An investment model of a future CO$_2$ free district heating system

Evaluation of the district heating system in Gothenburg in the year 2030

Master's thesis in Sustainable Energy Systems

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Abstract

District heating is an energy efficient way of providing space heating. The city of Gothenburg owns and operates a district heating network and heat plants through the company Göteborg Energi. The city of Gothenburg has set out environmental targets for the city and one of the targets are explored in this thesis. The target states that by 2030 the district heat generation should be free from fossil fuel usage. The goal of this target is in this thesis interpreted as achieving a fossil CO$_2$ free district heat generation. The CO$_2$ emissions from waste and excess heat are outside the system boundary.

Several scenarios for 2030 are studied, each constructed to explore a possible future. An investment model is run for each scenario. This is done in order to evaluate the robustness and cost efficiency of the studied technologies in a future fossil CO$_2$ free district heating system. The investments are evaluated from a socio-economic perspective.

From the scenario studies it is shown that a fossil CO$_2$ free district heating system is achievable. It is also shown that large scale thermal storage can be utilized to lower system costs through load shifting seasonal and daily demand variations. Thermal storage can be used to incorporate large amounts of solar heating panels into the system.

Furthermore it is shown that care must be taken during the planning of the future district heating system in order to avoid overexposure to the price of fuel. Fossil free heating originate from a few primary energy sources. The price of biomass and/or electricity can heavily influence system costs if alternative technologies are not available to counteract high prices. An increased variability in electricity price can be efficiently utilized through use of heat pumps and CHP technologies. These technologies enable district heating to play a role in demand side management of future electricity generation.

Keywords: sustainable district heating, thermal storage, solar heating, modelling, optimization

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Introduction

The district heating network in Gothenburg is owned and operated by Göteborg Energi AB. Göteborg Energi produces district heat mainly using excess heat from waste incineration and oil refineries. The heating demand varies substantially between seasons. More heating is needed during winter compared to during summer. The system is dimensioned for high demand during winter. Even though the largest share of Göteborg Energi's heat production is generated using excess heat sources and renewable fuels, the production during the fall, winter and spring includes heat generated using natural gas and oil. During periods of extreme demand natural gas and oil fuelled plants are started. Low demand during summer require plants to shut down and excess heat to be cooled away in order to avoid overproduction.

Gothenburg City has set local environmental targets that should be achieved by 2030 [1]. One of the targets state that district heating should originate from excess heat sources and facilities fuelled by renewable sources. Emergency heat generation facilities are however allowed to remain fossil fuel fired. For the purposes of this study the goal is interpreted as a district heating generation mix free from fossil CO_2 emissions under normal operations.

In order to achieve this goal, Göteborg Energi needs to phase out their plants running on fossil fuels, such as oil and natural gas. Assuming that the demand for district heating will not decrease over time, there is no possibility to reach this goal without introducing new, fossil-free ways to satisfy future district heating demand.

1.1   Purpose

This master thesis aims to model the district heating production in Gothenburg and to this model, add several investment alternatives that can be used in order to make Göteborg Energi's heat and power generation fossil-free. The effect of implementing these technologies is analyzed from both an investment and operational perspective. The purpose of this analysis is to act as a guide and give insight in the plausible scenario of a fossil-free district heating generation in Gothenburg. The analysis is made from a societal perspective which is represented through using a 3% interest rate and calculating investments using technical lifetimes. This perspective is chosen since the district heating system operator is owned by the municipality which exists to serve its citizens.

1.2 Limitations

The purpose of this master thesis is to evaluate the Gothenburg district heating system from a systems perspective and the detailed specifications for any evaluated technology are not included in this project. The project focuses on how the heat is generated in order to satisfy the demand in the year 2030, hence neither the transition to that system nor the geographical aspect of how the system is constructed, is included in the project. In order to limit the amount of parameters and reduce model optimization time, the model is simplified so that efficiency improvements and retrofit solutions are not investigated.

The model does not include required downtime for the included heat generation or storage technologies. In practice planned shut downs will be required for maintenance and service operations. The effects of unexpected shut downs are not studied in this thesis.

The model operates with perfect foresight and is therefore able to optimize the system with full knowledge of when and how demand and prices vary throughout the year. Operators of actual district heating systems may have some forecast or estimations of these variations include some margin for error in their planning.

The system boundaries are such that they include emissions from any facility whose main purpose is to provide heat to the system but excludes emissions from facilities whose primary purpose is not heat generation. This limitation will result in excess heat sources such as refineries being considered as fossil-free even though the process generating the heat may generate fossil CO_2 emissions.

1.3 Problem statement

1. How can the district heating production system in Gothenburg be composed in the year 2030?

   (a) What production mix could meet the heat demand while complying with the CO_2 target in a cost efficient way?

   (b) What external parameters significantly affect the results and cost effectiveness of the system?

2. How can the systems found in 1a be operated?

   (a) What plant technology properties are important in order to operate the system in a cost efficient way?

2

Background

In this chapter the general characteristics and attributes of the current district heating system are described. The district heating system in operation in Gothenburg is heavily reliant on excess heat for its base load generation. The excess heat is generated in oil refineries and a municipal solid waste incineration plant. Intermediate loads are supplied by heat pumps and various heat only boilers, HOB:s, and combined heat and power, CHP, plants. Peak loads are supplied by smaller gas- and oil-fired heat only boilers. In total the district heating system provides 4 TWh of heat per year to consumers within the area of Gothenburg.

2.1 Current District Heating System

District heating is a way of satisfying heating demand through heat generation at central locations and distributing it through a network of pipes to consumers. A district heating system, DHS, consists of consumers, a distribution network and heat sources. Heat is supplied through the distribution network at temperatures below 100°C, typically 90°C. The relatively low temperatures present in DHS' allow utilisation of excess heat sources at lower temperatures than is possible for electricity generation.

An important aspect of DH networks is that it is possible to store energy within the network for some time. Energy storage is possible through a process known as net charging. The supply temperature of the DH network is increased beyond normal operational temperatures in anticipation of increased demand. The excess heat present in the system can then be used as a buffer, allowing consumer demand to be satisfied while simultaneously allowing smoother ramp ups of heat plants. The main sources of excess heat are a municipal solid waste incineration plant and two oil refineries situated close to the city harbor. In addition to these units the system also consists of several small and medium scale combined heat and power, CHP, and heat only, HOB, plants. The total annual heating demand delivered by the district heating system is approximately 4 TWh [2].

The district heating system currently in operation in Gothenburg consists of a number of generation facilities spread out across the network. The collection of units is very diverse, consisting of large combined cycle gas turbines, waste incineration,

small natural gas fired engines etc. A complete list of heat generation units can be seen in table 2.1 below.

At present the system relies heavily on excess heat from nearby oil refineries, ST1 and Preem, as well as excess heat from the four municipal solid waste incineration CHP units, Renova P1, P4, P5 and P7. Göteborg Energi owns and operates three larger facilities; Rosenlundsverket (total heat capacity of 560 MW), Rya Kraftvärmeverk (total heat capacity of 294 MW) and Sävenäsverket (total heat capacity of 255 MW). Rya Kraftvärmeverk and Sävenäsverket provide the bulk of the self-produced, district heat whilst Rosenlundsverket is mainly used as peak load capacity. In addition to these facilities there is a medium sized heat pump facility; Rya Värmepumpverk, with maximum heat capacity of 160 MW, working as an intermediate production unit. Göteborg Energi also owns and operates a number of smaller facilities, all below 100 MW, that are used as reserves or in case of network failure.

Table 2.1: Existing, currently operational heat generation facilities connected to the district heating grid of Gothenburg. In the column "unit" the internal name of each unit is specified, as used by Göteborg Energi

Facility	Unit	Size [MW]	Primary Fuel
Angered Panncentral			
	HP1	35	Bio oil
	HP2	35	Bio oil
	HP3	35	Bio oil
Björndammens Panncentral			
	HP1	14	Fuel oil*
	HP2	14	Fuel oil*
	EP1	8	Electricity
Högsbo Kraftvärmeverk			
	NM1	5.3	Natural gas
	NM2	5.3	Natural gas
	NM3	5.3	Natural gas
Rosenlundsverket			
	HP2	140	Bunker oil**
	HP3	140	Bunker oil**
	HP4	140	Bunker oil**
	HP5	140	Natural gas
Rya Kraftvärmeverk			
	GT1	98	Natural gas
	GT2	98	Natural gas
	GT3	98	Natural gas
Rya Värmecentral			
	HP6	50	Wood pellets
	HP7	50	Wood pellets
Rya Värmepumpverk			
	VP1	30	Electricity
	VP2	30	Electricity
	VP3	50	Electricity
	VP4	50	Electricity
Sisjön Panncentral			
	CP1	8	Natural gas
	CP2	8	Fuel oil*
	CP3	5	Fuel oil*
Sävenäsverket			
	HP1	80	Natural gas
	HP2	80	Natural gas
	HP3	95	Wood chips
Tynnered Panncentral			
	HP1	10	Fuel oil*
	HP2	10	Fuel oil*
ST1 Raffinaderi			
		85	Excess heat
Preem Raffinaderi			
		60	Excess heat
Renova			
	P1	47	Excess heat
	P4	65	Excess heat
	P5	65	Excess heat
	P7	47	Excess heat

* Eldningsolja 1
** Eldningsolja 5

3

Methodology

The production of district heat is modelled in GAMS (General Algebraic Modeling System) as a mixed integer optimization problem. The model includes existing heat generation units that are assumed to have a sufficiently long technical lifetime long to be operational in year 2030. These units are the gas turbines at Rya, commissioned in 2006, which with a 25 year technical life time (according to [3]) will still be operational. Furthermore the oil refineries as well as the waste incineration units at Renova are assumed to still be in operation. The district heating network can be used as a short term thermal storage. Operationally this is done by increasing the temperature of the network above normal or extracting more heat, lowering temperature more than normal. The amount of energy possible to store in this way is estimated to be 900 MWh. This is calculated by assuming that the largest allowed net temperature deviation is 5 °C (above or below 90°C). The water volume of the district heating network is approximately 77 000 m^3 [4]. The energy that can be stored is calculated using equation 3.1 where $V_{network}$ is the water volume in the network, ΔT the temperature difference in supply and return water, $c_{p,water}$ the specific heat capcity of water and ρ_{water} is the water density.

$$E_{charging} = V_{network} * \Delta T * c_{p,water} * \rho_{water} \tag{3.1}$$

Investment alternatives are added to the model in order to explore possible future scenarios for the year 2030. The scenarios are based on the environmental targets of Gothenburg which state that the goal for 2030 is to have a fossil free district heating system. The city's interpretation of this is that any excess heat utilization may still originate in fossil fuelled processes and emergency peak heating plants may still be fossil fired. But the heat generation facilities for normal use should be fossil free. In this model fossil CO_2 is not allowed to be emitted in any scenarios but one, a scenario used to gauge the cost of the CO_2 target.

