-88 %, thus since q_{fuel} in practice is not equal to q_{boiler}, and also due to the sometimes occurring flue gas condensing (FGC), the efficiencies differ depending on the choice of system boundary. The total efficiency of the cycle is for this case calculated by using Equation 2.2, where q_{FGC} denotes the heat recovered from condensing the flue gases.

$$\eta_{tot} = \frac{(w_T - w_{pump}) + q_{DH} + q_{FGC}}{q_{fuel}} \tag{2.2}$$

The measurement q_{boiler} can also be referred to as the thermal capacity of the plant which is usually used to state the size of the boiler. When considering the performance of a process cycle, another indicator of interest is the power to heat ratio, α, which is the ratio between the produced electric power and the production of useful heat. To calculate α, this project uses Equation 2.3.

$$\alpha = \frac{(w_T - w_{pump})}{q_{DH}} \tag{2.3}$$

In the pursuit of higher values for α, to increase the electricity production, several different configurations exist which are based on using extraction points from the turbine. The extracted steam is used for either feedwater preheating or as a two stage district heating exchanger [9]. These configurations will affect α and thus the electric efficiency. In addition to alternative configurations, there are however other ways to increase α, for example, increasing the temperature and pressure of the live steam.

2.2 CHP inputs

The main input for a CHP plant is the fuel, which is combusted in the furnace. Heat is exchanged from the furnace to the steam boiler, generating steam. Moreover, there are several different types of fuel to consider for CHP; waste, fossil based ones such as oil and coal as well as renewables including biomass and biogas. Naturally, they all differ when it comes to both physical and chemical properties, and some of them are more easily handled than others. Most commonly, direct combustion of biomass and waste is used in Sweden [5]. Fossil fuels are used mainly as reserves and are, due to the climate incentives in Sweden and the EU, often expensive to run [10].

In Sweden, biomass mostly comes in the form of wood chips and pellets, which due to their small sizes enables an even combustion [11]. A large amount of forestry residues are also available which further promotes the use of biomass when producing energy. Additionally, peat is included as biomass in this project, this due to the state of the current Swedish laws where peat is eligible for electric certificates. Biomass is often considered carbon neutral, which is why it has gained a lot of ground in Sweden's energy industry over the last three decades [6]. There are, however, also a few drawbacks with biomass as a fuel. There is an ongoing discussion on whether, and to what extent biomass can be seen as carbon neutral since the carbon binding rate of biomass is limited [12]. From a more technological perspective, some biomass contains high amounts of chlorine which sets limitations on the temperature in the furnace, since it gives rise to corrosion, thus fouling, on process equipment reducing its lifetime and heat exchanging performance [13].

Waste is often Municipal Solid Waste (MSW) and contains a heterogenous mix of materials, including some with fossil origin. It is estimated that 48 % of waste is from fossil sources [5]. Waste incineration can therefore only be considered partly CO_2 neutral at best, but it is an increasingly important way of managing waste flows in society. In Sweden, waste incineration is encouraged in forms of subsidies and taxes [14]. In other words, companies are paid to incinerate waste to generate energy. This, in contrast to biomass which is an expensive fuel, results in waste being an attractive fuel for CHP. However, due to its diverse content, waste often contains high amounts of ash and heavy metals, leading to high amounts of slag which has to be removed from the bed and flue gases [15].

Type of fuel will strongly impact the type of boiler that can be used as well as the maximum temperature that the steam can reach. To keep high enough flue gas temperatures and limit unwanted species in the flue gases, the fuel type will also influence the extent to which a plant can be operated at part load. The diversity of content in waste fuels will lead to larger temperature fluctuations in the boiler, especially at part load. To account for this, minimum load for waste plants are determined to be 70 % of maximum load. For biomass plants, the minimum load is set to be 30 % of maximum load.

2.3 CHP outputs

This section will consider the three plant outputs; heat, electricity and flue gases. Heat output will be related to the district heating system and how the plants are operated. Electricity and the electricity system is not a main focus of this project and will only be mentioned briefly. When it comes to flue gases, CCS will be introduced and elaborated on.

2.3.1 Heat and district heating

Heat is an important output from CHP, mostly it is used for district heating. Simply put, a district heating network consists of a centralised facility that generates hot water, to a temperature of between 70 and 90 °C which is distributed in pipe networks, to heat up buildings and produce hot tap water. When the heat is delivered, the water flows back to the heat production plant, usually with a temperature between 40 and 50 °C depending on outside air temperature. From here the cycle is then repeated [6]. Determining the supply temperature for a district heating network is generally based on a compromise between different factors; outside air temperature, heating demand and piping diameter among others. For lower outside temperatures, the demand for district heating increases. An illustration of how the district heating demand depends on the outside temperature is shown in Figure 2.2, where it can be seen that the relationship between heat demand and outside air temperature is linear. However, for temperatures above 15 °C, the district heating demand is constant. The constant heat demand is due to the reduced need for household heating and the heat demand will only be for hot tap water.

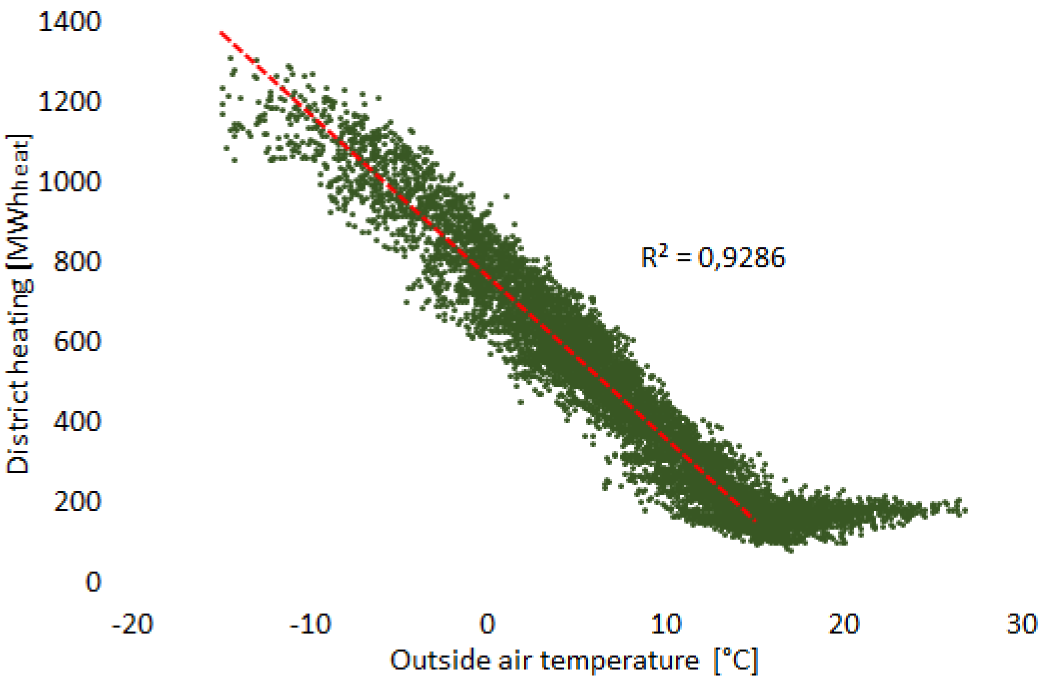


Figure 2.2: District heating demand versus outside air temperature in Gothenburg 2012. The red line represents a linear regression for temperatures below 15 °C.

To further demonstrate how the hourly district heating demand might vary throughout a typical year, the district heating demand for Gothenburg 2012 plotted against time is shown in Figure 2.3. The demand is lower, and remains rather constant during the summer due to the outside temperature being greater than 15 °C. During the night, demand for house heating is generally higher due to lower outside temperature, and the tap water usage is normally higher during the day.

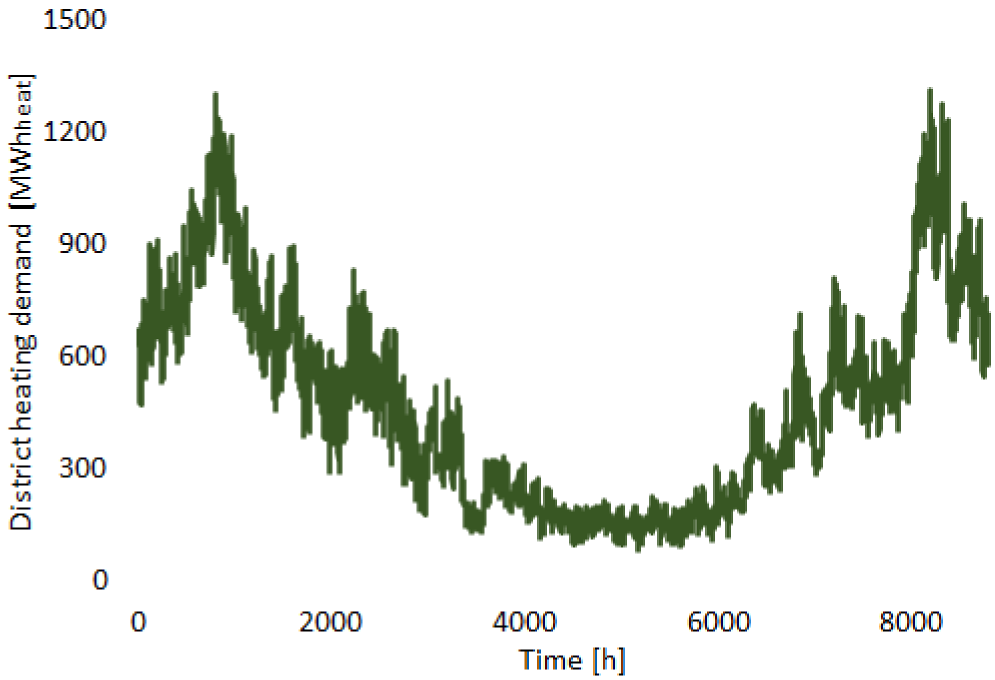


Figure 2.3: Hourly district heating demand in Gothenburg throughout 2012.

In Sweden, district heating is mainly produced by CHP plants, Heat Only Boilers (HOBs) and with waste heat. However, some networks also use heat pumps, electrical boilers, geothermal and solar energy [16]. These technologies have different roles in fulfilling the heat demand, some serve as the base load and some are mainly used as peak loads. A conceptual illustration of how the different production categories are used is shown in Figure 2.4. It is often the technology with the lowest operating cost that will be run as a base load whereas the most expensive, but also most flexible technology will be used to fill the peak demand. Base load is often MSW or biomass CHP, while peak load can be covered by oil or natural gas fuelled HOBs or CHP plants. The operating cost for combustion technologies is usually fairly constant over a longer time period, whereas technologies based on electricity inputs will be more vulnerable to the volatility of the electricity market.

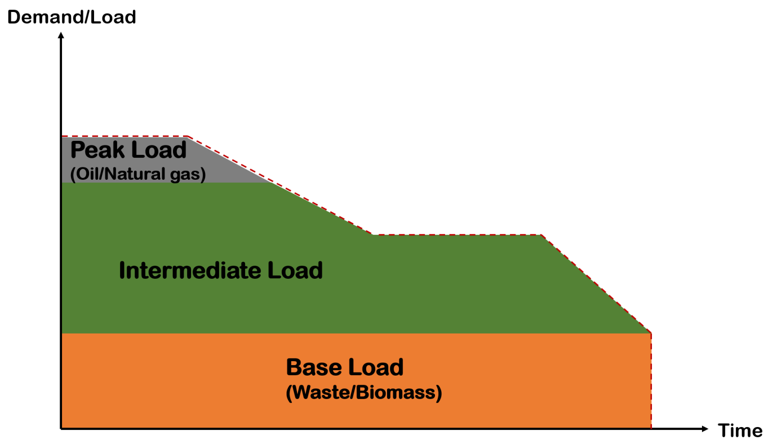


Figure 2.4: Illustration of district heating demand and supply divided into base, intermediate and peak load blocks.

2.3.2 Electricity production and the electricity market

The second main output from CHP is electricity, which is generated in the turbine. From there, the electricity is transmitted to the power grid. The Swedish electricity comes from several sources, in which CHP only accounted for 5.6 % of the total production in 2017 [17]. The Swedish electricity system uses nuclear power and CHP as its base load, however other renewable sources of electricity, such as hydro power and wind power makes electricity readily available at a low cost many hours of the year.

Generally, electricity prices vary according to the balance between supply and demand, i.e. when the demand is high compared to supply the prices rise and vice versa. The highest electricity demand is often found in the winter, when demand for district heating is also high. If the demand for district heating is higher than the production capacity, some district heating networks utilise heat pumps or electric boilers to exchange electricity for heat. On the other way around, a CHP plant sacrifices heat to produce electricity. Subsequently, the two energy markets co-vary and are, to some extent, coupled.

2.3.3 Flue gases and CCS

The flue gases from CHP contains a variety of different pollutants and greenhouse gases (GHG) as well as water vapour. Generally, an air ratio higher than 1 is desired in order to facilitate full combustion and reduce unwanted substances in the emissions. Today, due to strict pollution regulations, most CHP plants are also equipped with flue gas cleaning facilities that rids the flue gases of hazardous substances such as nitrous oxides, fly ash and dioxins. Wet flue gas cleaning is a technology that is often used to remove acidic gases by absorbing them in either pure water, or an alkaline solution. The wet flue gas cleaning also opens up for the possibility to condense the formed water vapour from the combustion gases which provides additional heat production [18].

Regulations regarding CO_2 emissions are currently becoming stricter, leading to increased economical interest in reducing carbon emissions. One way to achieve this is with removal of CO_2 emissions from the flue gases via CCS. If carbon capture units are implemented at plants fuelled by biomass, negative emissions could be achieved via so-called BECCS, which is short for Bio Energy Carbon Capture and Storage. Mainly, there are three configurations of CCS; post-, pre- and oxy-fuel combustion, which each have their advantages and disadvantages [1]. Since this report focuses on potential of CCS on already existing processes, an alternative which can easily be applied to a retrofitting perspective is favourable. Due to this, only the post combustion configuration will be considered.

Post combustion CCS focuses on separating carbon dioxide from the exhaust gases from combustion. The levels of CO_2 are higher than in regular air, which facilitates the separation and leads to a higher amount of captured CO_2. Typically, a 90 % capture rate is assumed for this type of CCS. A process scheme of a typical Rich Stream Split (RSS) CCS facility is presented in Figure 2.5. The capturing is most commonly achieved by absorbing the CO_2 in an aqueous solution, typically buffered with monoethanol amine (MEA). The MEA is then, in a stripper column, exposed to heat, which separates the CO_2 from the MEA, and the CO_2 can be transported to and placed in storage reservoirs [19, 1]. Since a regeneration of the absorbents is desired, high amounts of heat is required for the process reboiler as well as electricity for pumping and fanning of the material flows and compression of the captured CO_2 [19].

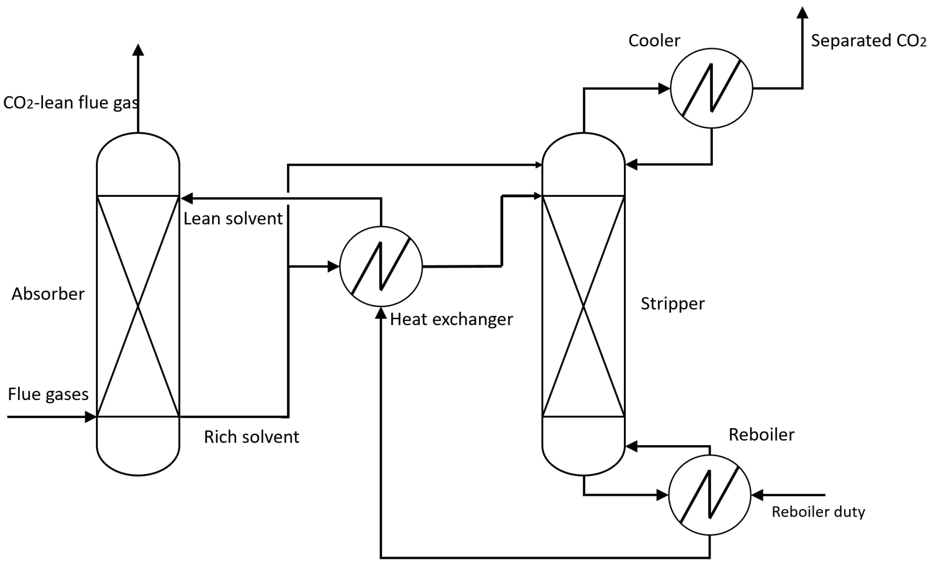


Figure 2.5: Fundamental scheme of a post-combustion CCS process equipped with a Rich Stream Split (RSS), which is typically used for enhanced heat efficiency [1].