The design production curve for a "normal" year, provided by Göteborg Energi, is increased by 20%, it is assumed that the district heating demand will increase by 20% until 2030. The curve describing the heating demand of Gothenburg can be viewed in figure 3.1 below.
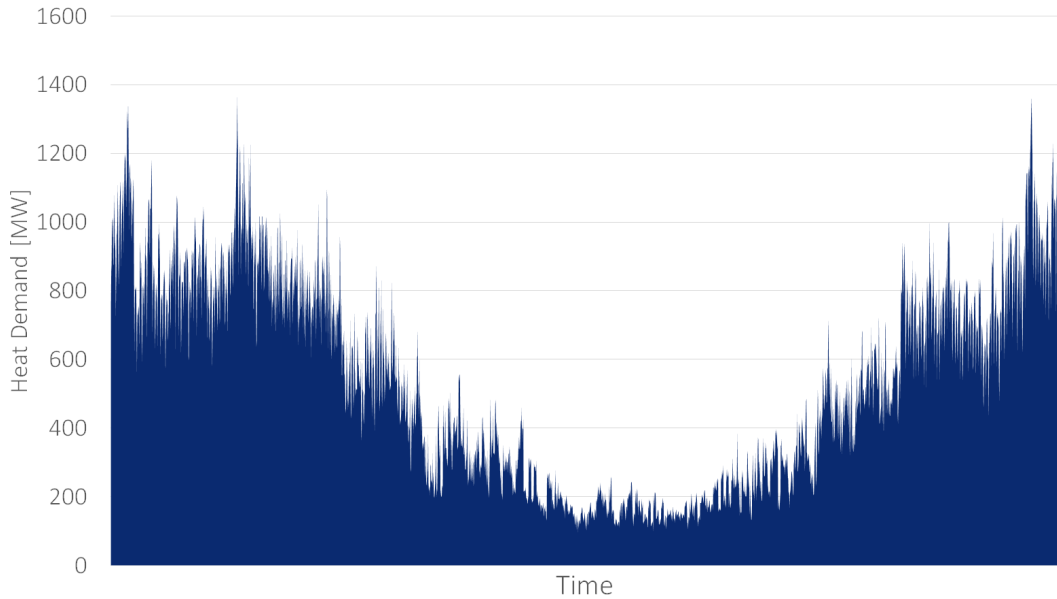
Figure 3.1: The yearly heat demand of Gothenburg in 2030

3.1 Decommissioned plants

The bulk part of the generation units that are present in today's DHS were constructed during the the 1980's. Some of these plants have been redesigned and retrofitted in order to improve efficiency and reduce CO_2-emissions which may improve the technical lifetime. By 2030 these units are over 40 years old and are assumed to have been decommissioned. Exceptions are made for the excess heat sources Renova, St1 and Preem which are assumed to be replaced if they reach the end of their technical lifetimes before 2030 and the relatively newly constructed Rya Kraftvärmeverk that is likely to still be in operation by 2030. Presently existing units that are assumed to still be under operation in the year 2030 are presented in table 3.1.

Table 3.1: Existing heat generation facilities assumed to be in operation in 2030

Facility	Unit	P_{max} [MW]	Primary Fuel
Rya Kraftvärmeverk			
	GT1	98	Natural gas
	GT2	98	Natural gas
	GT3	98	Natural gas
ST1 Raffinaderi			
		85	Excess heat
Preem Raffinaderi			
		60	Excess heat
Renova			
	P1	47	Excess heat
	P4	65	Excess heat
	P5	65	Excess heat
	P7	47	Excess heat

3.2 Investment Alternatives

The investment alternatives include a wide range of technologies so that it represents the many heat generation technologies at hand today. The alternatives also include technologies that may seem economically infeasible in today's conditions as the future scenarios may prove the value of new and innovative generation technologies.

The environmental targets are reflected in the investment alternatives. The alternatives consist of biomass HOB:s or CHP units, heat pumps, additional excess heat from industries, waste incineration, solar heating panels and electric boilers which all can be considered to fulfill the Gothenburg environmental targets. Fossil fuel fired plants are included as investment alternatives in order to be able to gauge the opportunity cost of not using natural gas. Natural gas fired technologies are included in both HOB and CHP configuration.

3.2.1 Investment costs

The investment costs for different technologies are based on published publicly available reports as far as information has been found. Investment costs for CHP units are provided by Elforsk [5]. Data for the HOB units are found in [6]. The data for the storage units is provided from reference project reports by Solites [7] and Rodoverken [8] and the solar heating panel costs are from the Sunstore4 project [9]. All economic properties of the different technologies can be seen in appendix 1. A Capital Recovery Factor, CRF, (see equation 3.7) is calculated in order to evenly distribute the investment cost annually throughout the plant's technical lifetime. The interest rate for this thesis is set to 3%.

3.2.1.1 Linearisation of investment costs for thermal storage

The investment costs for thermal storage units are based on published case reports for thermal storage solutions that have been constructed in Europe. The case reports for each thermal storage technology type; tank (TTES), pit (PTES) and borehole (BTES). These reported costs indicate a nonlinear investment cost function dependent on storage volume. Including nonlinear investment costs of this type requires numerous integer operations in order to solve the optimization problem. Integer operations increase the computational time for solving the model significantly. In order to reduce computation times, the cost functions of the thermal storage technologies are approximated with a linear equation. This approximation yields investment cost curves of the type:

$$IC_{storage} = C_E * A \tag{3.2}$$

Where $IC_{storage}$ is the total investment cost for a storage of capacity C_E and specific investment cost A. With this implementation the model can be constructed using fewer integer operations than would otherwise be necessary. The total investment cost functions used are presented in table 3.2 as a function of the maximum stored energy.

Table 3.2: Total investment cost functions for the three thermal storage types

Technology	Total cost function [SEK]
TTES	$IC_{storage} = C_E * 14159$
PTES	$IC_{storage} = C_E * 3694$
BTES	$IC_{storage} = C_E * 5986$

3.2.2 Investment limitations

Some of the investment alternatives are limited so that the model can not invest in infinite numbers or size. For solar heating panel and thermal storage, the limitations are set to be slightly larger than, to our knowledge, the largest existing solar heating plant and thermal storage in the world. Solar heating investments are in this scenario limited to 100 000 m^2. Thermal storage investments are limited to 3000 MWh, 6000 MWh and 2000 MWh for TTES, PTES and BTES respectively. The heat pumps are limited to have a total maximum power output 160 MW which is the maximum power output of the today existing sewage heat pumps. The amount of sewage water is, in this thesis, not expected to increase hence the same capacity.

3.2.3 Technical properties

The technical properties are in as far as information is given taken from the reports where the respective investment costs are presented. Start up times for combustion technologies are taken from the grid codes specified for the Danish electrical grid, see [10], which is assumed to be similar to Swedish grid codes. Solar heating panels are assumed to have an efficiency from horizontal irradiation to heat of 40% [9]. Solar radiation curves for Gothenburg are based on a calculated hourly average irradiation from the years 1991 to 2000 provided by the Swedish weather service SMHI [11]. This set of years contains three leap years. These are combined as an average with the other years by excluding 31st of December from the leap years, thus creating 10 years with 8760 hours each. In the sensitivity analysis it is evaluated how using actual irradiation curves might affect the dispatch of the modeled scenarios. The solar irradiation curve can be viewed in appendix 2.

The electricity prices are projected for the year 2030 assuming that there are no changes in the Swedish energy policy, that EU electricity demand stabilizes and that all the member states of the EU are fulfilling the National Renewable Energy Action Plan, NREAP, that they have committed themselves to achieve by 2020. The electricity demand is assumed to stabilize due to continuous energy efficiency measures in the EU. The NREAP includes targets on renewable energy share on

a national level to ensure that the EU as a whole reaches the 2020 target for the share of renewable energy. The electricity prices are modelled by Lisa Göransson [12] under these conditions and presented as the market clearing price for every third hour of the year. The electricity buying price is set to be the sum of the market clearing price, the transmission cost of 270 SEK/MWh [13] and the Swedish energy tax of 294 SEK/MWh [14]. The market clearing price can be viewed in appendix 3. Electricity consumed in the DHS is in this thesis assumed to be CO_2 neutral.

3.3 Description of the optimization model

The main parts of the optimization model are described in the subsections below. The model goal is to minimise the total yearly system cost, while obeying all constraints placed upon it. The constraints are divided in to logical, technical and technology specific subsections and presented below. The model is run with a 3-hour time resolution. This decreases computational time as compared with using a 1-hour resolution and has not been observed to affect the results significantly.

3.3.1 Objective function

The objective function is the total system cost. It includes total running costs, fuel costs, overhead and maintenance costs as well as annualized investment costs where applicable. The mathematical notation of this objective function is:

$$System\_cost = \sum_t \sum_i VC_{i,t} + FC_i \tag{3.3}$$

3.3.1.1 Variable Cost

$VC_{i,t}$ is the total variable costs for technology i in time step t. This variable cost is calculated as:

$$VC_{i,t} = Time\_scale * \left(\frac{SC_{fuel}}{\eta_i} + VOM_i - SC_{electricity,t} * \alpha_i \right) + UST_{i,t} * STUPC_{i,t} \tag{3.4}$$

In this equation, $Time\_scale$ is a scale factor defined as:

$$Time\_scale = \frac{Hours\ in\ a\ year}{Time\ steps\ in\ a\ year} = \frac{8760}{2920} = 3 \tag{3.5}$$

SC_{fuel} is the specific cost per MWh of the fuel used by technology i and η_i is the district heat generation efficiency of that technology. VOM_i is the specific overhead

& maintenence costs of the technology. For CHP plants, $\alpha > 0$, the last factor represents the generated electricity which is sold at the price $SC_{electricity,t}$. In the last multiplication ($UST_{i,t} * STUPC_{i,t}$) $UST_{i,t}$ is an integer variable which indicates how many plants, of type i, initiate a start up sequence in time step t. This is then multiplied with the unit start up cost, $STUPC_{i,t}$. This cost is calculated as if the plant was running at P_{min} during the entire start up time, see [10], without producing any usable heat or electricity.

3.3.1.2   Fixed Cost

The fixed cost, FC_i, present in the system cost function is defined as:

$$FC_i = C_i * (FOM_i + IC_i * CRF_i) \tag{3.6}$$

In this equation C_i is the heat generating capacity of technology i. This is multiplied with the fixed O&M costs, defined as SEK per MW capacity. It is also multiplied with the specific investment cost, IC_i, of technology i and the capital recovery factor, CRF_i, specific for technology i which is defined as:

$$CRF = \frac{r(1+r)^n}{(1+r)^n - 1} \tag{3.7}$$

In this equation r is the interest rate employed for the investment, in this case 3%, and n is the number of annuities to be payed, that is the technical life time of the new unit.

3.3.2   Constraints

The objective function is subject to a number of constraints. These constraints are implemented for the model in order to properly reflect the way the units and the district heating system is operated. The constraints used in the model are presented below, beginning with the system balance constraint.

3.3.2.1   Balance

The balance constraint ensures that heat generation and demand are equal in each time step. In mathematical terms this constraint is represented as:

$$\sum_i x_{i,t} + s_{i,t} + q_{i,t} = heat_{Demand,t} \ \forall t \tag{3.8}$$

$x_{i,t}$ is the production of plant type i at time step t, $s_{i,t}$ the production from solar heating and $q_{i,t}$ is the heat flow from storage type i in the same time step. Heat generation subtracted by any heat stored must, for all time steps t, equal the heat

demand. The heat demand as supplied is assumed to increase by 20% until 2030. The design heat demand [2], which includes 8784 time steps is reduced to 2920 values by removing the first 24 values and extracting every third value. This extracted heat demand is then increased by 20% to reflect the assumed increase in district heating demand.

3.3.2.2 Technical constraints

Technical constraints influence the way the heat generation units are run, an obvious example of such technical constraints is that a plant type cannot produce above its maximum capacity P_{max}. This constraint is mathematically represented as:

$$x_{i,t} \leq N_{i,t} * P_{max,i} \tag{3.9}$$

$N_{i,t}$ is an integer variable that indicates how many of the plant type i that are running at time step t. There exists a minimum level below which it is not feasible to generate district heat, this limit is denoted as P_{min} and the constraint is expressed as:

$$x_{i,t} \geq N_{i,t} * P_{min,i} \tag{3.10}$$

3.3.2.3 Storage related constraints

Storage units are operated differently to conventional generation units. The energy stored in storage type i at time step t is denoted $E_{i,t}$. The storage unit is then limited by the invested capacity, $C_{E,i}$. The storage constraints are based upon those employed by Akkaya and Romanchenko [15]. The mathematical formulation of this constraint is written as follows:

$$E_{i,t} \leq C_{E,i} \tag{3.11}$$

The charge and discharge of a storage unit is limited. The energy flow, $q_{i,t}$ of tank and pit type energy storage is limited by the storage size. Borehole thermal storage is limited by the size of the heat pump that is installed which is why it's energy flow is not limited by the constraint below. The energy flow $q_{i,t}$ is defined as positive while energy is flowing from the storage unit and negative as energy is flowing into the unit. The mathematical representations of these constraints are then:

$$q_{i,t} \leq C_{storage,i} * P_{discharge,i} \tag{3.12}$$

$$q_{i,t} \geq C_{storage,i} * P_{charge,i} \tag{3.13}$$

As $q_{i,t}$ is positive while the storage unit is discharging and negative while it is charging, $P_{discharge,i}$ is also positive and $P_{charge,i}$ is negative. These two factors are

scale factors dependent on the invested energy storage capacity, $C_{storage,i}$. For tank and pit thermal storage $P_{discharge,i}$ is set to 0.05 and $P_{charge,i}$ to -0.05. This is in line with examined literature [15] and communications [16].

The final constraint on the storage units is their state constraint. This constraint ensures conservation of energy, energy stored in a unit i at time step t is equal to the energy stored in the unit previous time step and any energy that has flowed into or out of the unit. A loss factor, LF_i, is also included to reflect the losses that occur while the energy is being stored.

$$E_{i,t} = E_{i,t-1} * (1 - LF_i) - q_{i,t-1} \tag{3.14}$$

3.3.2.4   Solar heating related constraints

Solar heating panels only produce district heating in relation to the solar irradiation. The production can't be controlled in the sense that it can be turned on and off as the network operator desires, if the sun shines, the solar heating panels produce district heating. This constraint is written as:

$$s_{i,t} = \eta_i * C_{i,t} * solar\_curve(t) \tag{3.15}$$

where η_i is the average efficiency, 40%, of a solar heating panel which is assumed to be applicable during the entire year according to [9], the *solar_curve* is the solar irradiation for every hour during an average year in Gothenburg, based on [11], and $C_{i,t}$ represents the area of solar collectors that are installed.

3.3.2.5   Logical Constraints

The model requires a number of logical constraints for proper operations, these are based on the Integer Programming approach employed in [17]. These constraints are presented in brief below. The constraint 3.16 ensures that one or several units cannot be running unless they were running during the previous timestep or if they just finished their start up sequence, started $STUP_i$ time steps earlier.

$$N_{i,t} \le N_{i,t-1} + UST_{i,t-STUP} \tag{3.16}$$

All units that the model decides to invest in of the same plant type, n_i where n is the number of invested units, cannot be running in the same time step as they initiate a start up sequence. This constraint is mathematically formulated as:

$$N_{i,t} + UST_{i,t} \le \frac{C_i}{P_{max,i}} \tag{3.17}$$

In this equation C_i is the installed capacity of plant technology i.

3.3.2.6 Storage investment constraints

The investments in storage are made using a linear approximation of existing storages. The investment cost constraint can be seen below

$$IC_{storage,i} = CRF_i * C_{E,i} * IC_{specific,i} \qquad (3.18)$$

In this equation $C_{E,i}$ represents the energy storage capacity of storage i and $IC_{specific,i}$ is the specific investment cost for a storage of type i.

3.4 Scenarios

The scenarios studied in this project each represent a possible future the district heating system could face. The model is constrained in different ways in each scenario in order to explore which investments are most cost efficient and how they affect operational strategies. The first scenario, in which all fossil heat generation is replaced, is referred to as a reference scenario. In the scenario presented in 3.4.3 a future without a CO_2 limit is explored. This is partly made in order to be able to gauge the opportunity cost of not using natural gas in the district heating system. In the other scenarios it is assumed that the environmental goal is achieved and that no fossil CO_2 is emitted. Heat generated in the oil refineries and the waste incinerators are assumed to not emit any CO_2 attributable to the district heating system. These scenarios vary in what excess heat sources are available, how large investments in solar and storage technologies are allowed and what policy systems are included. All scenarios are presented below.

3.4.1 Reference scenario, Fossil heat generation is replaced

In this scenario it is assumed that all aged and/or fossil heat generation is replaced by 2030 in order to achieve the CO_2 goal. As the city's system boundaries stated in the Climate Programme allow for excess heat utilization, Renova and the oil refineries are assumed to still be operational and supplying heat with no associated CO_2 emissions. The constraints in this reference scenario are also present in the others if nothing to the contrary is stated.

3.4.2 Storage is not an option

Seasonal storage and thermal storage in general is an interesting technology that enables load shifting. Storage is not presently utilized but it is hypothesized that storage may be cost efficient. Constructing storage units require several land-use and environmental related permits issued by governmental agencies and is therefore a process not entirely controlled by Gothenburg and Göteborg Energi. The effects of not receiving necessary permits to construct large scale thermal storage is therefore important to investigate.

In this scenario investments in storage are prohibited in order to be able to gauge any cost and operational benefits of utilizing thermal storage to a larger extent. The result from this scenario can also be used to show how a conventional district heating system can be constructed and operated in the year 2030.