In the study conducted by S. Öberg [1], it was found that a reboiler duty between 2.8 and 4.0 MJ was required per kg CO_2 captured. Additionally, MEA must not be heated to above 120 °C in order to eliminate the risk of the absorbent decomposing. This can easily be achieved by using saturated steam at 6 bar for heating [1]. The energy demands of the process result in high operational costs which are topped off with the capital costs of the equipment. Together with a lack of regulations for CO_2 emissions, these high costs have earlier been the main reasons why CCS is not yet commercialised [1]. In another study conducted by Biermann et al. [20] the specific electricity consumption for an MEA absorption CCS unit was found to be about 3.8 MJ/kg CO_2 for a capture rate of 90 %. This includes compression of the CO_2 to 100 bar for transportation [20].

Moreover, due to variations in CHP load, the flue gas flows will also vary. For a CCS unit designed for a certain CHP load, operation at off-design conditions will result in decreased performance of the CCS. A way of circumventing this is to install a partial CCS unit which only processes a portion of the flue gases. This enables cheaper capital and operational costs while still meeting initial restrictions regarding CO_2 emissions [1]. Focus in this project will however be on full carbon capture, where 90 % of the CO_2 in the flue gases is captured.

3
Swedish CHP plants

The data on Swedish CHP plants used in this project, consists of qualitative and quantitative information about 110 Swedish CHP plants. The CHP plants are spread over 78 district heating networks in Sweden where most of the large towns are covered. CHP plants covered use biomass or waste as a fuel and their main purpose is to provide district heating.

Two fundamental categories are used to describe the data; location and fuel. The fuel is divided between biomass and waste, where biomass includes several types of biomass and waste is limited to MSW. The location of the plants is divided between north and south, where the geographical division is to handle the large climate difference between different parts of Sweden which leads to different demands for district heating. The definition between north and south is based on the European POwer Dispatch (EPOD) region that the plant is located within. There are four EPOD regions in Sweden, SE1 and SE2 are regions in the north and SE3 and SE4 are more to the south. From these categories, some of the trends, but also differences found in Swedish CHP are pointed out.

3.1 Alternative steam cycle configurations

Figure 2.1 shows the basic steam cycle configuration, however very few plants will have this exact configuration. This section will present a few of the ways in which Swedish CHP plants differ from the basic steam cycle configuration.

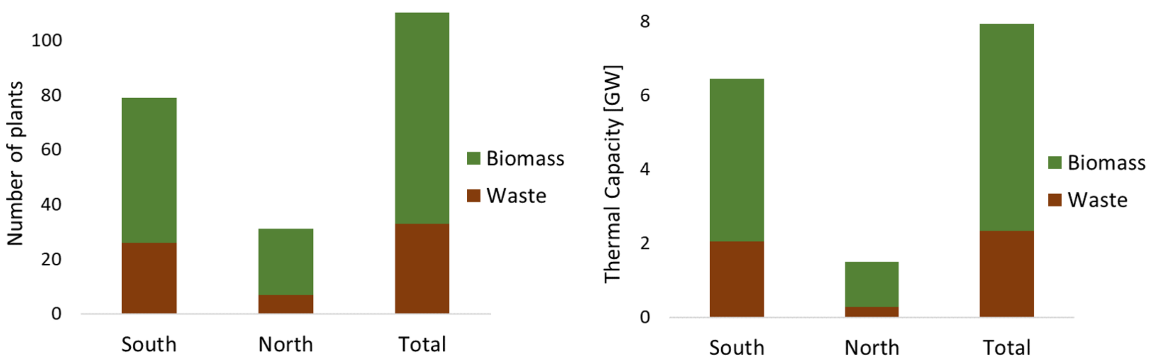
A large joint steam network is the case in a few of the CHP plants covered by the data. There is no direct purpose of having steam in a joint network and such systems are often a consequence of several retrofits. An example of this is Högdalenverket, located just outside of Stockholm. The steam network consists of steam from 5 waste boilers that enters a steam network with two turbines.

Some CHP plants are designed to have as high α values as possible. This can be achieved by implementing turbine extraction steps. There are two ways in which this is commonly done, either by adding feedwater preheating or adding a second step in the heating of the DH feedwater. The purpose of adding a second DH step is to allow for a lower temperature, and thus pressure, out from the turbine, increasing the electricity output. Feedwater preheating reduces the fuel demand, giving an increased electric efficiency.

There are several plants where electricity production is not prioritised due to the steam being used for other purposes. Steam is needed in many industrial processes and can be used within the plant, for example in the flue gas cleaning process or for air preheating. It is also common to sell steam to proximate industries. In some cases, often with smaller plants, an old turbine is retrofitted to an existing boiler. The turbine is not always designed for the specified steam flow, which generates a lower α-value.

3.2 Trends in Swedish CHP

The CHP plants in Sweden are spread out geographically, with a majority of them located in the southern parts. Figure 3.1a shows the total number of plants installed in each region, whereas Figure 3.1b shows the total installed thermal capacity in northern and southern Sweden. Waste and biomass are both distinguished in the two figures. The number of plants within each category gives an idea of the total capacity in each region and for each fuel. As can be seen in Figure 3.1, a majority of the plants are located in the south, most plants also use biomass as the main fuel. Comparing the height of the bar for the north in number of plants and installed capacity, it can be seen that the plants are on average smaller in the north than in the south. The average thermal capacity of a plant in the north is about 48 MW compared to the average thermal capacity in the south of 82 MW.



(a) Number of plants (b) Total steam capacity

Figure 3.1: Number of plants and the total thermal capacity installed in Swedish CHP, divided into fuel categories and location.

The spread of α compared to thermal capacities can be seen in Figure 3.2. Fuel used is included to show trends for the different fuel types. As Figure 3.2 shows, plants with lower thermal capacity tend to have lower α. The α varies between 0.1-0.7 and the thermal capacity varies between 10-540 MW. However, only a few plants are larger than 200 MW. Waste plants have slightly lower α than biomass plants and the largest waste plant is only 170 MW.

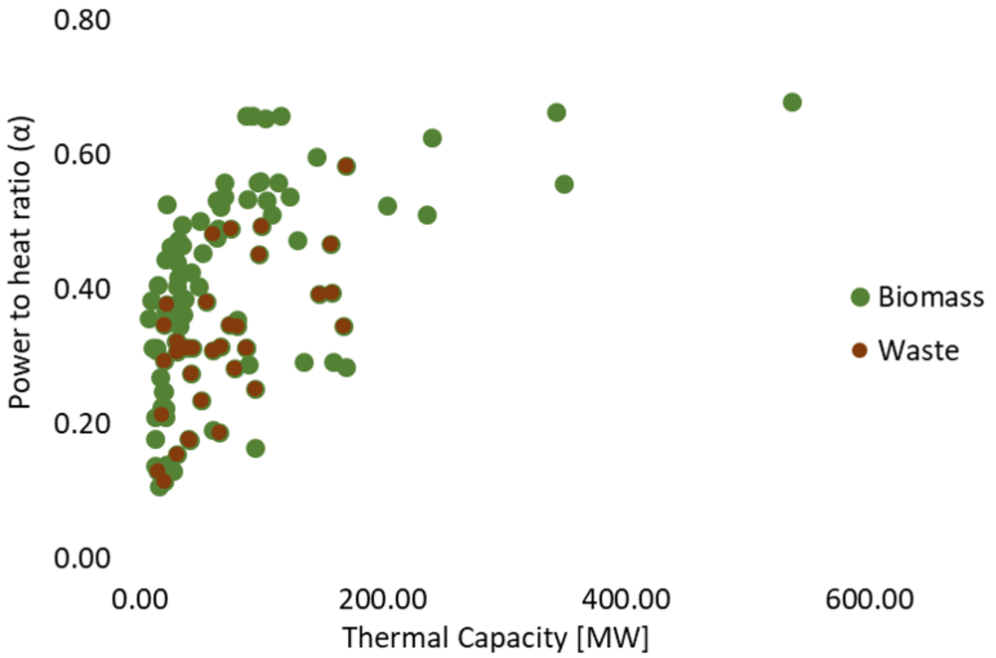


Figure 3.2: Thermal capacity compared to the plants α for the CHP plants included in this study.

Of the 78 DH networks that include CHP plants, most of the networks only have one CHP plant. However a third of all DH networks have more than one plant. Figure 3.3 shows how the CHP plants are divided between DH networks. The highest number of plants in one DH network can be found in Stockholm city's DH network, where a total of four CHP plants are included.

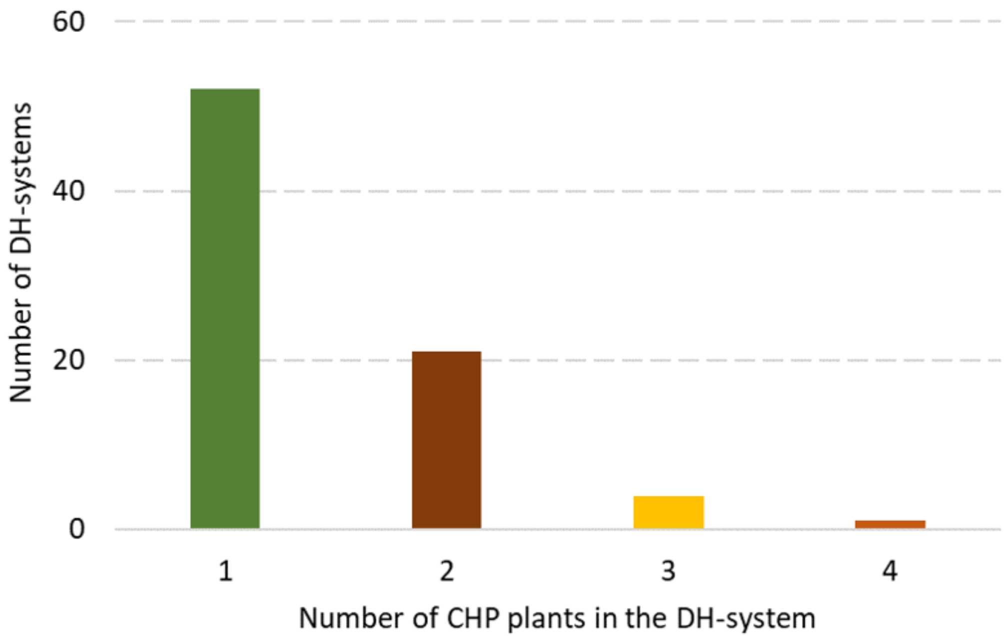


Figure 3.3: CHP plants divided into DH networks. Number of CHP plants in the DH network is compared to the number of DH networks with that number of CHP plants.

4
Method

Figure 4.1 shows the structure of the method. The project method is divided into two approaches, the process approach and the system approach. In the process approach, the information about Swedish CHP plants, presented in the previous chapter, was converted to a database, which can be found in Appendix A.1. CHP process models were developed, based on the data on Swedish CHP plants. The process models were then retrofitted with CCS, and an additional operational Heat Only Boiler (HOB) mode, was introduced. In the system approach, the CCS models were applied to each individual DH system in order to evaluate the performance of the DH systems if CCS would be implemented. Each DH system had its performance investigated for four cases of operational strategies after which each case's performance and national carbon capture potential was evaluated. Inputs and outputs from the other stages are defined and will be explained further in this chapter.

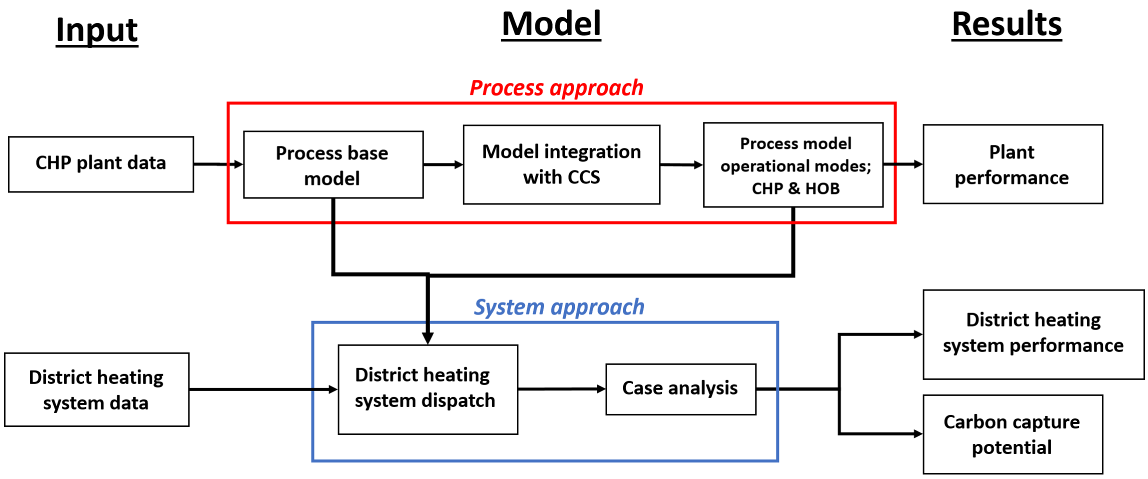


Figure 4.1: The project workflow.

4.1 Process model

This section explains the development of the process models. The categorisation method used to make sure that the model matched the data as well as how CCS was integrated with these models is explained. A description of the main model specifications is also included in this section.

4.1.1 Plant categorisation

The alternative steam cycle configurations that exist in Swedish CHP were taken into consideration. The data on Swedish CHP plants was processed to support these alternative configurations. As explained in Section 3.1, there are cases where the steam is in a large joint network, connected to several boilers and turbines. To make it possible to model joint networks, each turbine was treated as a separate CHP plant, according to the following allocation method:

- Total steam capacity was determined in MW for the entire network, $q_{th,tot}$
- Electrical output from each turbine was determined, $w_{T,n}$
- Each turbine was seen as a separate plant and the steam was allocated based on equation 4.1, where, 'n' denotes the n:th turbine, while 'N' is the total number of turbines in the steam network.

$$q_{T,n} = \frac{w_{T,n}}{\sum_{k=1}^{N} w_{T,k}} \tag{4.1}$$

Other alternative steam cycle configurations were also considered when formulating the process models. CHP processes that have alternative configurations that include either turbine extraction steps or a turbine by-pass, have been modelled by categorising the plants into six different design categories. Turbine extraction steps and a turbine by-pass will change the plants power to heat ratio, α. The six designs were produced by adding turbine extraction steps and a turbine by-pass to the basic steam cycle. The basic steam cycle can be seen in Section 2. Figure 4.2 shows how the six designs were produced. The power to heat ratio of the plant increases with a higher number of extractions. The By-pass Design matches the lowest α values.

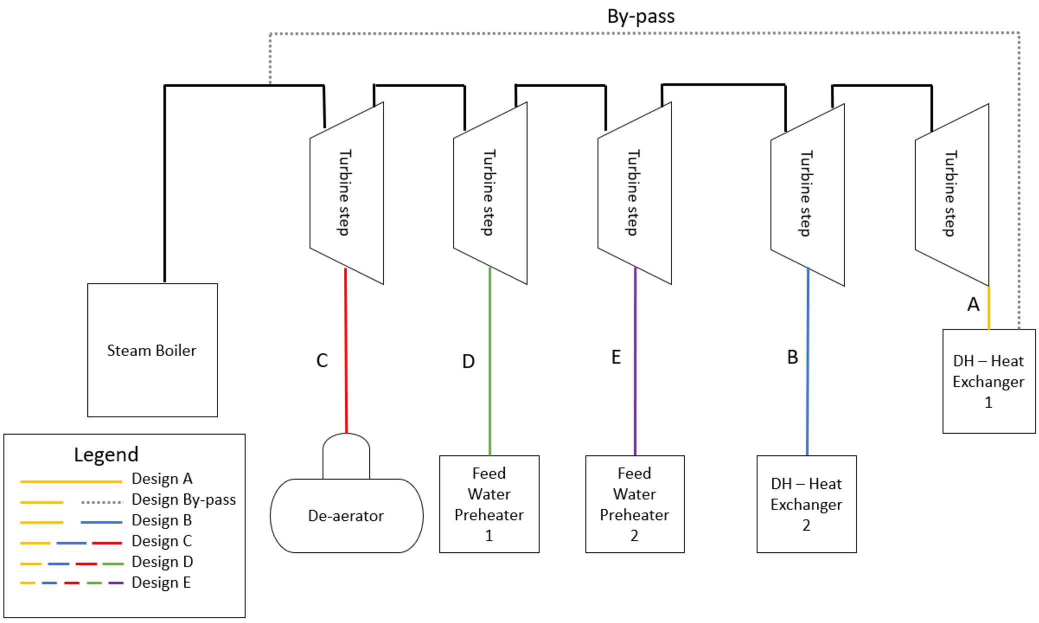


Figure 4.2: The CHP plant designs used to describe the categories of CHP plants and to create the process models. The designs, (A-E + bypass), depend on the number of extractions, where the number of extractions increases from A to E.

In Design A, the steam passes all the way through the turbine before it condenses in the first DH exchanger. In the other designs, some steam is extracted at higher pressures to increase the plant α. The six designs, A-E and By-pass, were modelled in EBSILON®Professional. All process designs for the base model can be seen in Appendix B.1 and a further description of the specifications used to produce the models can be found in Section 4.1.3.

The process model uses the thermal capacities and live steam conditions from the database as input variables. Following the procedure explained in Figure 4.3, the outputs from the model for each plant matches the plant's outputs found in the database. Each CHP plant was assigned one of the six designs.

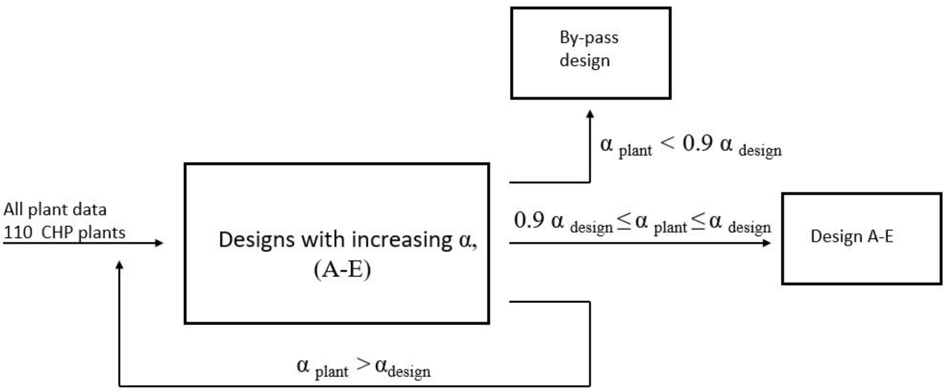


Figure 4.3: Method used to allocate each plant to a specific design.

The allocation method shown in Figure 4.3, will allocate each CHP plant to one of the six designs. Each plant was first simulated with Design A, if the simulated α matched the α in the database, it was placed in Design category A. If the simulated α in Design A was lower than the value from the database, it was simulated with Design B and so forth, until a design category matched the α in the database. For cases where Design A generated an α value that was more than 10 % higher than the expected output, the plant was placed in the By-pass Design category. The by-pass ratio was assigned to generate a power to heat ratio similar to its expected value.

4.1.2 CCS integration

The process model, made up of all the Swedish CHP plants divided into six designs, was used as a base to integrate the CHP processes with CCS. CCS was integrated with the CHP plants with two operational modes. The two modes of steam cycle operation with CCS are presented in Table 4.1. The CHP-mode and HOB-mode, requires the same fuel input, but the outputs differ. In HOB mode, the turbine is entirely by-passed, thus, the electricity production is discarded to generate a higher heat production. For both modes, steam at 6 bar powers the CCS process. However, since the turbine is not in operation in HOB mode, the steam by-pass is throttled to 6 bar instead of being extracted at 6 bar.

Table 4.1: Operating modes and method for CHP integrated with CCS.

Operational Mode	Outputs	Operation
CHP-mode	Electricity, heat and carbon capture	Steam for CCS is extracted from the turbine at 6 bar
HOB-mode	Heat and carbon capture	Steam for CCS is taken directly from live steam and throttled to reach 6 bar

The CCS integrated process model designs were also modelled in Ebsilon, and the final CCS designs can be seen in Appendix B.2. When operating with CCS in CHP-mode, the process designs A-E and By-pass, were used. The CCS reboiler was modelled as a heat consumer, using steam extracted from the turbine at 6 bar. In HOB-mode one design covers all plants in the database. Further Ebsilon specifications used in the models are presented in Section 4.1.3. The specific CCS reboiler duty was assumed to be constant, hence, a reboiler duty proportional to the amount of captured mass of CO_2 could be assumed. The assumed capture rate was 90 % and the amount of CO_2 captured was therefore 90 % of the total CO_2 content in the flue gases. Equation 4.2 shows how the CCS reboiler duty, q_{CCS} was calculated.

$$q_{CCS} = 0.9 * m_{CO_2} * \beta \tag{4.2}$$

In equation 4.2, m_{CO_2} represents the mass flow rate of CO_2 in the flue gases and β is specific reboiler duty for CO_2 separation in MJ/kg CO_2 which ranges from about 2.8 to 4.0 for a 90 % capture rate [1]. Since β depends on flue gas CO_2 concentration which in turn depends on several other factors, it was evaluated at the middle of the interval, i.e. 3.4 MJ/kg CO_2, but with a sensitivity analysis showing how plant efficiency is affected by the specific reboiler duty.

In CHP-mode, Assbergsverket CHP, Hofors Energi CHP and Siljan Timber Mora could not reach a 90 % capture rate with the steam that passed through the turbine due to their low values of α and thereby, capture rates of 82.5 %, 52.5 % and 82.5 % were assumed, respectively. The decreased capture rate was achieved by partial CCS, keeping the specific reboiler duty unchanged. CHP-mode and HOB-mode were evaluated based on the change in maximum heat output from the plants integrated with CCS compared to CHP-mode without CCS.

4.1.3 Ebsilon specifications

This section will explain how the thermodynamic cycles of the designs explained in the previous section were modelled in Ebsilon. To make the models generic and applicable to as many plants as possible, a basic thermodynamic cycle served as the base of all models. A standard pump, boiler, furnace and turbine was used. The CCS reboiler and DH network were both modelled as heat consumers, since heat consumers can remove the required amount of energy from the system. The heat consumer acting as the CCS reboiler is implemented as a retrofit to the process models described in Figure 4.2 with an inlet and outlet of steam at 6 and 3 bar, respectively. When simulating the amount of district heating available from the process, the delivered heat was equal to the heat removed by the DH heat consumer. No heat losses due to water transport were therefore considered and the heat delivery is, in reality, slightly lower. DH feedwater and return temperatures of 90 °C and 40 °C, respectively, were used to compensate for this. The feedwater preheating as well as the DH feedwater heating was achieved by Ebsilon's heat exchanger with the default settings.

Modelling of the inlet and outlet pressures of the turbine steps was done differently. The pressure drops over the turbine steps were assumed to be functions of the live steam pressure, P_l, which are presented in Table 4.2. Note that depending on the process model design, the number of extractions was different, as can be seen in Figure 4.2.

Table 4.2: Functions for turbine step outlet pressures.

Live steam pressure [bar]	First extraction	Second extraction	Third extraction	Fourth extraction
<80	$0.33 \times P_l$	$0.125 \times P_l$	Set by controller	Set by controller
>80	$0.33 \times P_l$	$0.07 \times P_l$	Set by controller	Set by controller

To assign pressures for the last two turbine steps, controllers were used with the criteria to assign extraction pressure that supplied sufficient heat for the DH to reach its target temperature. Further, to model the CCS, an extra turbine step with an extraction at 6 bar was inserted. To model the fuel input into the furnace, the compositions presented in Table 4.3 were used for biomass and waste. The biomass was assumed to be dry wood residues, thus not containing any moisture. An air ratio of 1.4 was used to account for the assumption of a full combustion taking place in the furnace.

Table 4.3: Used fuel composition of biomass and waste

Fuel Type	C	H	O	N	S	Cl	Ash	Water	Source
Biomass	49.7	6	41	1.7	0	0.1	1.5	0	[21]
Waste	29.8	4.2	15.4	0.6	0.2	0.6	13.2	36	[1]

4.2 DH system model

This section will present how the DH systems are affected by CCS integration with the CHP plants in Sweden. The outputs, determined in the previous section were used as input variables for plant operations in the DH system. DH demand profiles were produced for all DH networks in Sweden. CHP operating patterns were produced, with the objective to cover as much of the DH demand as possible. CCS was implemented on the plants to operate according to four different cases.

4.2.1 Demand profiles

Heat demand profiles for the DH networks over a year were generated. For the plants categorised as south, the demand profile has been approximated based on data for the predicted demand profile of Västerås DH network for 2021. The data includes the predicted demand, in MWh, for each hour of year 2021. The demand profile used can be seen in Figure 4.4.

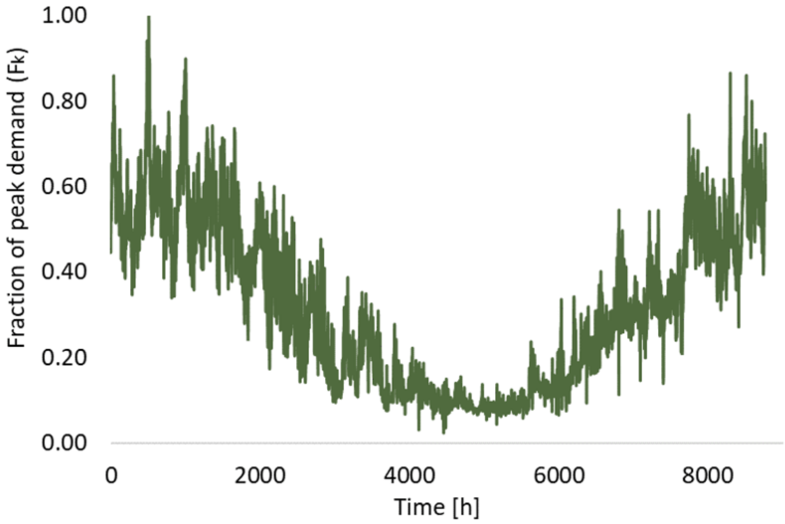


Figure 4.4: DH demand profile used for the south of Sweden, based on predicted heating demand for Västerås 2021. The demand has been scaled to show the fraction of the peak demand in the system (F_k).

The plants categorised as north have a heat demand profile determined by the linear relationship between DH demand and the air temperature profile. The relationship between temperature and DH demand shows a strong linear correlation for temperatures below 15 °C, as can be seen in Figure 2.2. Temperatures above 15 °C therefore had a constant demand of 9 % of maximum heat demand. Temperature data was recovered from the Swedish meteorological institute (SMHI) where the Storuman weather station was used to represent the temperature profile of the north. Storuman is located in the central-north parts of Sweden. The resulting DH demand profile for northern Sweden, presented in Figure 4.5, was produced.

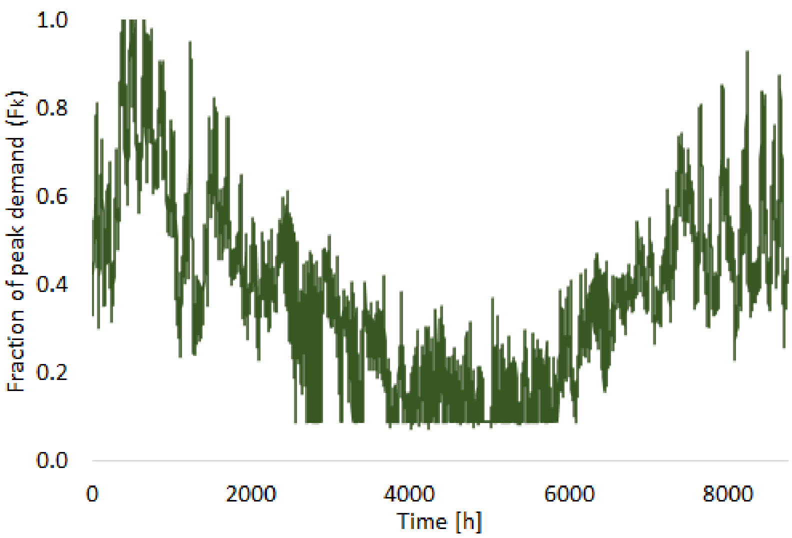


Figure 4.5: DH demand profile used for the north of Sweden, based on the temperature profile for Storuman. The demand has been scaled to show the fraction of the peak demand in the system (F_k).

Equation 4.3 was used for both north and south to determine the hourly DH demand in each DH network, based on the peak demand ($q_{DHmax,n}$). Equation 4.3 shows how the peak demand for any network, n, was determined using the hourly fractions of peak demand (F_k), from the two scaled demand profiles. $Q_{DHtot,n}$ is the yearly demand in MWh for the DH network n, this was found at *Energiföretagen* for the DH networks involved in this project [22]. Once the $Q_{DHmax,n}$ was found the heat demand for each hour was calculated by multiplying the $q_{DHmax,n}$ with the F_k for each hour.

$$q_{DHmax,n} = \frac{Q_{DHtot,n}}{\sum_{k=1}^{8760} F_k} \tag{4.3}$$

4.2.2 Plant dispatch order and operating constraints

The target of the CHP plants is to satisfy the heat demand, which is the determining factor for the operation of the plants. A CHP plant dispatch order was determined for networks with more than one CHP plant. The operating patterns for the CHP plants in the networks was determined by introducing operating constraints based on limitations and practicalities often considered when operating CHP plants in DH networks. The constraints and the dispatch order are presented in Table 4.4. As shown in Table 4.4, waste plants will always be run prior to biomass plants due to operational cost. The base load is always operated, while the other plants, were only operated if there is a demand left unsatisfied when plants with a higher priority were running. The minimum load of waste plants was set to 70 % and the minimum load for biomass plants was set to 30 %.

Table 4.4: Order in which the plants are run and constraints set within each plant.

Plant dispatch order	Operating pattern	Priority order	Minimum load (%)
Base load	Operated at all times	1. Largest waste plant	70
Second plant	Operated if needed for 10 consecutive days	2. Smallest waste plant	70
Third plant	Operated if needed for 10 consecutive days	3. Largest biomass plant	30
Fourth plant	Operated if needed for 10 consecutive days	4. Smallest biomass plant	30

The plants were operated at part load to follow the demand curve, however, if the demand is larger than a plants production capacity, it was run at full load. If the demand required a part load lower than the minimum part load for a plant, the plant was either run at minimum load or shut down. A constraint implemented on all plants, except the base load, was that the plant was only started if it was needed to fill the demand for at least ten consecutive days, otherwise it remained non-operating. The size of the plant was the second factor, after fuel used, that was considered when determining the priority order. Other factors such as cost of fuel used and age of plant could impact the dispatch order or operating constraints, but are not considered in this study.