3.4.3   No CO_2 target

In this scenario there are no limitations placed upon CO_2 emissions. Operation of the gas turbines at Rya and investments in new fossil fired plants are allowed. This scenario exists in order to explore the opportunity cost of not using natural gas as an option. The system cost of this scenario in comparison with those where the CO_2 goal is reached can give insights into at what cost the goal can be achieved.

3.4.4   The oil refineries are shut down

Oil refineries in the port of Gothenburg supply a large share of the total district heat demand. The Gothenburg Environmental administration states that they assume that the refineries will still be in operation in the year 2030 and that if they are shut down this will not happen over night so that the system has time to adapt [18]. The refineries are operated by ST1 and Preem which are under market pressures that can change rapidly. Increased and more ambitious climate targets could also decrease the incentives for oil refinery operations in Gothenburg. These are two factors influencing refinery operations beyond Gothenburg's or Göteborg Energi's control which is why this scenario is worth investigating.

3.4.5   All excess heat sources are replaced

The system boundaries governing the CO_2 goal may be slightly expanded in order to find a more ambitious goal. In this scenario the system boundary is expanded to include the emissions from Renova and the oil refineries. Due to these expanded boundaries investing in a new pipeline to the Steungsund chemical cluster is not permitted either. A CO_2 neutral district heat system can thus not utilize these excess heat sources. New investments have to be made in renewable base load capacities. This scenario explores how a district heating system that is not as dependent on the indirect utilization of fossil resources might look and be operated.

3.4.6   Include green certificates

The green certificate policy system is set to expire at the latest in 2035 [19]. The policy system has common goals which are to be achieved by 2020[20]. After 2020 there exists an uncertainty about how the system will be utilized or if it will be retired. In this scenario it is assumed that the system is still in effect during 2030 at a quota level corresponding with 200 SEK per MWh produced in 2012's monetary

value[21], this corresponds to 204 SEK per MWh in 2015's monetary value. The quota of green certificates in the production mix is set to be 7,6% [22] in the year 2030 which yields an additional cost of buying electricity of 16 SEK/MWh. This policy system greatly affects the competitiveness of biomass fired CHP plants relative to biomass and electric HOBs, the former being favoured by the policy system. The scheme is added as an additional income for biomass-fired CHP units which is payed for by the electricity consuming units such as heat pumps, electric boilers and pumps.

3.4.7   Unlimited solar and storage investments

The investments in solar heating and thermal storage are constrained in all scenarios but this one. In this scenario the model is freely allowed to invest in as much solar heating and thermal storage as is cost efficient. These two technologies have constraints placed upon them that are uncertain.

3.5   Sensitivity analysis

In the sensitivity analysis the optimized system setups from the scenarios are locked in. It is explored how vulnerable these systems are to varying external factors such as biomass price, electricity prices and assumptions made in this thesis. This analysis is made both to gauge the robustness of the systems suggested in this thesis and to explore vulnerabilities within their operation. The variables for which analysis is presented in this thesis are: biomass price, electricity price, thermal storage loss factors and solar irradiation. The respective sensitivity analysis are presented in the sections below.

3.5.1   Price of biomass

A district heating system without any fossil CO_2 emissions is dependent on either intermittent energy sources or on renewable sources such as biomass. In this sensitivity analysis the dependence and vulnerability to the price of biomass is explored. The biomass prices is increased by 50% from the projected level utilized in the scenario runs.

3.5.2   Electricity price

The electricity prices employed in the general scenario runs are from a scenario in which the Swedish energy system still utilizes nuclear power. Developments around the world and in Sweden indicate that this is not necessarily the case. In this sensitivity analysis the price projections are instead based on a future scenario with increased price variability where Swedish nuclear power has been decommissioned

and replaced with increased wind power capacities. This electricity price can be viewed in appendix 4.

3.5.3   Solar irradiation

The solar irradiation curves employed in the scenario runs are based on an hourly average during the years 1991 until 2000. Utilizing average irradiation data removes important aspects to solar irradiation, it decreases variability and evens out great variations. In order to gauge how this affects the operation of the different systems an analysis is made by using actual solar irradiation curves for 1994 and 1998. The shape of these irradiation curves is maintained but the total irradiated energy is set to equal that of the average curve. In this way the system receives the same amount of solar irradiation but with retained variability.

3.5.4   Loss factors in thermal storage

The loss factors in the thermal storage technologies utilized in this thesis are the result of complex interactions within the storage and between the storage and its surroundings. Literature describing these relationships in terms translatable to the developed model is sparse. Assumptions regarding the loss factors in the thermal storage technologies are thus uncertain. In this sensitivity analysis the loss factors are increased by a magnitude of ten in order to gauge the sensitivity of the system to this variable.

3.5.5   Increased solar panel investment cost

The investment costs of solar panels are based on approximations from existing plants. The investment cost is dependent on land value and ground leveling cost which differs significantly depending on location. The land value in Gothenburg is believed to be higher than at the location where the studied plants are situated. It is therefore interesting to study how price variations in the cost of solar panels impact the models willingness to invest. In this sensitivity analysis the cost of solar panels are increased by 10%. The optimization model is then rerun for the reference scenario to investigate how changing the cost influences the investment decisions.

4

Results

The results of the technology study, scenario studies and sensitivity analysis are presented below.

4.1 Technology study

The technology study identified a number of potential investment alternatives. Potential technologies identified include gas and biomass fired HOB:s and CHP units, heat pumps and increased excess heat. The heat pumps are limited to a maximum of 160 MW. This corresponds to the amount of heat which is currently extracted by existing heat pumps from the sewage. Coal fired technologies are not included in the study. In Sweden there are currently four companies operating coal plants, all of which are working to replace the plants with renewable alternatives [23]. Oil usage is decreasing, in 2013 oil usage for steam and hot water production was 2.75% of total energy usage [24] hence it is not included.

The technology study also includes technologies that may seem economically infeasible and not fully developed today but may have unexpected effects on how the system is managed. These technologies may also be associated with other values than money, such as political and societal values, which make them interesting to include in the technology study. Two such technologies have been identified, solar heating panels and seasonal thermal storage. For further information about the technologies selected in the technology study and the properties associated to them, see appendix 5.

4.2 Scenario study

The scenarios studied are meant to represent several possible futures the district heating system might face. The scenario results indicate that systems with access to excess heat sources tend to invest in intermediate load generation such as heat pumps and biomass-fired HOB, as shown in production curves a,b,c,d and g in figure 4.1 or in combination with green certifitcates, biomass-fired CHP units, shown in production curve f in figure 4.1. If the system does not have access to excess heat, investments are made in biomass-fired CHP units and heat pumps to supply the base load which can be seen in production curve e in figure 4.1. With a socioeconomic discount rate of 3% solar heating panels become very cost efficient. This is a technology with very high investment and low running costs. Technologies of this kind are favoured by a low discount rate. In all scenarios where it is allowed, investments in storage technologies are made. Tank and Pit thermal storage technologies with low running costs are especially favourable. Borehole thermal storage, which requires investments in heat pumps are not as profitable as it is exposed to electricity prices. With this in mind it is more cost efficient to invest in more production technologies instead of load shifting with a borehole thermal storage.

In table 4.1 a comparison of the system, running and constant costs of the different scenarios is presented. The scenarios with less or no excess heat has higher running costs than the other as they do not that have access to inexpensive heat generation. The green certificates scenario has lower running cost than the rest as the use of biomass CHP is subsidised. The constant cost of the no excess heat scenario is much higher than the others as it has to invest in a completely new system. The no target scenario has a lower constant cost as it is allowed to operate Rya KVV and therefore doesn't have to invest in as much new capacity.

Table 4.1: Costs associated to the different scenarios. The running cost includes the variable operation and maintenance cost and the fuel cost i.e. the cost of operating the system. The constant cost is the sum of fixed costs and annuities on the investments made. The system cost is the total cost of owning and operating the system.

Scenario	Running cost [MSEK]	Constant Cost [MSEK]	System Cost [MSEK]
Reference	939	429	1 368
No storage	907	539	1 446
No target	945	313	1 258
No oil refineries	1 068	509	1 577
No excess heat	1 305	728	2 033
Green Certificates	770	483	1 253
Unlimited	805	489	1 294

(a) All fossil heat replaced

(b) No storage

(c) No CO$_2$ target

(d) No oil refineries

(e) No excess heat

(f) Green certificates

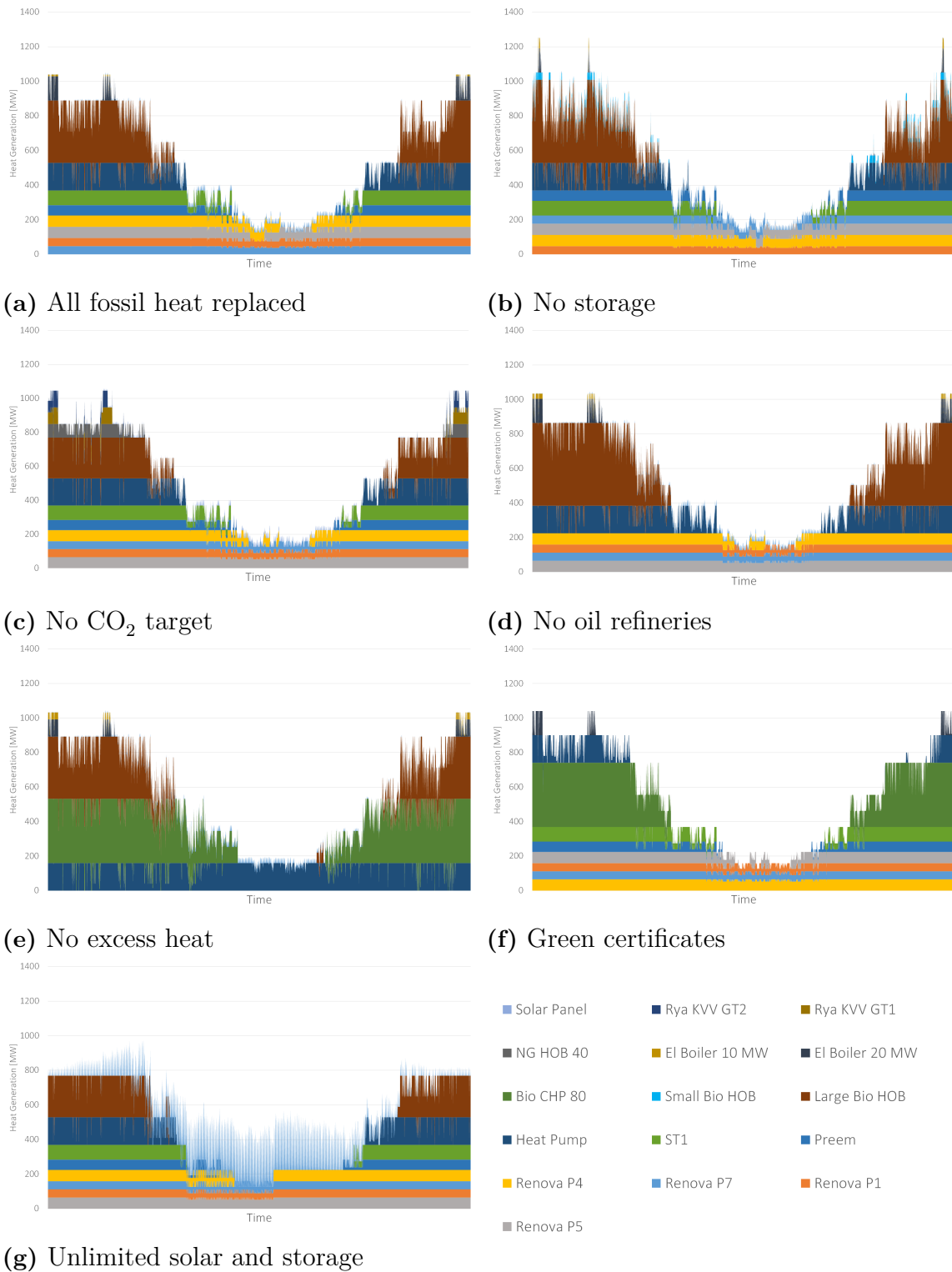**(g)** Unlimited solar and storage

Figure 4.1: Annual production for all studied scenarios where heat generation is presented on the x-axis in the unit MW and time is on the y-axis.

4.2.1 Reference scenario, Fossil heat generation is replaced

The reference scenario of replacing all fossil heat generation results in a system cost of 1 368 MSEK per year. The model invests in large thermal tank and pit storage, heat pumps, electric boilers and large biomass HOB's. The investments made in this scenario are presented in table 4.2.

Table 4.2: Production mix in the reference scenario. In the "Number of units" column, the number of units invested in and operated, are presented. This means that even though Rya KVV is still present in the system, it is not presented here as it is not operating

Plant Technology	Size	Number of units	Primary Fuel
ST1 Refinery	85 MW	1*	Excess Heat
Preem Refinery	60 MW	1*	Excess Heat
Renova P1	47 MW	1*	Excess Heat
Renova P4	65 MW	1*	Excess Heat
Renova P5	65 MW	1*	Excess Heat
Renova P7	47 MW	1*	Excess Heat
Heat Pump	20 MW	8	Electricity
Large Biomass HOB	120 MW	3	Biomass
Solar Heating Panels	40 MW**	100 000 m^2	Solar radiation
TTES	± 150 MW***	3000 MWh	District heat
PTES	± 300 MW***	6000 MWh	District heat
Electric Boiler	10 MW	1	Electricity
Electric Boiler	20 MW	7	Electricity

* Already existing sources of heat
** Peak capacity for 100 000 m^2 of solar panels
*** Peak charge and discharge rate for the the invested storage capacity

The annual production can be seen in figure 4.2. From figure 4.2 one can see that the model utilizes Renova's waste incineration plants extensively as base load during the entire year. All of Renovas furnaces have over 7900 full load hours. One of Renovas larger furnaces, P5, is turned off in the end of June and turned back on in the middle of August. This is due to decreased demand and fully utilized thermal storage. During the entire low demand period, during which only the Renova furnaces and the solar heating is used, the furnaces at Renova are utilized to enable full solar production and balancing demand and energy storage. The oil refineries are below Renova in the merit order and are turned on first in the beginning of September. During the initial period, while demand is still building, the furnaces at Renova occasionally decrease production in order to keep the oil refinery excess heat generation running. The heat production in the oil refineries are then turned on until the beginning of June. In total the refineries are utilized for 6019 and 5990 full load hours for Preem and ST1 respectively. Below the refineries in the merit order are the new heat pumps, these are utilized for 4320 full load hours and are turned on in the end of September. The heat pumps are utilized at full capacity while electricity is inexpensive in order to buffer and enable being turned off while electricity is expensive. To further enable this behavior the large biomass HOB's, below the heat pumps in the merit order, are utilized to balance production, storage

and demand. The biomass HOB's are turned on in the end of October and remain on until the end of April. For extreme peaks which are not compensated for by thermal storage, the electric boilers are utilized, in total they are used for 480 full load hours. The electric boilers are utilized during high demand periods and the model is optimized in such a way that the thermal storage compensates for all high demand periods that occur during high electricity prices, thus lowering the cost for peak electric capacity usage.
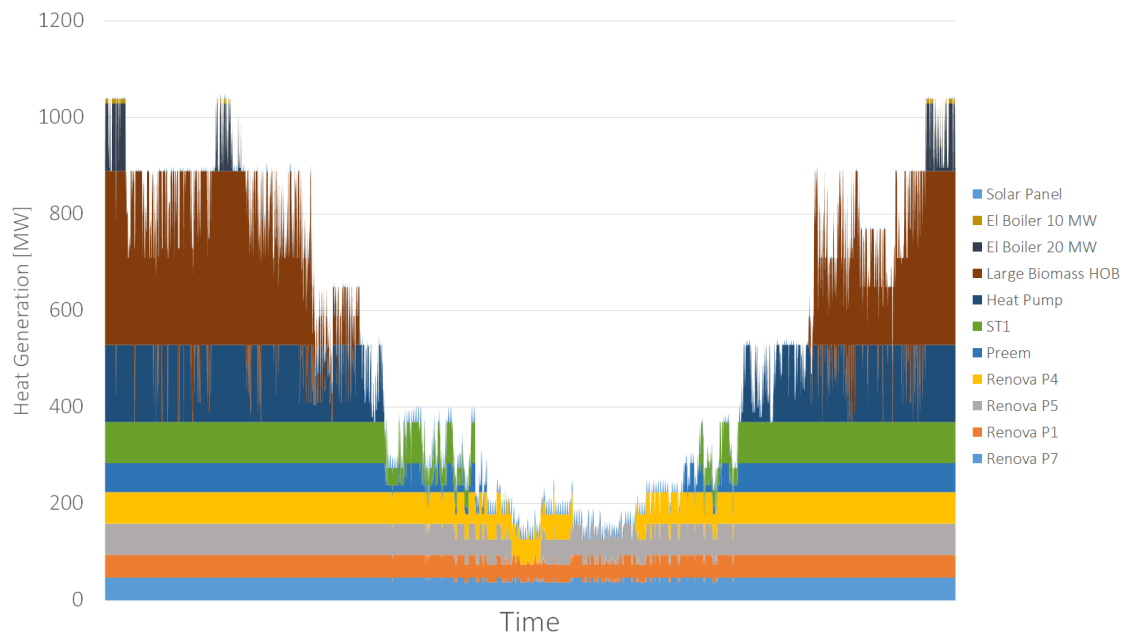
Figure 4.2: The production of a typical year with the system modelled under the condition that all fossil heat generation is replaced

4.2.2 Storage is not an option

The total system cost for the system when investments in thermal storage are disallowed becomes 1 446 MSEK per year. This is higher than the reference case as the system is further constrained. The investments that the model makes, shown in table 4.3, are similar to the investments made in the reference case with the difference that it invests in more biomass-fired HOBs. This is because with no storage the system has to invest in more generation capacity to cover peak demands. Without large scale energy storage there is also less incentive in investing in solar heating panels. The model invests in 94 510 m^2 of panels, below the cap of 100 000 m^2.