To categorise the DH networks, a ratio of the CHP capacity compared to the peak demand was determined for each DH network. This ratio is henceforth $R_{C,D}$. The CHP capacity was defined as the maximum heat output of all plants in the DH network added together. This ratio was calculated for all plants according to Equation 4.4.

$$R_{C,D} = \frac{\sum q_{DH,p}}{q_{DHmax,n}} \tag{4.4}$$

$q_{DH,p}$ is the maximum heat output from the plant p in the network in question and $q_{DHmax,n}$ is the peak demand in that network. The plants maximum heat output, $q_{DH,p}$, was for without CCS in the system.

4.2.3 Operational cases for DH systems with CCS

The outputs generated from the CCS models were integrated with the DH system for four different cases, which are shown in Table 4.5. For the first two cases, the CCS integrated process outputs were used for all plants and at all times, but in the two different operational modes. The first case used CHP-mode and the second case used HOB-mode. The third case operated in CHP-mode however, the plants were only operated with CCS during the summer. Summer season is defined as May the 13th until September the 29th in the south and June the 5th to August the 25th in the north, based on data from SMHI. For the final case, the process was also operated in CHP-mode, however CCS was only installed on the first plant in the dispatch order, the base load.

Table 4.5: The four cases investigated for CCS system integration.

Case	Process operating mode	CCS operating time	CCS operating plants
1. CHP full	CHP-mode	All operational hours of the year	All plants in the DH network
2. HOB full	HOB-mode	All operational hours of the year	All plants in the DH network
3. CHP summer	CHP-mode	Only during the summer	All plants in the DH network
4. CHP base load	CHP-mode	All operational hours of the year	Only first plant in the dispatch order

For each case, the plant usage, seen as the full load hours for each plant over a year has been determined. Equations 4.5-4.7 shows how the fuel consumption ($Q_{fuel,p}$), electricity production (W_{el}), and CCS (M_{CO_2}) was calculated for a year. Together with the outputs determined from the process modelling, the number of full load hours for each plant, was used to calculate the total fuel consumption in GWh, electricity output in GWh and CCS in ktonCO$_2$ over a year. q$_{th,p}$ is the thermal capacity of a plant in MW, w_T is the maximum electric output from a plant in MW and $m_{CO_2,p}$ is the amount of carbon captured from a plant at full load with a 90 % capture rate, in kgCO$_2$/s. For the fuel consumption, a boiler efficiency (η_b) of 0.84 was used and full load hours for a plant is referred to as FLH$_p$.

$$Q_{fuel,p} = \frac{FLH_p \cdot q_{th,p} \cdot 10^{-6}}{\eta_b} \tag{4.5}$$

$$W_{el} = FLH_p \cdot w_T \cdot 10^{-6} \tag{4.6}$$

$$M_{CO_2} = FLH_p \cdot m_{CO_2,p} \cdot 3.6 \cdot 10^{-3} \tag{4.7}$$

When it comes to heat output, it was more important to determine the actual heat delivered, not only heat produced. The heat delivered is defined as the heat that is used to fill DH demand (in GWh) and therefore no excess heat was accounted for. This measurement will therefore require the operating profile for the heat to determine when heat was not needed to fill the demand. The excess heat (Q_{excess}) was therefore defined as the difference in heat produced and demand, i.e. for when the demand subtracted from the heat production for a given hour is greater than zero. Heat delivery was therefore calculated according to Equation 5.1, where $q_{heat,tot}$ is the sum of the maximum heat output in MW for all CHP plants in a DH system.

$$Q_{heat} = (FLH_{p,tot} * q_{heat,tot}) - Q_{excess} \tag{4.8}$$

4.2.4 Key performance indicators

All cases used a reference case as comparison, the reference case used plant inputs from the process model without CCS, and assumes the same dispatch order and constraints as presented in Table 4.4. Three key performance indicators (KPI) were composed, with the main purpose of facilitating a comparison of the four cases. The KPI's were calculated with the amount of carbon captured as their functional unit, and are explained through the following equations:

- KPI_{fuel} gives the change in the amount of fuel needed for CHP in the DH system with CCS compared to without CCS installed on the CHP. KPI$_{fuel}$ is calculated according to Equation 4.9. For DH networks with several plants, the sum for all plants in the system was used.

$$KPI_{fuel} = \frac{Q_{fuel,CCS} - Q_{fuel,noCCS}}{M_{CO_2,capture}} \tag{4.9}$$

- KPI_{el} gives the change in the electricity produced by CHP in the DH system with CCS compared to without CCS installed on the CHP. KPI$_{el}$ is calculated according to Equation 4.10. For DH networks with several plants, the sum for all plants in the system was used.

$$KPI_{el} = \frac{W_{el,CCS} - W_{el,noCCS}}{M_{CO_2,capture}} \tag{4.10}$$

- KPI_{heat} gives the change in the amount of heat delivered with CCS compared to without CCS. KPI$_{heat}$ is calculated according to Equation 4.11.

$$KPI_{heat} = \frac{Q_{heat,CCS} - Q_{heat,noCCS}}{M_{CO_2,capture}} \tag{4.11}$$

5

Results and discussion

The results from the CCS modelling are presented as a comparison between the CHP and HOB-mode. Focus is on how heat output is affected by the integration with CCS. For the case studies, the system level results are presented for the four cases individually after which a comparison is made. The individual results focus on the reasons behind certain trends found within each case. The comparison highlights the key performance indicators.

5.1 Impact on CHP heat output with CCS

The effect CCS integration has on heat output when operated in CHP-mode can be seen in Figure 5.1, where change in maximum heat output for each plant is displayed. Operating in CHP-mode shows that the heat production with CCS compared to without CCS will decrease with an increasing power to heat ratio, α. Plants with low α can maintain up to 80 % of the maximum heat production. The reason the heat production for plants with large α is more affected by CCS integration than plants with low α is due to the 6 bar extraction point. A high α is often related to higher steam pressures and before reaching the 6 bar extraction point, more electricity will have been produced. The maximum heat output will therefore be proportionally more reduced than reduction in maximum electricity output. The plants with low α will therefore have a comparably larger reduction in electricity production with CCS. Two of the outliers, with the highest heat production are due to the lower capture rates used in the corresponding plants.

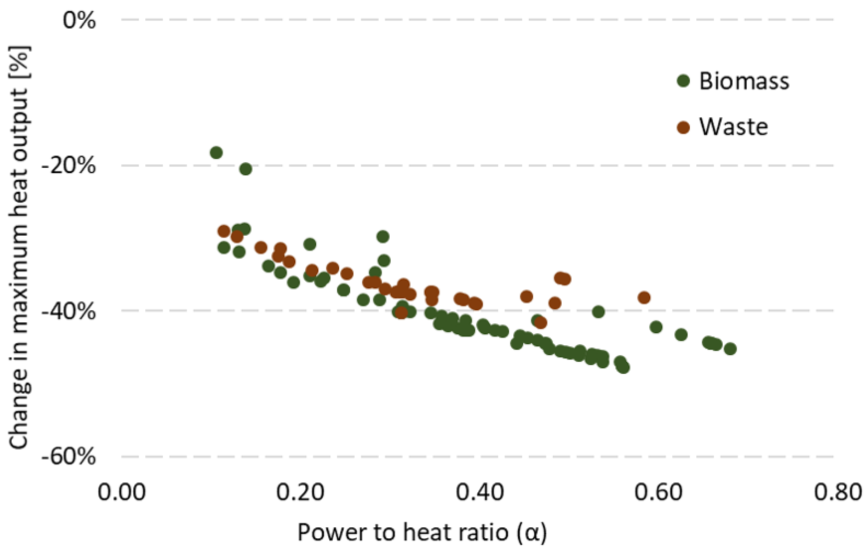


Figure 5.1: Change in maximum heat output of CHP plants integrated with CCS, when operated in CHP-mode. The α values are for the plants without CCS integrated.

When operating in HOB-mode, the trend is different, as can be seen in Figure 5.2. Operating the plants in HOB-mode shows a clearly linear trend with an increasing amount of heat being maintained with increasing α. The trend can be explained by the lack of electricity available to be traded for CCS in plants designed with low power to heat ratio. Plants with an α above 0.5 have a heat production capacity that is above the plants maximum heat production capacity without CCS. Biomass plants have a slightly lower heat production with CCS, since the carbon content in the flue gases is expected to be higher, thus, increasing the reboiler duty. In CHP-mode the same difference with fuels exists, however, other factors such as difference in plant design will also have an effect on the output. The two levels are therefore not as clear in Figure 5.1.

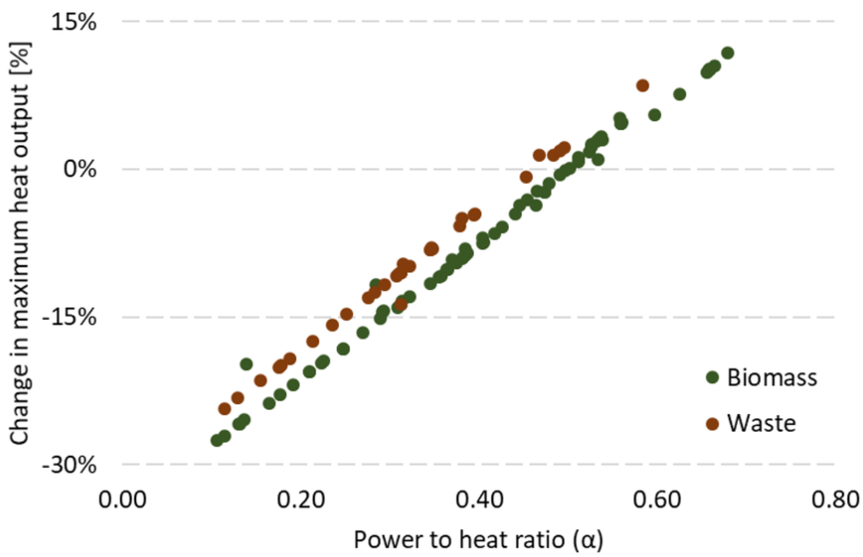


Figure 5.2: Change in maximum heat output for CHP plants with CCS, when operated in HOB-mode. The α values are for the plants without CCS integrated.

Figure 5.3 shows the relationship between the total efficiencies for all plants, and the specific reboiler duty. The trend seen in Figure 5.3 is linear and the plant level results can therefore easily be scaled for different specific reboiler duties. Based on studies done on heat requirement for CCS, there are several different factors that will determine the actual reboiler duty required. The size of the equipment needed and the concentration of carbon in the flue gases are just examples of things that will affect the actual specific reboiler duty, and these aspects have not been considered in this project. With a high specific reboiler duty, the total efficiency of heat and electricity production of the plant can decrease by up to 40 %, as can be seen in Figure 5.3.

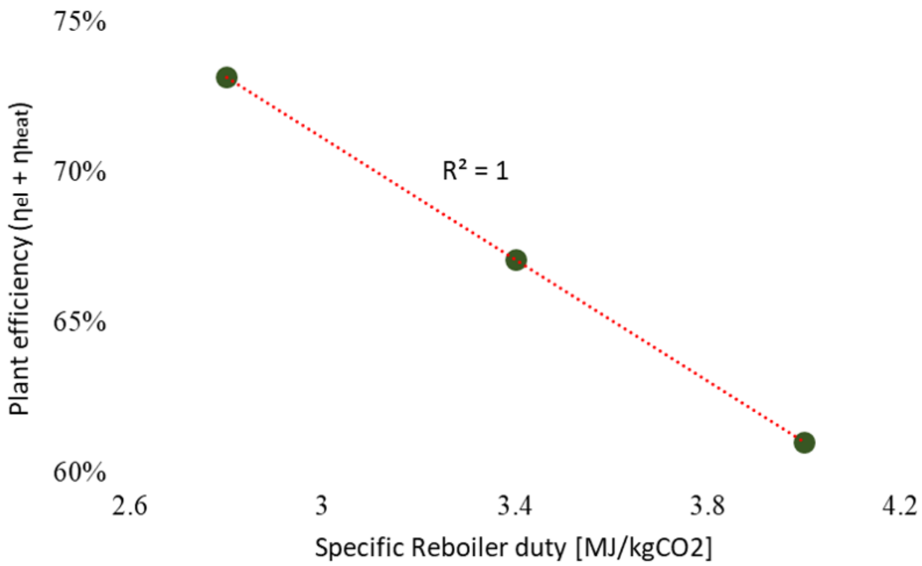


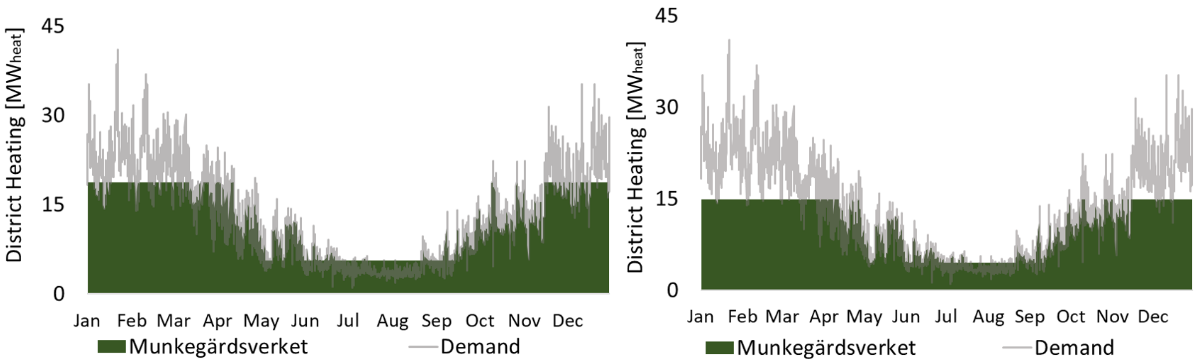
Figure 5.3: A sensitivity analysis of the plant efficiencies with different specific reboiler duties for the CCS reboiler. Note that axes are cropped to show the trend.

5.2 Impact on DH systems when CHP is operated with CCS integration

This section investigates how the operations of CHP plants integrated with CCS will affect the DH systems. The section includes results from the four cases presented in Table 4.5. For each case, examples of DH networks are discussed and plant operating profiles are compared. The final section (5.3.2) presents a comparison of the key performance indicators, calculated for each case. A specific reboiler duty of 3.4 $MJ/kgCO_2$ is used throughout these results, however considering the linear relationship presented in Figure 5.3, the actual reboiler duty may vary.

5.2.1 Case 1 - all plants in DH system operating with CCS in CHP-mode

When implementing CCS on all plants and operating the plants with CCS at all times in CHP-mode, both heat and electricity outputs are lower than without CCS. A lower heat output will make it more difficult to meet DH demand and during the hours when CHP is normally operated on full load, heat delivery is reduced. The clearest way to see this is from a DH network with only one plant. Figure 5.4 shows how the biomass plant, Munkegärdsverket operates in the context of the Kungälv DH network. The demand profile is shown as the grey line and the plant operation is the green blocks. During the winter the plant is operated at maximum load and even without CCS the demand cannot be fulfilled with CHP alone. During the summer, the demand can be fully satisfied with CHP, however to reach the same heat output with CCS, the fuel consumption for the CHP must be increased. Due to the constraint of a minimum load of 30 % for biomass plants, some excess heat is produced during the summer. In reality, plants producing a lot of excess heat are shut down unless the heat can be used for some other purpose.



(a) Without CCS (b) With CCS

Figure 5.4: Heat demand and plant operating profile for Kungälv when the CHP plant is operated without CCS and with CCS using CHP-mode.

Most of the larger DH networks have more than one plant in the system. Jönköping has a DH network containing two plants, one small waste plant and a biomass plant.

According to the dispatch order, the waste plant will serve as the base load, shown in brown and the biomass plant operations are displayed in green. The effect of having more than one plant can be seen for Jönköpings district heating system in Figure 5.5.