Table 4.3: Production mix in the scenario where no storage is present. In the "Number of units" column, the number of units invested in and operated, are presented. This means that even though Rya KVV is still present in the system, it is not presented here as it is not operating

Plant Technology	Size	Number of units	Primary Fuel
ST1 Refinery	85 MW	1*	Excess Heat
Preem Refinery	60 MW	1*	Excess Heat
Renova P1	47 MW	1*	Excess Heat
Renova P4	65 MW	1*	Excess Heat
Renova P5	65 MW	1*	Excess Heat
Renova P7	47 MW	1*	Excess Heat
Heat Pump	20 MW	8	Electricity
Small Biomass HOB	21 MW	2	Biomass
Large Biomass HOB	120 MW	4	Biomass
Solar Heating Panels	38 MW**	94 510 m^2	Solar radiation
Electric Boiler	10 MW	6	Electricity
Electric Boiler	20 MW	7	Electricity

* Already existing sources of heat
** Peak capacity for 94 510 m^2 of solar panels

When considering how the district heating network is managed without thermal storage, shown in figure 4.3, the most obvious differences compared to the reference case are the higher peak generation and the fluctuating heat generation.
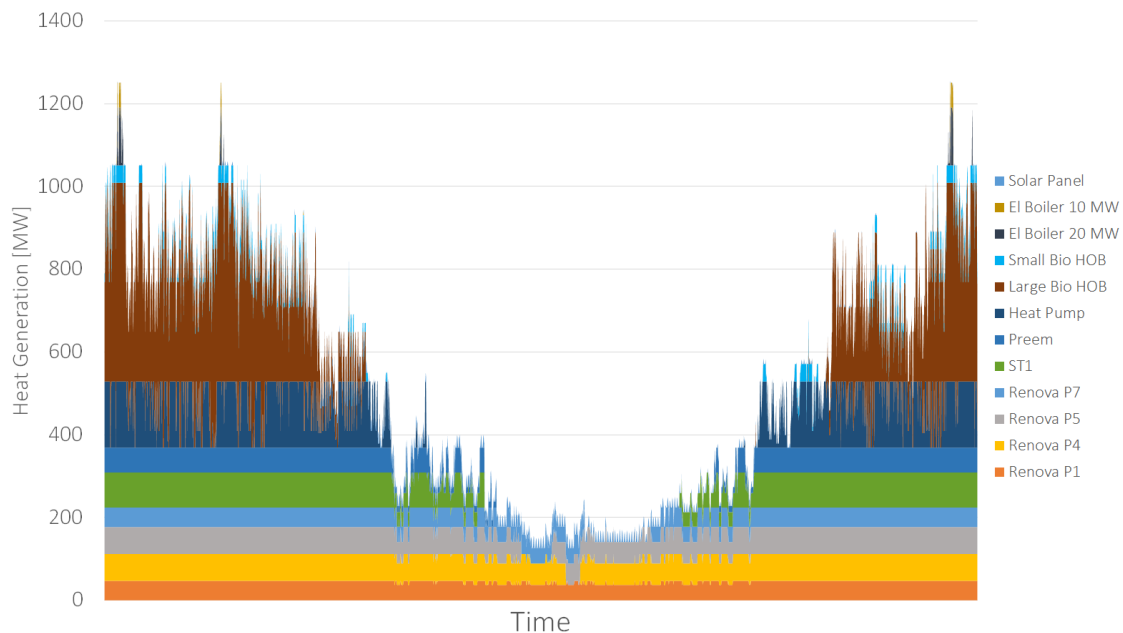

Figure 4.3: The production of a typical year with the system modelled in the no storage scenario

The Renova furnaces and oil refineries are run as base production. The Renova furnaces are run largely throughout the year with the exception of shutting down

one furnace during a brief period during the summer. The refineries are turned on in September and then run, without turning off, until May. In the begining of October demand exceeds the possible production from Renova, the refineries and the solar panels hence the heat pumps are turned on. During October the small biomass HOB's are occasionally turned on as demand surpasses the possible production even with the heat pumps on. Once demand has increased further the large biomass HOB's are turned on and fulfill a balancing role, enabling the heat pumps to be shut off during high electricity prices. Electric HOB:s are utilized for peak demand. In total the model invests in 200 MW of electric HOB:s to deal with the highest demands. Without any investments in thermal storage, intermediate and peak load capacities are forced to shift production more rapidly and to a larger extent than if production can be buffered.

4.2.3 No CO_2 target

The total system cost in the case where the model is not CO_2 constrained is 1 258 MSEK per year. In comparison with the reference case this is 109 MSEK lower, which can be viewed as the yearly cost of not using natural gas. If Rya is removed from this scenario the total system cost is instead only 96 MSEK lower than the reference scenario. Including Rya thus enables avoiding 13 MSEK in investments which would be made in more tank storage and 40 MW of electric boilers. In this thesis it is assumed that a combined cycle gas turbine has a technical lifetime of 25 years which means in that Rya is scheduled for decommissioning in 2031. It is therefore interesting to investigate what other units the model would invest in without Rya KVV in the system. The investments made in this scenario, shown in table 4.4, are solar heating panels and heat pumps as in the other scenarios but it differs from the others as it partially invests in natural gas-fired HOBs instead of biomass-fired HOBs. One can also see that the amount of heat storage in TTES is less than in the other scenarios. This can be explained by the fact that the natural gas-fired HOBs are cheaper to run as compared with electric HOB's during high electricity prices. With this in mind, storing heat for exploitation during peak demand is not as valuable.

Table 4.4: Production mix in the scenario without a CO_2 limitation. In the "Number of units" column, the number of units invested in and operated, are presented.

Plant Technology	Size	Number of units	Primary Fuel
ST1 Refinery	85 MW	1*	Excess Heat
Preem Refinery	60 MW	1*	Excess Heat
Renova P1	47 MW	1*	Excess Heat
Renova P4	65 MW	1*	Excess Heat
Renova P5	65 MW	1*	Excess Heat
Renova P7	47 MW	1*	Excess Heat
Rya KVV	98 MW	2*	Natural Gas
Heat Pump	20 MW	8	Electricity
Large Biomass HOB	120 MW	2	Biomass
Medium NG HOB	40 MW	2	Natural Gas
Solar Heating Panels	40 MW**	100 000 m^2	Solar radiation
TTES	±95 MW***	1895 MWh	District heat
PTES	±300 MW***	6000 MWh	District heat

* Already existing sources of heat
** Peak capacity for 100 000 m^2 of solar panels
*** Peak charge and discharge rate for the the invested storage capacity

From figure 4.4, one can see that the yearly production is to a large extent dependent on natural gas. The direct CO_2 emissions are 92 kton per year which corresponds to an abatement cost of 1.18 SEK per kg of CO_2 [1] or 126 EUR per ton. The EU ETS (emission trading scheme) spot price is currently 7.3 EUR per ton of CO_2 [25].
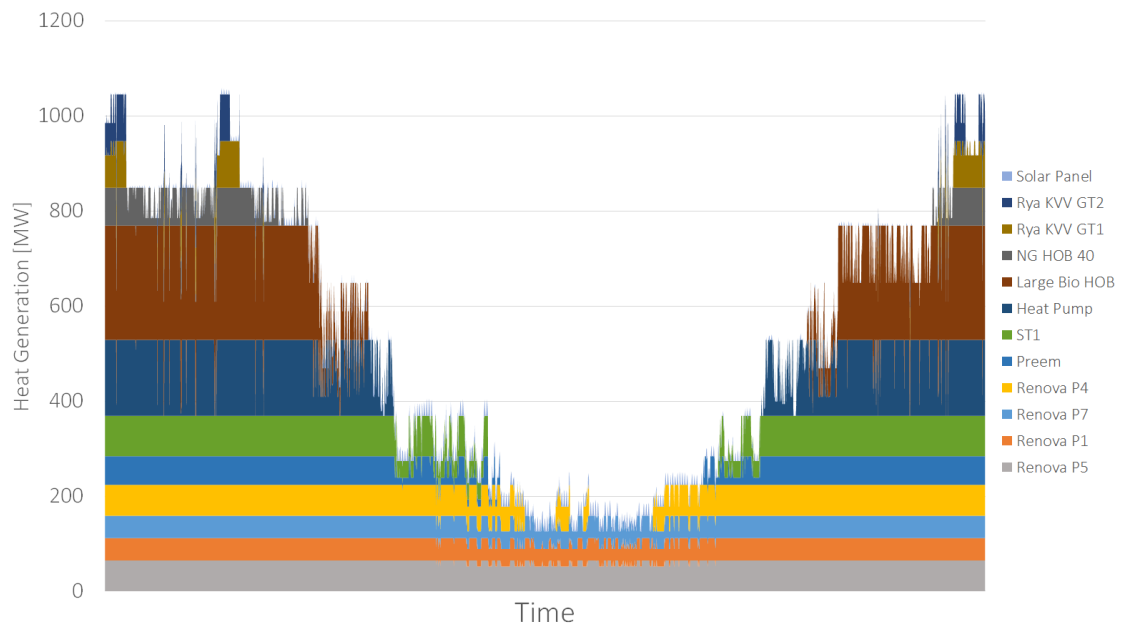

Figure 4.4: The production of a typical year with the system modelled in scenario of not meeting the CO_2 target

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[1]This is the cost difference of the scenario presented in 4.2.1 and this one divided by the total emissions in this scenario. This indicates at what cost the emissions can be avoided at the investment stage.

The excess heat sources, Renova and the oil refineries, are still utilised as base capacity. Below them in the merit order are the heat pumps which are run from the end of September until the beginning of May, with brief turn offs due to electricity price spikes. When the electricity prices are high, the large biomass HOB and natural gas HOB, which are below the heat pump in the merit order, also decreases production in order to make room for as much production as possible from the natural gas CHP:s, Rya gas CHP. The large biomass HOB's have long start up times, as such they only decrease production to minimum load level.

4.2.4 The oil refineries are shut down

Shutting down the oil refineries reduces the access to inexpensive excess heat in the district heating system. The municipal solid waste incineration plant Renova is still included in the scenario. The investments made by the model in this scenario are seen in table 4.5 below. The resulting system has a small palette of plant technologies and is, as shown in the sensitivity analysis, increasingly vulnerable to both changes in biomass prices and in electricity prices. The total system cost for this scenario is 1 577 MSEK per year.