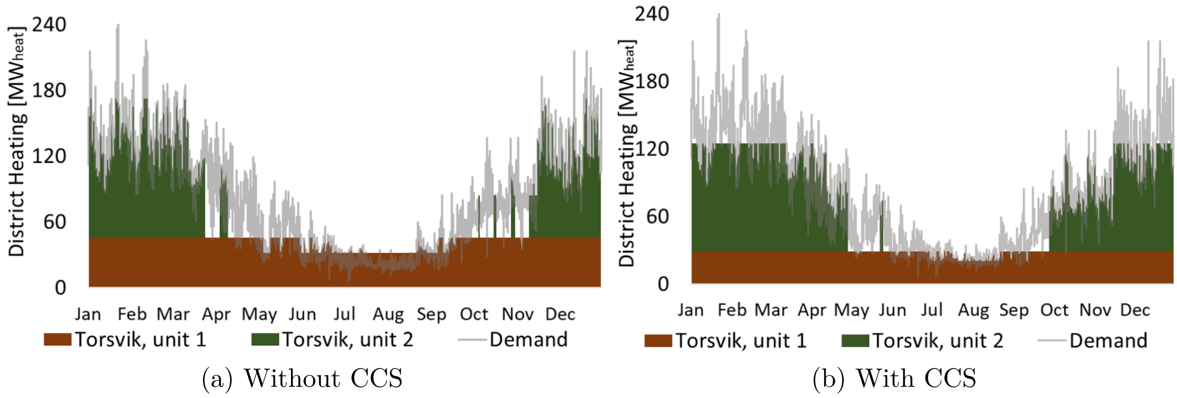


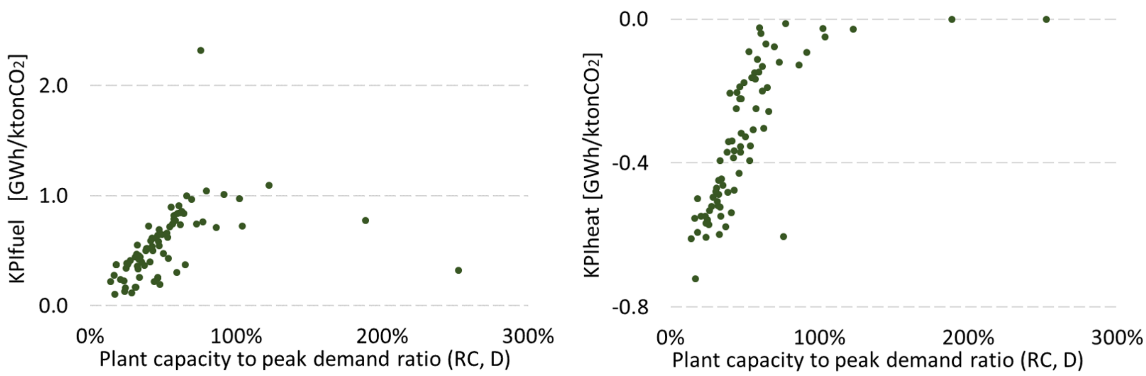
Figure 5.5: Heat demand and operating profile of Jönköpings CHPs using CHP-mode, with and without CCS.

With more than one plant in the system, as can be seen in Figure 5.5, the operating pattern is affected by the dispatch order and constraints set on the system. The operation of systems with multiple plants tend to be more flexible than what the model can handle, it may for example be profitable to run several plants on part load when demand is low, rather than shutting a plant down. The distribution of load between the different plants may therefore not be entirely comparable to reality, however the results as a whole give an indication of how the system is affected. The transition months, March until May and October until November shows the largest flaws in the model. Demand fluctuates during this period and based on the constraints for operation, the biomass plant cannot operate most of this period for the system without CCS. With CCS however, the plants can operate for a longer time without being limited by the constraints. The key performance indicators, KPI_{fuel},KPI_{heat} and KPI_{el} as well as the carbon capture for the Jönköping and Kungälv DH systems are given in Table 5.1.

Table 5.1: Key performance indicators and carbon captured for Jönköping and Kungälv DH systems. The carbon capture is the annual carbon capture potential and the KPI's are in the unit GWh/ktonCO_2.

City	Total CO_2 capture (ktonCO_2)	Fossil CO_2 capture (ktonCO_2)	KPI_{fuel}	KPI_{heat}	KPI_{el}
Kungälv	53	0	0.26	- 0.22	- 0.09
Jönköping	376	80	0.84	- 0.02	0.05

As shown in Table 5.1, the KPI_{fuel} for Jönköping is large, therefore the CHP fuel increase required for the Jönköping DH system is large. However the amount of heat delivered from CHP is almost unchanged, which can be seen from KPI_{heat} being close to zero. In Kungälv, KPI_{fuel} is lower than for Jönköping. A lower KPI_{fuel} is compensated for with less CHP heat delivery, which is seen in the negative KPI_{heat} value. The inverse relationship between KPI_{fuel} and KPI_{heat} is true for most networks. A large negative value for KPI_{heat} will often correspond to a low KPI_{fuel}. The operating pattern will determine which of the two performance indicators will be the highest. When CHP can cover all of DH demand, indicating that CHP capacity is large in relation to the demand, KPI_{fuel} is more affected than KPI_{heat}. KPI_{heat} is in turn largely affected when the CHP capacity is not large enough to cover the DH demand. When comparing the operating profiles seen in Figures 5.4 and 5.5, the CHP can cover more of the peak demand in Figure 5.5 than in Figure 5.4. The ability to meet peak demand is based on the CHP heat capacity compared to the peak demand. This relationship is what has been defined as $\text{R}_{C,D}$, the ratio of capacity to demand. The $\text{R}_{C,D}$ will determine the KPI_{fuel} and KPI_{heat}, which can be seen in Figure 5.6.



(a) Fuel performance indicator, KPI_{fuel} (b) System heat performance indicator, KPI_{heat}

Figure 5.6: KPI_{fuel} and KPI_{heat} for all DH networks given for case 1.

In Figure 5.6a the networks with large $\text{R}_{C,D}$ will in most cases have a higher KPI_{fuel}. A high KPI_{fuel} indicates that all the heat needed can be delivered with CHP for many hours of the year. The plants with an $\text{R}_{C,D}$ above 100 % , do not follow the same trend of an increased fuel consumption. When the plant capacity is large in relation to the DH demand, the fuel consumption is already very high, due to excess heat production during the summer. Implementing CCS on such plants will therefore not impact the fuel consumption to the same extent. Arguably, these plants are usually not operated at all during the summer, since excess heat production requires cooling. As seen in Figure 5.6b, plants with a large $\text{R}_{C,D}$ will hardly have any reductions in CHP heat delivery, whereas plants with small $\text{R}_{C,D}$ have less heat in the CHP system.

5.2.2 Case 2 - all plants in DH system operating with CCS in HOB-mode

Case 2 looks into the option of operating all CHP plants in DH systems in HOB-mode when integrated with CCS. The objective of this is to limit the increase in fuel consumption, as well as fulfil the total system heat demand using CHP plants as much as possible. As seen in Figure 5.2, the maximum heat output from CHP operated in HOB mode will vary between 70 - 110 % of the heat output without CCS, depending on the α value of the plant. This means that for some of the networks, containing plants with low α values, heat delivery cannot be sustained, when operating in HOB-mode. No electricity is produced when operating in HOB-mode, KPI_{el} should therefore be the most prominent indicator for case 2.

Operating the two plants in the Jönköping DH network in HOB-mode gives a lower heat output than without CCS, since the plants have low α of 0.29 and 0.31 respectively. The Eskilstuna DH network consists of one plant with a high α of 0.53. A comparison of the key indicators and carbon capture for the Jönköping and Eskilstuna DH network operated in HOB-mode is presented in Table 5.2.

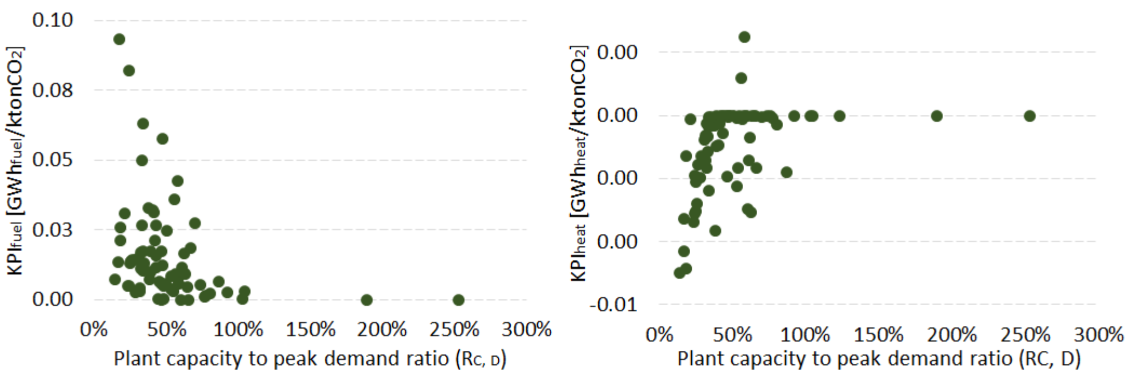
Table 5.2: Key performance indicators for Jönköping and Eskilstuna DH networks operating in HOB-mode. The carbon capture is the annual carbon capture potential and the KPI's are in the unit GWh/ktonCO_2

City	Plant α values	Total CO_2 capture (ktonCO_2)	Fossil CO_2 capture (ktonCO_2)	KPI_{fuel}	KPI_{heat}	KPI_{el}
Jönköping	0.29 and 0.31	308	80	0.31	0.00	- 0.59
Eskilstuna	0.53	242	0	- 0.03	- 0.03	- 0.93

For both Jönköping and Eskilstuna, the CHP heat delivery is completely maintained as seen in Table 5.2. The fuel consumption will however increase for Jönköpings CHP plants. In Eskilstuna, only the electricity is changed. The KPI_{el} for both Eskilstuna and Jönköping is high. In this case, it is clear that α will determine the degree to which heat can be delivered and fuel is unaffected. The electricity production will however decrease more with increased α. Plants with large α are more likely to be the most dependent on income from electricity production and therefore least likely to reduce electricity production. If HOB-mode is to be considered, it should be set in contrast to the electricity prices. It could be possible to operate in HOB-mode only when electricity prices are low.

5.3 Case 3 - all plants in the DH system operated with CCS during the summer in CHP-mode

Case 3 investigates the option of only utilising CCS during the summer. The reason for this case study is to, through the utilisation of excess heat, keep the CHP heat delivery (KPI_{heat}) low while still capturing some of the carbon emissions. Thus, the performance indicators of interest are mainly in the aspect of fuel, KPI_{fuel} and heat, KPI_{heat} which, for Case 3, are presented in Figure 5.7.

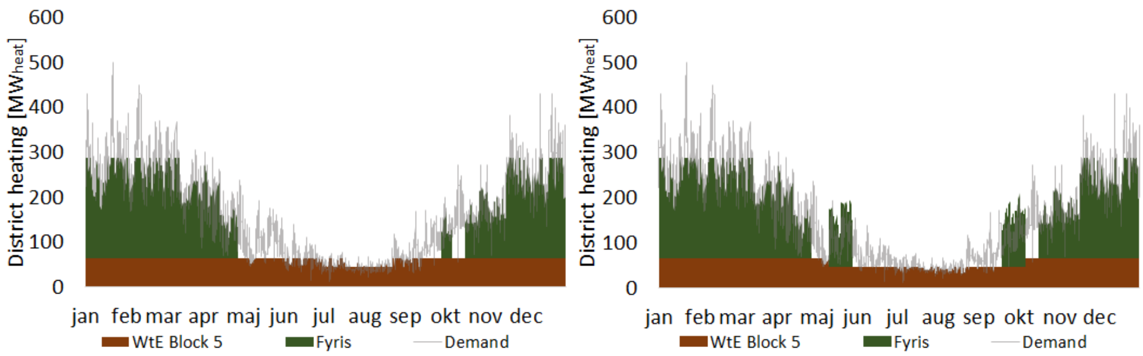


(a) Fuel performance indicator, KPI_{fuel} (b) System heat performance indicator, KPI_{heat}

Figure 5.7: KPI_{fuel} and KPI_{heat} for all DH networks given for case 3.

It can be seen in Figure 5.7a, that KPI_{fuel} has a decline proportional to the plant capacity to peak demand ratio, $R_{C,D}$, at the right-hand perimeter. This implies that KPI_{fuel} has a cap which decreases as $R_{C,D}$ increases. In order for KPI_{fuel} to reach zero, the plants must have an equal fuel input both with CCS and without CCS during the summer, which only occurs when the plants, both with and without CCS, follow the same operational pattern. This only happens when the plant is operated at either minimum or maximum load for the entire summer. Since the heat demand is generally satisfied during the summer, the latter can be disregarded. In Figure 5.7b it can be seen that, similar to KPI_{fuel}, the discrepancy in KPI_{heat} decreases as $R_{C,D}$ increases meaning that larger plant capacities in comparison to the network peak demand are less affected by an integration with CCS. It can therefore be stated that the fuel consumption and delivered heat are both affected to the better with increasing $R_{C,D}$.

Since the CCS units are only operated during the summer, the discrepancy that the CCS evokes occurs not only during the summer, but also in the transition from spring to summer, in May, as well as summer to autumn, in September. This is well illustrated in Figure 5.8, which shows the operation profiles of Uppsalas CHP plants.



(a) Without CCS (b) With CCS

Figure 5.8: Annual operation profiles for the DH network in Uppsala, b) shows when plants are operated with CCS during the summer period.

It can be seen in Figure 5.8 that the demand is not fully satisfied either with or without CCS. Further, it can also be seen that the biomass plant (Uppsala CHP 1 (Fyris) B) is run during the seasonal transition with CCS, in contrast to it not being operated during this period without CCS which results in an unexpected reduction in KPI_{heat}. The extra blocks that can be observed in Figure 5.8, in the seasonal transitions, are a consequence of the assumption that a biomass plant cannot be operated at a part load lower than 30 %. If the base load would have been slightly smaller, the secondary plant would have operated during the period even if the CCS would not have been integrated, leading to the two operational blocks that appear in May and September in Figure 5.8a as well. Their heat production and delivery should in reality be more equal than what is observed from these results. Another consequence of a smaller base load would be a prolonged operation of the secondary plant during the transition from spring to summer, and late summer to autumn for the process integrated with CCS, which would maintain the discrepancy between the heat production between the two cases. In Table 5.3, emissions and key performance indicators for Uppsala's DH network are presented.

Table 5.3: Results from Case 3 on Uppsala DH network

City	Total CO_2 capture ($ktonCO_2$)	Fossil CO_2 capture ($ktonCO_2$)	KPI_{fuel}	KPI_{heat}	KPI_{el}
Uppsala	56	26	3.62	0.12	0.69

As can be seen from Table 5.3, the KPI_{fuel} is high. The large increase in fuel consumption is to a large extent due to the prolonged plant operations in the transition periods. For case 3, the total amount of carbon captured cannot cover the total fossil share of emissions on an annual basis. As presented in Table 5.3, the amount of carbon captured is 56 kton per year. The total amount of emissions however, are still at 848 kton per year for when the CCS is active, where 138 kton CO_2 is of fossil origin. In other words, the amount of captured carbon corresponds to about 40 % of the total amount of fossil emissions from the network. Among the DH networks, the one with the highest coverage of fossil emissions with this strategy is Stockholm city. The Stockholm city system can still only capture CO_2 corresponding to about 68 % of the fossil emissions with this operational strategy. Hence, it can be stated that if the fossil quota of a networks emissions are sought to be covered by the carbon capture, the CCS must be operated more than just throughout the summer.