Table 4.5: Production mix in the scenario without excess heat from the oil refineries. In the "Number of units" column, the number of units invested in and operated, are presented. This means that even though Rya KVV is still present in the system, it is not presented here as it is not operating

Plant Technology	Size	Number of units	Primary Fuel
Renova P1	47 MW	1*	Excess Heat
Renova P4	65 MW	1*	Excess Heat
Renova P5	65 MW	1*	Excess Heat
Renova P7	47 MW	1*	Excess Heat
Heat Pump	20 MW	8	Electricity
Large Biomass HOB	120 MW	4	Biomass
Solar Heating Panels	40 MW**	100 000 m^2	Solar radiation
El Boiler 10 MW	10 MW	3	Electricity
El Boiler 20 MW	20 MW	7	Electricity
TTES	±150 MW***	3000 MWh	District heat
PTES	±300 MW***	6000 MWh	District heat

* Already existing sources of heat
** Peak capacity for 100 000 m^2 of solar panels
*** Peak charge and discharge rate for the the invested storage capacity

Renova operates as base load capacity running throughout the year with the exception of briefly shutting down one furnace during parts of the low demand period. The model invests in new heat pumps, with approximately 5500 full load hours, to cover for the lost production that was previously supplied by oil refineries. Biomass fired HOB's cover the intermediate load demand with electric boilers being utilized for peak capacity. The biomass fired HOB's act to balance production, storage and demand during the year and fill in for the heat pumps when electricity prices are prohibitively high. Investments are also made in solar heating plants which are run

throughout the year forcing the other production units to remain flexible to cover for the intermittent solar production. The resulting dispatch can be seen in figure 4.5.
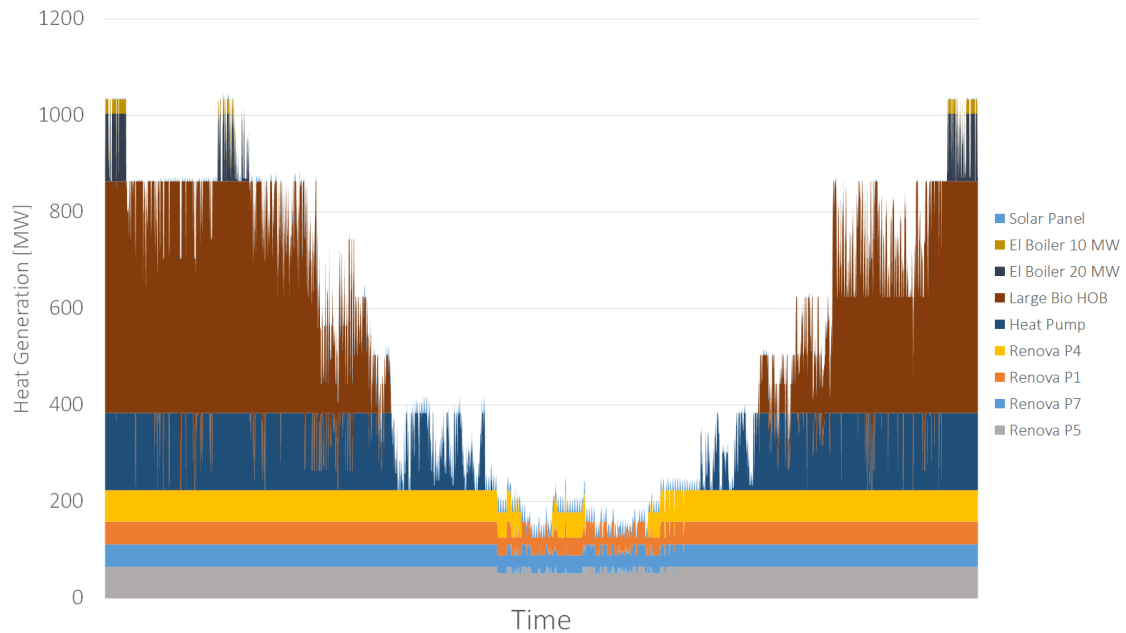

Figure 4.5: The production of a typical year with the system modelled in the scenario where the oil refineries are shut down

As can be seen, for a few sections during the beginning of the year the heat pumps seize generation due to high electricity prices. In order to enable this decrease in production the model utilizes the storage to buffer heat in anticipation of these price spikes.

4.2.5   All excess heat sources is replaced

This scenario represents a clean slate scenario assuming that all presently existing heat sources have been replaced by 2030. The result is a scenario with a system cost of 2 033 MSEK and a production mix consisting of eight heat pumps, used as base load capacity, three large biomass-fired HOBs and two extra-large biomass-fired CHP units, and peak capacity from electric boilers. Storage investments are made in 3000 MWh tank and 6000 MWh pit thermal storage, which is the maximum allowed in this scenario. The investments made in this scenario are presented in table 4.6

The model invests in new base capacity in the form of a 160 MW of heat pumps. During the summer the electricity price is low and stable and in combination with the heat pumps flexibility means that they can deliver the entire demand during the summertime and have over 8000 full load hours per year. The solar panels generate heat throughout the year, during summer this generation mostly charges

Table 4.6: Production mix in the "no excess heat" scenario. In the "Number of units" column, the number of units invested in and operated, are presented. This means that even though Rya KVV is still present in the system, it is not presented here as it is not operating

Plant Technology	Size	Number of units	Primary Fuel
Heat Pump	20 MW	8	Electricity
Extra-Large Biomass CHP	186 MW	2	Biomass
Large Biomass HOB	120 MW	3	Biomass
Solar Heating Panels	40 MW*	100 000 m^2	Solar radiation
TTES	±150 MW**	3000 MWh	District heat
PTES	±300 MW**	6000 MWh	District heat
Electric Boiler	10 MW	4	Electricity
Electric Boiler	20 MW	5	Electricity

* Peak capacity for 100 000 m^2 of solar panels
** Peak charge and discharge rate for the the invested storage capacity

the storage units. The summer load sometimes exceed that which the heat pumps can provide. In these instances the stored solar heat manage this excess. When the demand increases, in the beginning of the fall, the biomass-fired HOB is started as it is cheaper to start and has lower minimum power output than the CHP units. However, the HOB is then turned off to make room for the CHP units which are cheaper to run for longer periods of time. The CHP units are seldom turned off once they are turned on and therefore have about 5500 full load hours per year. The HOBs are the next unit in the merit order and are started as the demand increases beyond the capacity of the CHP units and the heat pumps, about 530 MW. The demand reaches above this 530 MW some time in the beginning of November and doesn't go below until the end of April resulting in over 3300 full load hours of HOB generated heat. The HOB:s are also used to balance the load during high electricity price periods when the heat pumps are too expensive to be used. The last units in the merit order are the electric boilers which are used as the peak load generation with less than 500 full load hours per year. The modeled years production can be seen in figure 4.6 below. Note the stable peak production level, at slightly above 1000 MW, where the storage serves to limit peak capacity need.
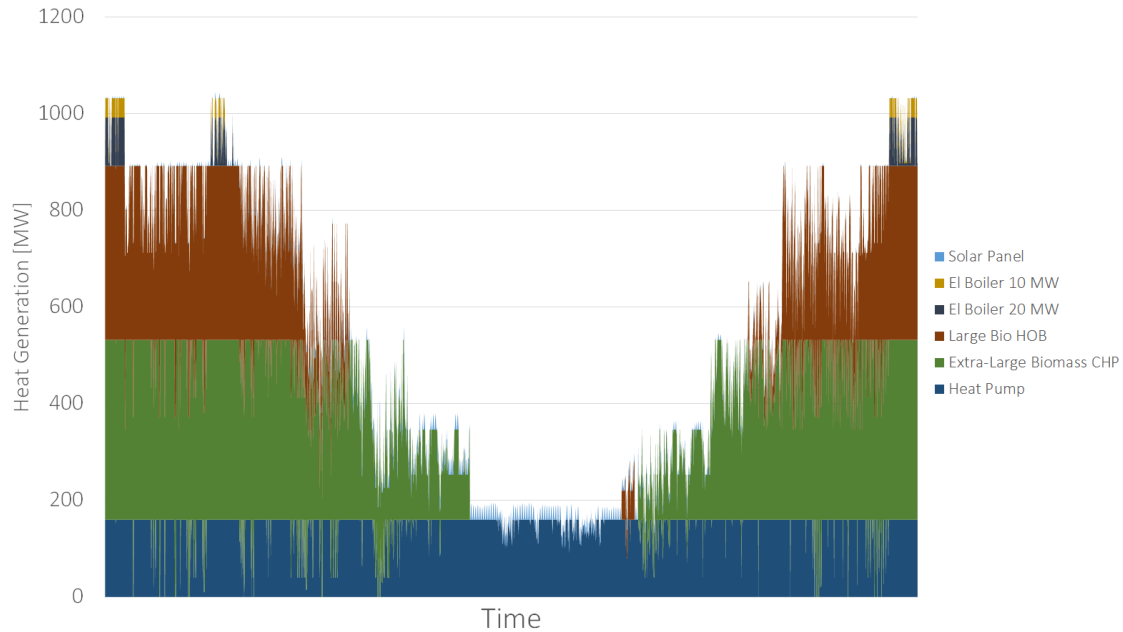
Figure 4.6: The yearly production of the system modelled in the no excess heat scenario

4.2.6 Green Certificates

The scenario of keeping the green certificate scheme until at least the year 2030 results in a system with an annual cost of 1 253 MSEK. The green certificates promotes electricity generation using renewable sources which is reflected in the investments made in this scenario. The system cost of this scenario without subsidy is however 1 346 MSEK which make it more expensive than the reference case if the subsidy would disappear. The investments are presented in table 4.7 and consist of a large number of heat pumps and electric boilers, thermal storage in both tanks and pits and two large biomass-fired CHP units. The model does not invest in any HOB:s or solar panels.