5.3.1 Case 4 - Base load operated with CCS in CHP-mode

Installing CCS on all plants in a DH network is a large investment, especially installing it on plants that are not operated throughout the year. This case will look at the impact of only installing CCS on the base load plant, i.e the first plant in the dispatch order. Case 4 therefore aims to maintain a high amount of carbon capture without sacrificing too much of the CHP heat delivery. It is especially interesting to look at networks where the base load covers either a particularly large or small portion of the total network capacity. In Table 5.4, the results for Lund, which has a large base load in comparison to total capacity, and Stockholm city, whose base load makes up only about 16 % of the total capacity, are presented.

Table 5.4: Key performance indicators for Lund and Stockholm city. The carbon capture is the annual carbon capture potential and the KPI's are in the unit GWh/ktonCO$_2$.

DH network	Base load proportion (%)	KPI$_{fuel}$ (GWh/ktonCO$_2$)	KPI$_{heat}$ (GWh/ktonCO$_2$)	KPI$_{el}$ (GWh/ktonCO$_2$)
Lund	87.8	0.44	-0.50	-0.01
Stockholm city	16.1	0.77	-0.33	0.12

As can be seen, KPI$_{fuel}$ is lower for Lund, implying that a network with a large base load utilises the fuel better. However, Stockholm city has a higher KPI$_{heat}$, meaning that the impact on the heat supply is smaller when the base load makes up a lower portion of the total capacity. When the base load is small, the system operating pattern is quite similar between with or without CCS. The reason for this is the base load not having any significant impact on the heat demand fulfilment in the system. The plant would have to operate at full load most of the year, regardless of CCS. Other plants in the system cover the decreased heat production from the base load, leading to a KPI$_{heat}$ closer to zero. Although, a smaller base load is positive in the heat and electricity production aspects, it does however come at the cost of an increase in total fuel consumption.

Like in Case 3, it is interesting to investigate whether the total carbon capture can cover the emissions with fossil origin. Naturally, the size of the base load is the determining factor, and for Stockholm city, meeting the fossil emission part is feasible. The ability to capture the fossil share of the emissions will depend on which plant is set as base load. The dispatch order will therefore be changed to understand how different sized plants will affect the ability to cover all fossil emissions. In Table 5.5, the key performance indicators for Stockholm city with different plants as base load are given. The dispatch order is changed in such a way that Plant 1 is switched with either plant 2, 3 or 4 while the remaining plants have their dispatch order unchanged.

Table 5.5: Key performance indicators for Stockholm city with different plants as base load. The dispatch order numbers correspond to the dispatch order in case 1. Each sequence has base loads corresponding to 17.0 %, 8.2 %, 38.9 % and 36.0 % of the total network capacity, respectively. The KPI's are in the unit GWh/ktonCO$_2$

Sequence	Dispatch order	Fossil emission equivalent captured (%)	KPI$_{fuel}$	KPI$_{heat}$	KPI$_{el}$
A	1, 2, 3, 4	123	0.77	-0.33	0.12
B	2, 1, 3, 4	77	0.47	-0.31	-0.04
C	3, 2, 1, 4	731	0.66	-0.26	-0.02
D	4, 2, 3, 1	650	0.98	-0.18	0.09

As can be seen in Table 5.5, the only sequence which cannot cover the fossil emission equivalent is Sequence B. Both Sequence A and B have waste plants as base loads, however, only Sequence A can achieve a coverage of the fossil share of emissions. To determine which plant should be fitted with CCS, it may be intuitive to chose a plant that releases fossil emissions, such as a waste plant. The results presented in Table 5.5 make it clear that it is more important to consider the size of the plant rather than the fuel used, when determining which plant should be fitted with a CCS unit. In terms of the key performance indicators, Sequence A performs best with regards to KPI_{el}. Thus, sequence A would be the best option if electricity is the most favoured CHP output. However, if KPI_{heat}, which is the primary output of CHP, is favoured, sequence D would be the better option. Sequence C is slightly worse than D, with regards to KPI_{heat}. Based on this case study, having CCS installed only on the base load is attractive for DH networks with large plants as base load. Yet, since the results vary depending on the base load capacity, a thorough investigation of which plant should be retrofitted with CCS must be done.

5.3.2 Comparison of the four cases of CHP operation with CCS integration

On a national level, the four cases will lead to different results regarding the aggregated CO_2 emissions captured from all DH networks in Sweden. The results from the system are shown for all four cases on a national level in Table 5.6.

Table 5.6: A nationwide case comparison. The fuel, heat and electricity is shown as the change in production and consumption between the system with CCS and the system without CCS. The results are based on operation for one year.

Case	Total CO_2 capture ($MtonCO_2$)	Fossil CO_2 capture ($MtonCO_2$)	Change in fuel consumption (TWh)	Change in heat delivered (TWh)	Change in electricity produced (TWh)
Case 1 - full CHP-CCS	17.1	2.8	+ 10.6	- 5.5	+ 0.3
Case 2 - full HOB-CCS	14.1	2.7	+ 1.1	- 0.4	- 11.5
Case 3 - summer CHP-CCS	2.5	0.7	+ 4.0	- 0.3	+ 0.3
Case 4 - base load CHP-CCS	10.5	2.6	+ 7.0	- 2.2	+ 1.5

Case 1 will lead to the largest amount of carbon captured, the plants are both operated more and CCS is run at all times. Fuel must however be increased with more than 10 TWh and CHP heat delivery cannot be maintained. The carbon capture for Case 2 is lower than for Case 1, however, the emissions avoided are almost equivalent. Base load CCS includes most waste plants, therefore the fossil share of the carbon capture is almost equivalent in Cases 1 and 4. Summer CCS has a considerably lower carbon capture potential.

Currently, Sweden's CO_2 budget is decreasing and with this in mind, a greater carbon capture is an attractive trait for a network. The goal for negative emissions is to correspond to 15 % of 1990's total fossil emissions, which is equal to 11 Mton/year. In comparison, the total potential for BECCS in Sweden's CHP can cover the negative emissions goal on its own, if CCS is implemented in line with Case 1 or 2. For Case 3, the emission reduction is far from enough to cover this carbon capture from CHP alone and will thus need supplementary measures. If only the base loads would be equipped with CCS, as in Case 4, the BECCS would add up to 7.9 Mton per year which is insufficient on its own. However, the fossil share of carbon captured is almost equal to that of Case 1 and 2, implying that by installing CCS on base loads is an effective way to reduce fossil emissions.

The effect the different cases have on the system as a whole cannot be compared without looking at the key performance indicators. As seen for the previous parts of this chapter, the key performance indicators will vary between both cases and DH networks. The key indicators have been calculated for the national system as a whole, thus the difference between different DH systems will not be reflected in the results shown in Figure 5.9. Figure 5.9 shows how the three key indicators compare for the four cases.

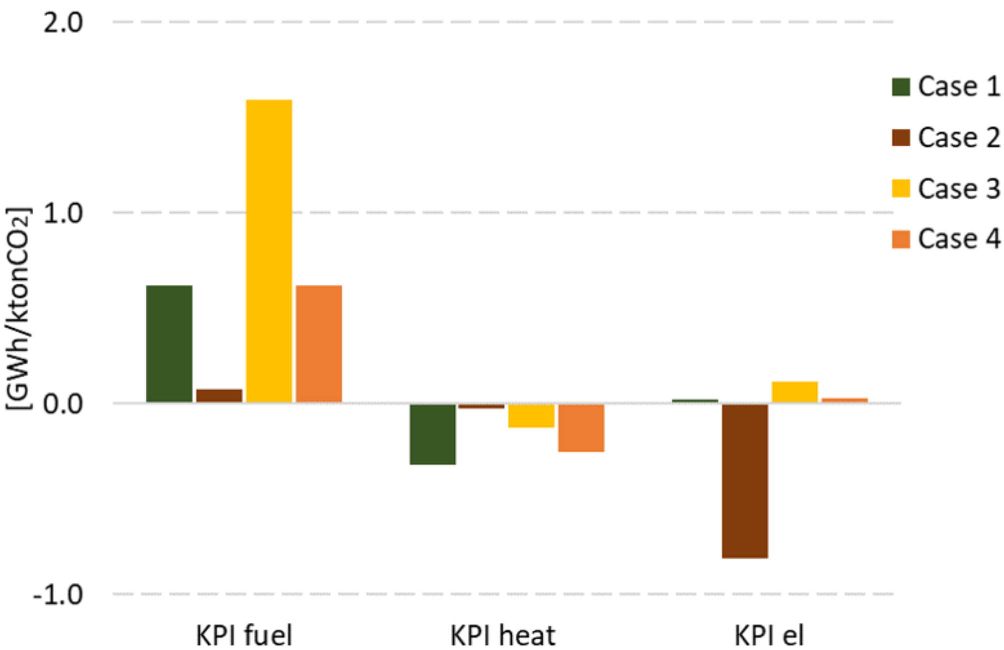


Figure 5.9: Key performance indicators based on the national averages of all cases.

Figure 5.9 shows that, KPI_{fuel} is highest for the case with summer CCS. KPI_{heat} is negative for all cases, indicating that there is no system where the CHP heat production can be maintained with CCS. In Case 2, the main indicator is the electricity loss, while for all other cases, the KPI_{el} is positive. Case 1 and Case 4 are fairly similar in all areas, the largest difference is that Case 4 can maintain more heat delivery.

In order to fully justify which indicator should be kept the lowest, the inputs and outputs must be quantified against something measurable, such as costs. Since this project has not considered costs, the discussion on which indicator relates to the most desired outcome will be based on system knowledge. A large negative value of KPI_{heat} relates to a reduction of heat delivered from CHP. A reduction in heat delivery from CHP will lead to an increased need to operate other plants in the system. Other plants may be fuelled with more expensive fuel types or with fossil fuel sources. An example of this is Gothenburg, where a part of the heat supply during the winter comes from natural gas. Installing CCS in a manner that would increase the use of other fossil plants could defeat the point of installing CCS altogether.

Regarding the KPI_{el}, it is difficult to draw any conclusions on how a decreased electricity production would impact the system. Electricity production is not the main purpose of CHP and in many cases cheap and environmentally friendly electricity can replace the electricity produced using CHP. To measure the actual consequences of reducing electricity production, a dynamic model, considering electricity costs must be implemented on the system. Electricity is also needed for the compression steps in CCS. This aspect has not been considered this far in the project and it is assumed that electricity will always be available for compression. About 3.8 MJ/kgCO_2 of electricity is required to reach 100 bar, this relates to - 1.05 GWh/ktonCO_2, more than doubling the KPI_{el} value for Case 2.

A large KPI_{fuel} has to be set in perspective of fuel cost and availability. MSW is often readily available and cheap to incinerate, therefore waste plants are preferably operated as much as possible. Unfortunately, waste plants already serve as the base load in many DH networks and are operated a lot already. Several different fuel types have been categorised as biomass in this project. The diversity in the types of biomass is large when it comes to both availability and cost.

With all determining factors in mind, regarding inputs, outputs and plant- and network constituents, it is important to highlight that all case models have advantages over each other. No case model is a clear solution and, in reality, a combination of them would give the best results. Optimally, the plants' CCS should be adapted to match the individual networks. By managing the operation of CCS and the mode of the CHP, an even more dynamic and well performing system can be achieved.

Capital costs are not considered in this project. Fitting all plants with CCS is expensive and for some of the smaller plants, were only about 20 kton CO_2 can be captured each year, the installation and infrastructure costs are probably too high to compensate for the carbon capture. It would be more cost effective to only focus on large CHP plants with large CO_2 emissions. Plants that only have a few full load hours each year are the least cost effective option for CCS, therefore it may be of interest to only install CCS on the plant that serves as the base load of the process. The capital cost is also effected by the size of the unit required, if the plant is run at below maximum capacity for many hours of the year, for example if the $R_{C,D}$ is high, it may be of interest to dimension CCS for a lower capture rate.

6
Conclusions

This thesis has investigated the CO_2-reduction potential of implementing Carbon Capture and Storage (CCS) on Sweden's Combined Heat and Power (CHP) plants. The implementation of CCS was evaluated on both process and system level. The process approach investigates how CCS implementation will affect the heat generation from all CHP processes in Sweden. In the system approach, the impact of CCS integration with CHP on the district heating system is evaluated, for four cases of CCS operations. To evaluate the effect CCS has on the energy system, three performance indicators were derived- fuel consumption, heat delivery and electricity generation relative to the amount of CO_2 captured.

The study showed that features within both the CHP plant and the DH network will determine the best operation of a plant with CCS. On process level, the power to heat ratio of the plant will impact CCS implementation. For the system perspective, the size of the CHP plants in the system, in relation to the peak demand is the most determining factor, when analysing how CCS influences the system performance. Fuel consumption will increase, regardless of which mode or operating pattern CCS is installed with, and CHP as well as non-CHP fuel cost will strongly impact the willingness to install CCS. The increase in fuel consumption can, however, to a large extent, be off-set for reduced electricity generation if the CHP plants are operated in HOB-mode. Maintaining district heating delivery from CHP plants is necessary to avoid emissions from other sources that counteract CO_2 capture. On average, the CHP heat delivery will be reduced for all system cases. However, within each case, there are district heating networks that can maintain CHP produced district heating with CCS installed, even though it often comes with the cost of an increased fuel consumption. To optimise operations of CCS on CHP, mixing different modes and operating patterns should be considered.

Implementing CCS on all Swedish biomass and waste CHP plants, for all operational hours of the year, will exceed the negative emissions goal of 11 MtonCO_2/year. This study shows that there is no method of operation that fits every district heating system, but instead, a combination of every operational method would generate the best results. Due to Sweden's district heating systems being unique, they must be treated as such. Sweden still has a long way to go before reaching the emissions goal and understandably not all CHP plants will be integrated with CCS in a near future. In a lot of discussions on CCS, large point sources of emissions are seen as a priority for CCS. This study shows that it is also important to take the plant and system features into account.

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A

Appendix

A.1 Database

District heating Network	Energy company	Total delivered DH (GWh)	Plant Name	Fuel	Steam Cycle Parameters			
					Q_{heat} (MW)	W_{el} (MW)	P_{steam} (bar)	T_{steam} (C)
South								
Borås	Borås Energi och Miljö AB	598	Sobacken	B	74	42	140	540
			Ryaverket G1	B	50	20	50	500
			Ryaverket G2	W	60	25	50	405
Upplands-Bro	Eon	425	Högbytorp WtE	W	70	29	50	420
Eksjö	Eksjö Energi	107	Eksjö Energi KVV	W	18	2	16	-
Enköping	ENA Energi AB	213	ENA Kraft KVV	B	45	24	100	540
Eskilstuna	Eskilstuna Energi och Miljö	628	Eskilstuna KVV	B	71	35.5	139	540
Göteborg	Göteborg Energi	3528	Sävenäsverket, HP 3	B	82	13	20	-
			Sävenäs KVV	W	126	42	40	400
Halmstad	HEM AB	575	Oceanen	B	14.3	3.2	56	480
			Kristinehedsverket	W	33	9	40	400
Hässleholm	Hässleholm Miljö AB	179	Beleverket	B	18	2	-	-
Helsingborg	Öresundskraft AB	1032	Filbornaverket	W	60	18	49	425
			Västhamnsverket	B	138	69	130	540

Figure A.1: Page 1 of 4 of table containing the plants located in the south of Sweden, investigated in this project. Fuels are either W - Waste or B - Biomass.

Jönköping	Jönköpings Energi	710	Torsvik 1 KVV	W	42	14	41	380
			Torsvik 2 KVV	B	100	35	139	540
Kalmar	Kalmar Energi	368	Moskogen KVV	B	60	30	143	540
Karlskoga	Karlskoga Energi och Miljö	305	Karlskoga KVV	W	50	15	28	300
Karlskrona	Affärsverken i Karlskrona AB	243	Bubbetorp KVV	B	30	13	90	480
Katrineholm	Tekniska Verken i Linköping	170	PC Väster	B	15.6	5.4	40	400
Kristianstad	C4 Energi	356	Allöverket 1	B	36.7	15.3	68	513
			Allöverket 2	B	23.3	8.7	68	513
Kungälv	Kungälv Energi	116	Munkegärdsverket	B	20	2.6	25	224
Landskrona	Landskrona kraft	254	Energiknuten KVV	B	22	7	74	450
Lidköping	Lidköping Energi	220	Filen Panncentral T1	W	36	4	16	-
			Filen Panncentral T2	W	24	6	30	-
Linköping	Tekniska Verken i Linköping	1314	Gärstadverket, Glashuset	W	75	19	40	400
			Gärstadverket, Lejonpannan	W	60	21	40	400
			Linköping KVV	B	41	22	59	475
Ljungby	Ljungby Energi	143	Ljungsjö 1	W	12	3	16	220
			Ljungsjö 2	B	13	1.6	16	220
Lund	Kraftringen Produktion AB	836	Återbruket	B	10	4	61	510
			Örtofta 1	B	79	35	112	540
Malmö	SYSAV	2074	Sjölunda 1	W	65	20	40	400
			Sjölunda 2	W	65	20	40	400
Mariestad	VärnerEnergi AB	128	Mariestad KVV1	B	26	9.5	80	480
			Mariestad KVV2	B	27	7.3	62	475

Figure A.2: Page 2 of 4 of table containing the plants located in the south of Sweden, investigated in this project. Fuels are either W - Waste or B - Biomass.

Kinna/Skene/ Örby	Mark Kraftvärme AB	93	Assbergsverket	B	23	3.5	50	440
Mjölby	Mjölby-Svartådalen Energi AB	176	Mjölby KVV	B	23	10.8	80	500
Mölndal	Mölndal Energi AB	381	Riskulla	B	46	24	123	520
Motala	Vattenfall	151	Bergsättersverken	B	16	3.75	16	-
			Motala KVV	B	16	3.7	-	-
Nacka /Haninge	Vattenfall	468	Jordbro KVV	B	43	20.3	82	473
Nässjö	Nässjö affärsverk	151	Nässjö KVV	B	26	9	80	490
Norrköping	Eon	901	Händelöverket G11	B	153	89	110	535
			Händelöverket G13	W	83	40	65	450
Norrtälje	Norrtälje Energi AB	124	Arstaverket	B	15	6.4	70	485
Nybro	Nybro Energi AB	144	Transtorp	W	16	6	60	410
Nyköping	Vattenfall	271	Idbäcksverket	B	60	35	143	543
Oskarshamn	Oskarshamn Energi	149	Solkustens KVV	B	17	3.8	-	-
Sala Heby	Sala Heby Kraftvärme AB	146	Silververket	B	23	9	80	480
Skövde	Skövde Värmeverk AB	359	Värmekällan Block 4	B	29	9	90	480
			Värmekällan WtE	W	13	1.7	16	215
Södertälje	Tälje Nät AB	688	Igelsta KVV	B	155	85	89	540
North Stockholm	Stockholm Exergi	1950	Bristaverket 1	B	74	42	144	540
			Bristaverket 2	W	57	16.8	60	415
Stockholm South/City	Stockholm Exergi	6170	Värtaverket KVV1	B	330	210	177	535
			Värtaverket KVV8	B	215	130	140	560
			Högdalen G1	W	71	27	36	400
			Högdalen G6	W	115	44	60	480

Figure A.3: Page 3 of 4 of table containing the plants located in the south of Sweden, investigated in this project. Fuels are either W - Waste or B - Biomass.

Strängnäs	SEVAB	149	Strängnäs KVV	B	27	9	72	427
Tidaholm	Tidaholms Energi AB	53	Eldaren	B	8	2.2	40	-
Tranås	Tranås Energi	124	Södra Vakten 1	B	10	1.8	15.2	345
			Södra Vakten 2	B	18	7	-	-
Trollhättan	Trollhättan Energi AB	346	Lextorp KVV	B	13	3.6	51	485
Uddevalla	Uddevalla Energi AB	302	Lillesjöverket	W	33	10	40	400
Uppsala	Vattenfall	1419	Fyris KVV	B	235	120	192	535
			Uppsala, block 5 WtE	W	50	10.2	16	210
Värnamo	Värnamo Energi	144	Värnamo KVV	B	12	4	51	485
Västerås	Mälarenergi	1419	Aros KVV, block 5	B	110	60	74	540
			Aros KVV, block 6	W	110	48.5	75	470
			Aros KVV, block 7	B	100	50	91	520
Västervik	Västervik Miljö och Energi	177	Stegeholmsverket	W	15	5	-	410
Växjö	VEAB	535	Sandviksverket 2	B	65	35	142	540
			Sandviksverket 3	B	65	39	140	540
Vimmerby	VEMAB	102	Tallholmen	B	15	7.5	-	-
Örebro/Kumla	Eon/Fortum	1034	Åbyverket, GT3	B	146	24	149	540
			SAKAB Kumla WTE2	W	35	6.1	-	-
			Åbyverket, 4 (Bio 70)	B	46	24	140	540

Figure A.4: Page 4 of 4 of table containing the plants located in the south of Sweden, investigated in this project. Fuels are either W - Waste or B - Biomass.

District heating Network	Energy company	Total delivered DH (GWh)	Plant Name	Fuel	Steam Cycle Parameters			
					Q_{heat} (MW)	W_{el} (MW)	P_{steam} (bar)	T_{steam} (C)
North								
Boden	Bodens Energi AB	273	Bodens KVV P17	W	15	5	40	400
			Bodens KVV, P18	W	30	9	40	380
Bollnäs	Bollnäs Energi AB	126	Säverstaverket	W	23	7	42	423
Borlänge	Borlänge Energi	445	Bäckelund, panna 7	W	23	7	40	400
Falun	Falu Energi och Vatten AB	358	Västermalmsverket 1	B	23	7.5	63	510
			Västermalmsverket 2	B	22	8	70	500
Gällivare	Gällivare Energi AB	162	Gällivare KVP3	B	14	9	80	485
Gävle	Gävle Energi	680	Johannes KVV	B	42	23	90	480
Härnösand	Härnösand Energi och Miljö AB	181	Härnösand KVV	B	24	11.7	92	510
Hedemora	Hedemora Energi	56	Hedemora KVV	B	7	2.5	40	450
Hofors	Värmevärden i Hofors	97	Hofors KVV	B	14	1.5	25	240
Hudiksvall	Värmevärden AB	121	Djuped KVV	B	36	13	-	475
Karlstad	Karlstads Energi	577	Hedensverket 2	B	70	20	68	505
			Hedensverket 3	B	55	35	140	547
Kiruna	Tekniska Verken i Kiruna AB	200	Kiruna KVV	W	40.5	9.4	-	-
Lycksele	Skellefteå Kraft	105	Skogsbacka	B	36	14	87	520
Malå	Skellefeå Kraft	88	Malå KVV	B	10	3	41	480
Mora	Adven Enegilösningar AB	107	Siljan Timber	B	11	1.4	-	-
Munkfors	Munkfors Energi	65	Munkfors KVV	B	10	2	40	400
Sandviken	Sandviken Energi AB	215	Björksätra KVV	B	55	5.2	-	-
Säter	Hedemora Energi	50	Säter KVV	B	5	1.7	-	-

Figure A.5: Page 1 of 2 of table containing the plants located in the north of Sweden, investigated in this project. Fuels are either W - Waste or B - Biomass.

Skellefteå	Skellefteå Kraft	323	Hedensbyn	B	64	34	140	540
Söderhamn	Söderhamn NÄRA AB	126	Granskärs	B	21.5	8.5	60	510
Storuman	Skellefteå Kraft	31	Biostor	B	24	8	-	-
Sundsvall	Sundsvall Energi	549	Korstaverket 2	W	39	21	45	420
Sveg	SolörBioenergi	38	Sveg KVV	B	17	10	-	-
Umeå	Umeå Energi	854	Dåva 1	W	40	15	40	400
			Dåva 2	B	123	35	143	543
Älvsbyn	Älvsbyns Energi AB	93	Älvsbyns KVV	B	10	3	60	450
Örnsköldsvik	Övik Energi	234	Hörneborgsverket	B	70	40	139	540
Östersund	Jämtkraft	551	Lugnvik KVV	B	80	45	145	545

Figure A.6: Page 2 of 2 of table containing the plants located in the north of Sweden, investigated in this project. Fuels are either W - Waste or B - Biomass.

B

Ebsilon process models

B.1 Base process Ebsilon models

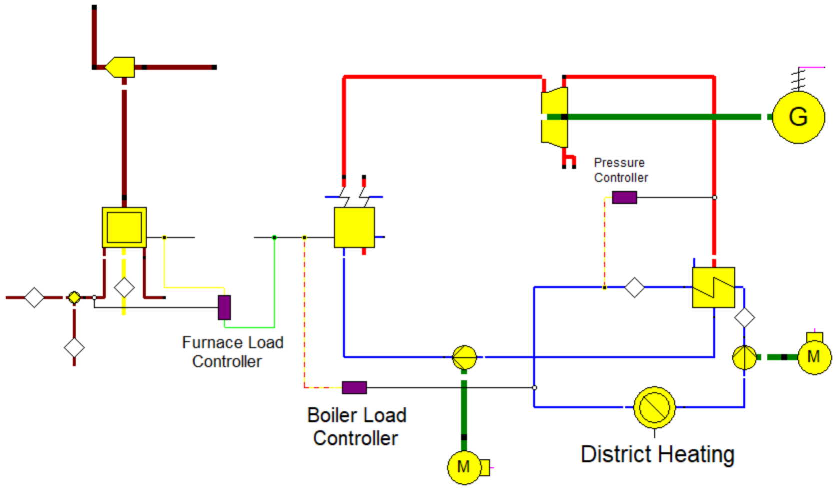

Figure B.1: Base process Ebsilon model with zero extractions (Design A).

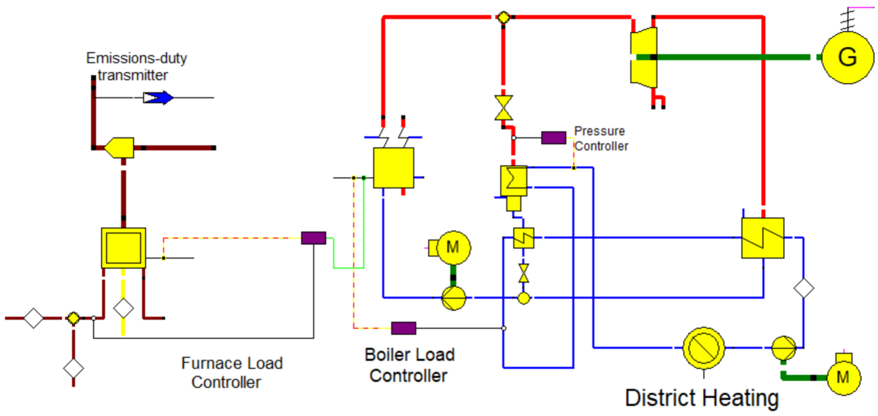

Figure B.2: Base process Ebsilon model with zero extractions and a live steam by-pass (Design By-pass).

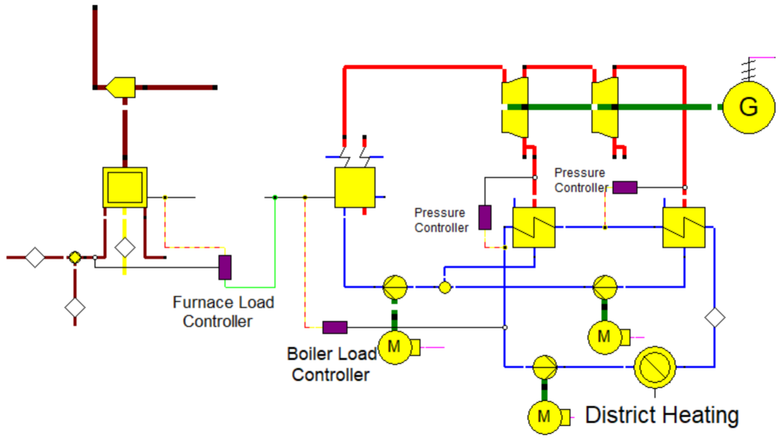

Figure B.3: Base process Ebsilon model with one extractions (Design B).

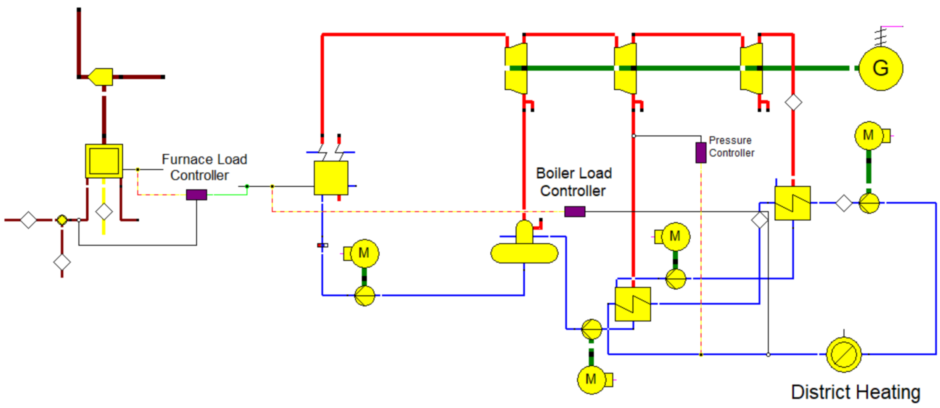

Figure B.4: Base process Ebsilon model with two extractions (Design C).

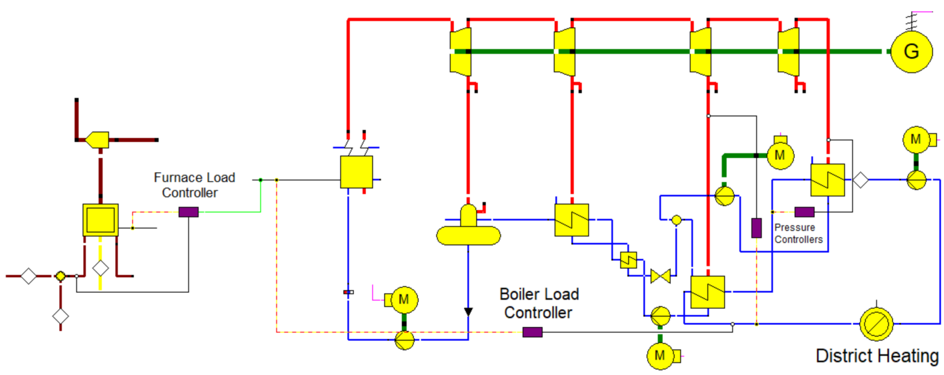

Figure B.5: Base process Ebsilon model with three extractions (Design D).

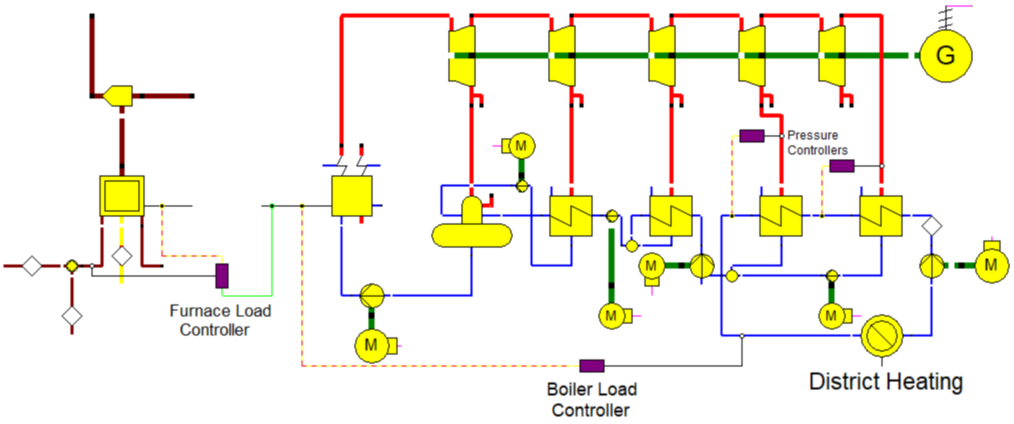

Figure B.6: Base process Ebsilon model with four extractions (Design E).

B.2 Ebsilon models integrated with CCS

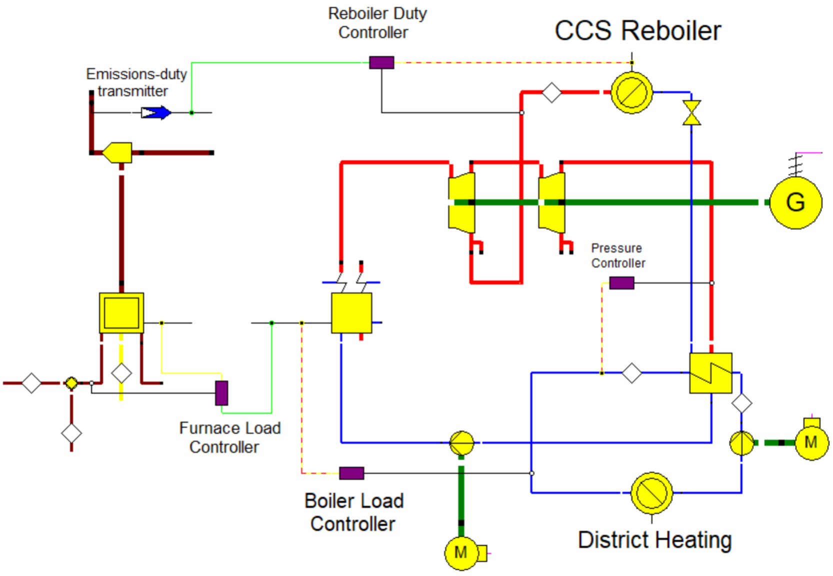

Figure B.7: Ebsilon model with zero extractions (Design A) integrated with CCS.

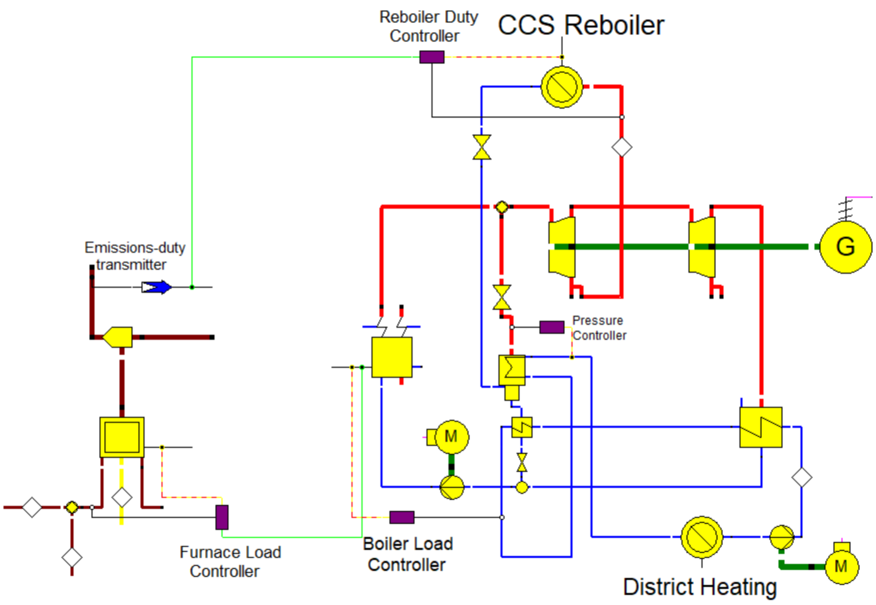

Figure B.8: Ebsilon model with zero extractions and a live steam by-pass (Design By-pass) integrated with CCS.

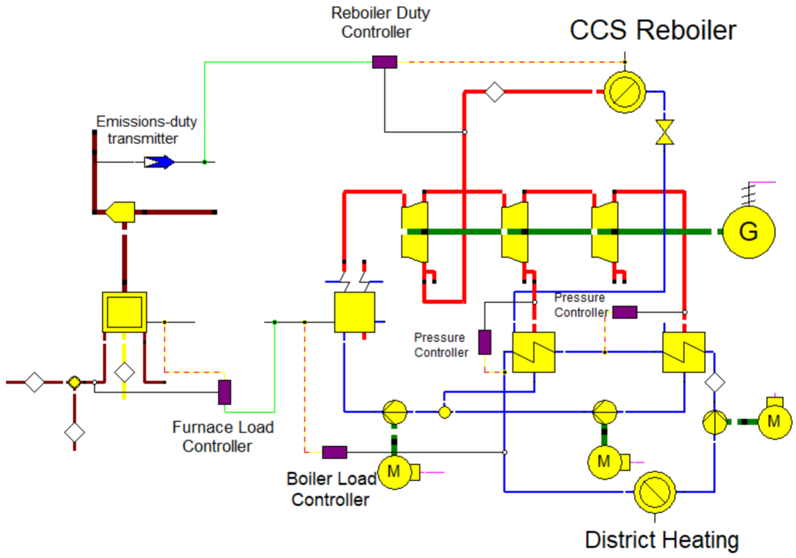

Figure B.9: Ebsilon model with one extraction (Design B) integrated with CCS.

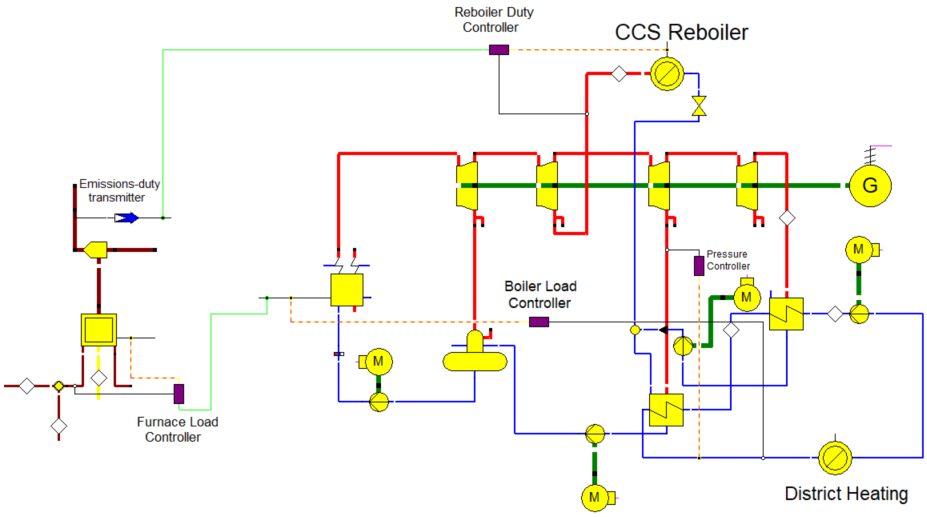

Figure B.10: Ebsilon model with two extractions (Design C) integrated with CCS.

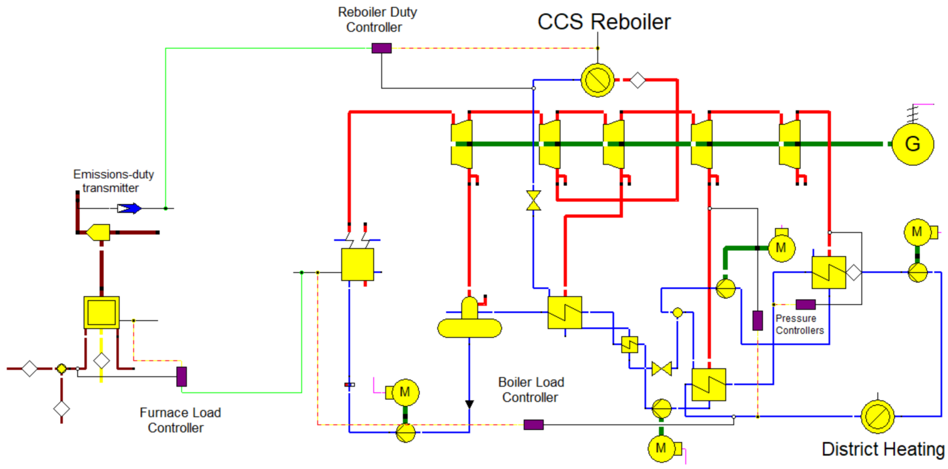

Figure B.11: Ebsilon model with three extractions (Design D) integrated with CCS. For plants with live steam pressures below 40 bar.

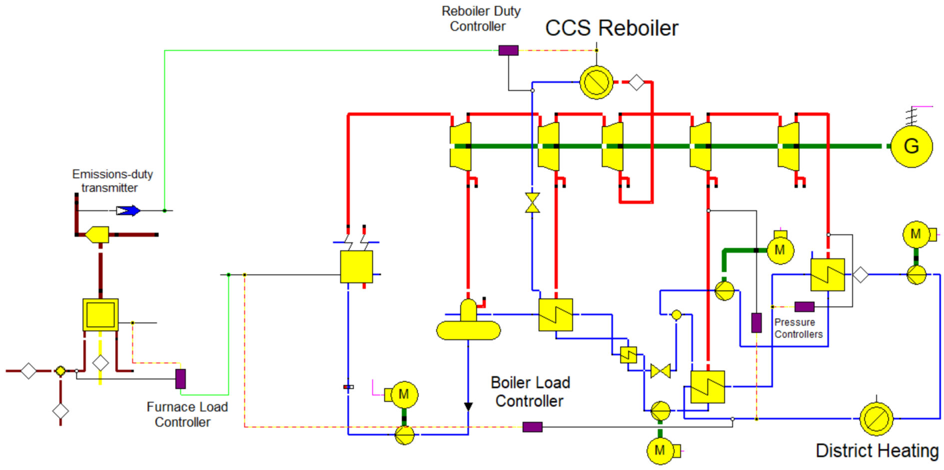

Figure B.12: Ebsilon model with three extractions (Design D) integrated with CCS. For plants with live steam pressure above 40 bar.

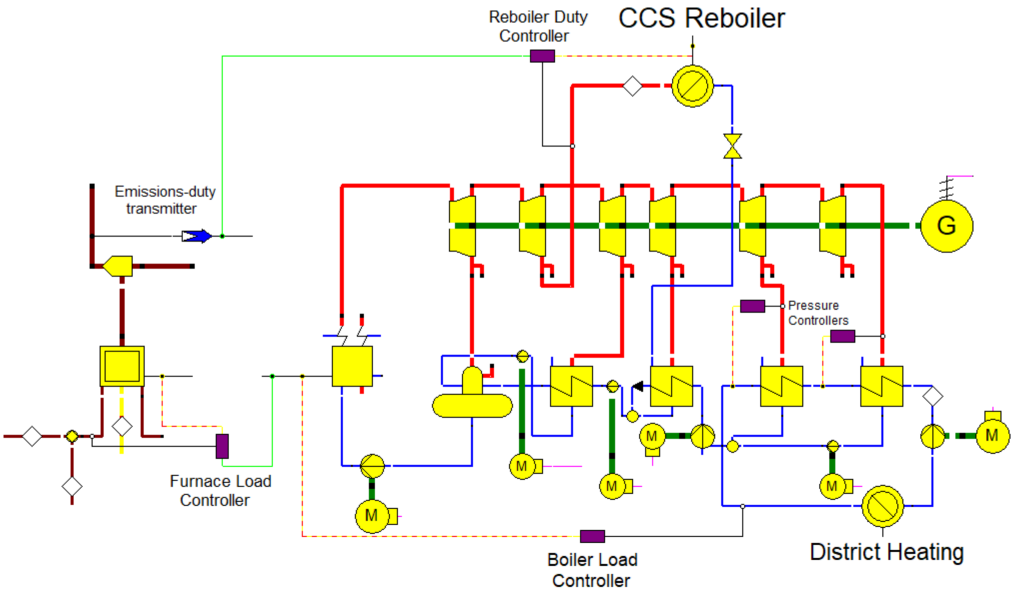

Figure B.13: Ebsilon model with three extractions (Design E) integrated with CCS. For plants with live steam pressure below 45 bar.

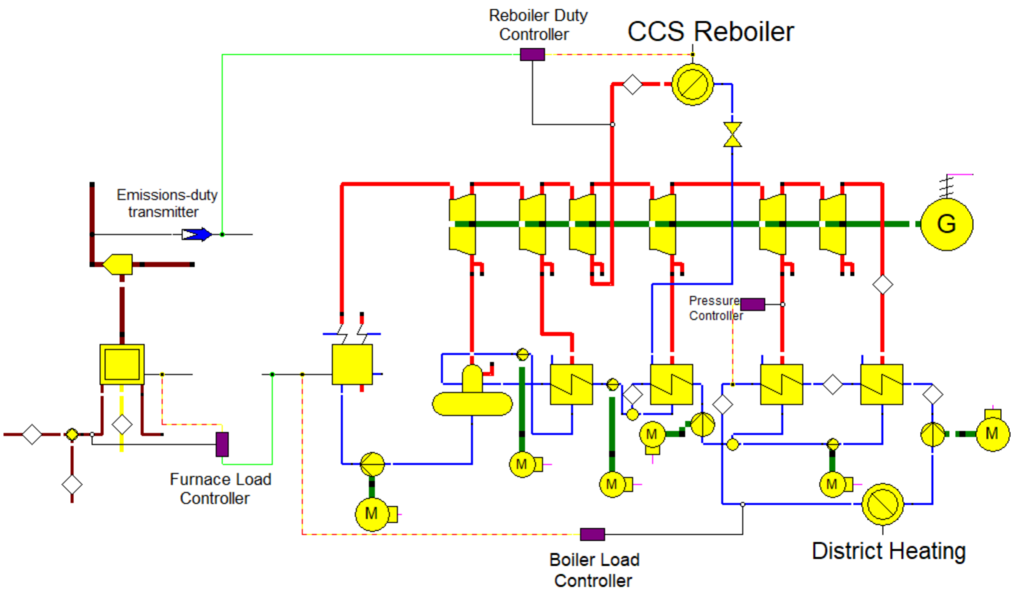

Figure B.14: Ebsilon model with three extractions (Design E) integrated with CCS. For plants with live steam pressure above 45 bar.

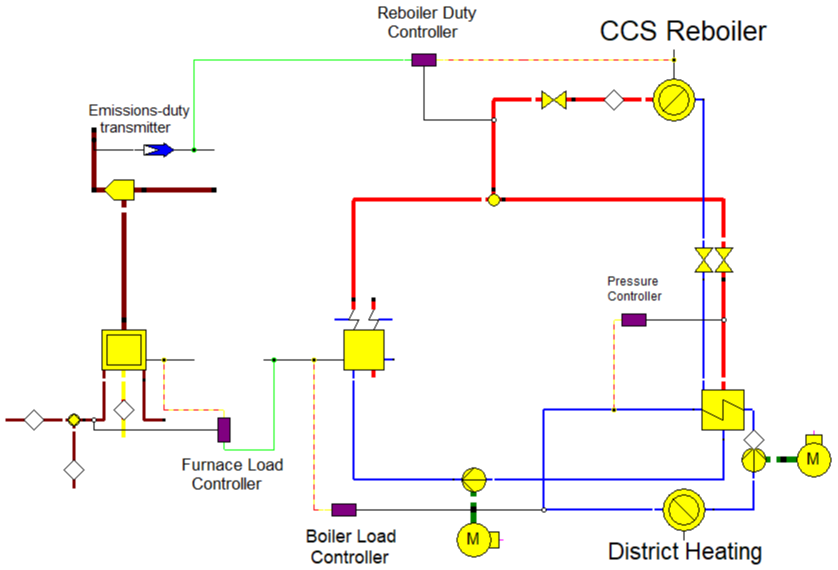

Figure B.15: Ebsilon model for HOB-mode integrated with CCS.