The base load in this scenario is supplied using the excess heat source from Renova which, with the exception of one unit, has over 8500 full load hours per year. When the summer has passed, in the beginning of september, the increasing demand for heat is supplied by the two refineries which are then running at full load until the summer comes again. In the beginning of October the biomass-fired CHP units are turned on, working as a intermediate load generation with over 4000 full load hours which yields a green certificate income of 137 MSEK. The eight heat pumps and the electric boilers are used as peak load generation with about 1800 and 500 full load hours, respectively.

As stated before, the system also includes thermal storage consisting of 3000 MWh of tank storage and 6000 MWh pit storage. The thermal storage operates as a storage for longer periods of time ranging from a couple of weeks to almost half a year. During these long periods of being charged, the storage charge and discharge

Table 4.7: Production mix in the scenario with green certificate scheme. In the "Number of units" column, the number of units invested in and operated, are presented. This means that even though Rya KVV is still present in the system, it is not presented here as it is not operating

Plant Technology	Size	Number of units	Primary Fuel
ST1 Refinery	85 MW	1*	Excess Heat
Preem Refinery	60 MW	1*	Excess Heat
Renova P1	47 MW	1*	Excess Heat
Renova P4	65 MW	1*	Excess Heat
Renova P5	65 MW	1*	Excess Heat
Renova P7	47 MW	1*	Excess Heat
Heat Pump	20 MW	8	Electricity
Extra-Large Biomass CHP	186 MW	2	Biomass
TTES	±150 MW**	3000 MWh	District heat
PTES	±300 MW**	6000 MWh	District heat
Electric Boiler	20 MW	7	Electricity

* Already existing sources of heat

** Peak charge and discharge rate for the the invested storage capacity

many times in order to balance production and load in order to prevent a potential start-up and shut down of plants.

4.2.7 Unlimited solar heating and storage investments

In this scenario the model is allowed to invest in unlimited amounts of solar heating panels and thermal storage. The total system cost in this case is 1 294 MSEK, which is significantly lower than the other scenarios and all investments can be seen in table 4.8 below.

Table 4.8: Production mix in the scenario with unlimited solar and storage. In the "Number of units" column, the number of units invested in and operated, are presented. This means that even though Rya KVV is still present in the system, it is not presented here as it is not operating

Plant Technology	Size	Number of units	Primary Fuel
ST1 Refinery	85 MW	1*	Excess Heat
Preem Refinery	60 MW	1*	Excess Heat
Renova P1	47 MW	1*	Excess Heat
Renova P4	65 MW	1*	Excess Heat
Renova P5	65 MW	1*	Excess Heat
Renova P7	47 MW	1*	Excess Heat
Heat Pump	20 MW	8	Electricity
Large Biomass HOB	120 MW	2	Biomass
Solar Heating Panels	409 MW**	1 021 502m^2	Solar radiation
PTES	13 034 MW***	260 670 MWh	District heat

* Already existing sources of heat

** Peak capacity for 1 021 502 m^2 of solar panels

*** Peak charge and discharge rate for the the invested storage capacity
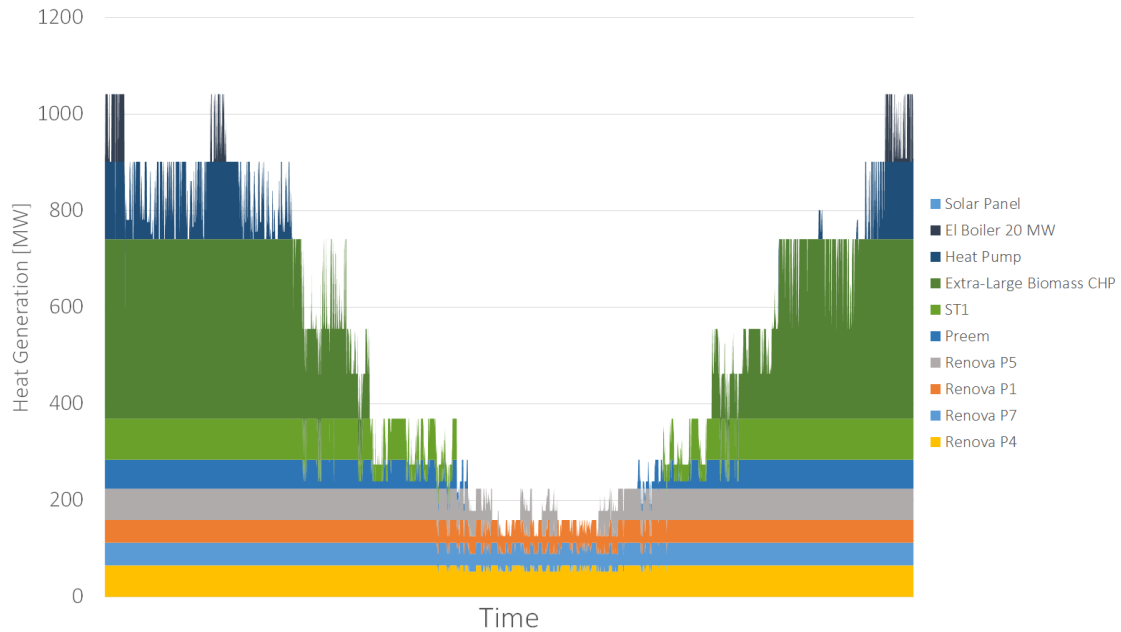
Figure 4.7: The yearly production of the system modelled in the scenario with green certificates scheme

The model uses Renovas furnaces heavily, three of the four furnaces have over 8 500 full load hours. The fourth furnace, Renova P4, has 7 850 full load hours and is turned off in June and remains so until mid July. During the entire summer period the furnaces at Renova vary their production in order to enable full production from the solar heating panels. The model invests in approximately one million square meters of panels, which at peak production produce 370 MW of heat. Below the Renova furnaces in the merit order is excess heat from the two oil refineries. These are utilized for 5650 and 5210 full load hours for Preem and ST1 respectively. They are both turned off during most of the summer when Renova and the solar panels are able to cover demand. For intermediate and peak level capacities the model invests in heat pumps and two large biomass HOB's. These are run for 4370 and 3450 full load hours respectively. In order to reduce peak capacity needs, incorporating large amounts of solar heating and load shifting the model invests in 260 000 MWh of pit thermal storage. This storage is charging heavily from the beginning of May and is reaching full charge around August or September. This stored energy is released both to even out solar production and to load shift seasonal variations. The storage begins discharging heavily in December, continuing until the beginning of February when it is fully depleted. The yearly production can be seen in figure 4.8 below.
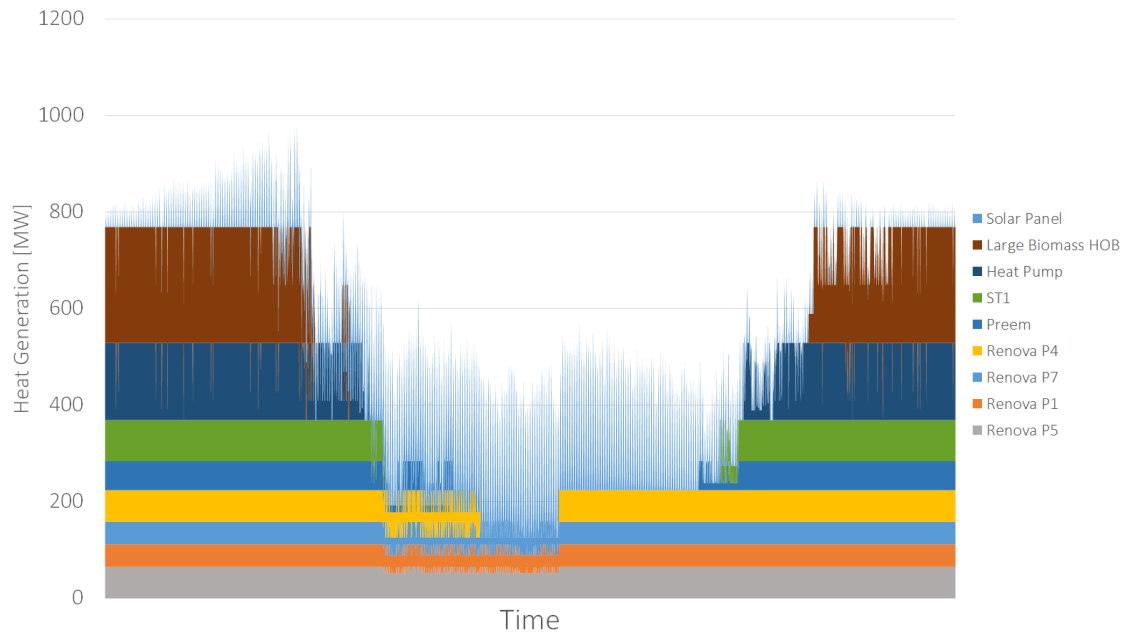
Figure 4.8: The yearly production of the system modelled with unlimited solar and storage investments

4.3 Sensitivity Analysis

The sensitivity analysis aims at investigating the robustness of some of the assumptions made in this thesis. In this chapter the general consequence of changing some uncertain parameters are analyzed. The systems that were invested in during the scenario studies are fixed in the sensitivity analysis. This analysis explores what impact changing uncertain parameters have on the operation of the systems. In table 4.9 the total system cost, as seen in the scenario study, is presented for each scenario together with the effects of changing these parameters.

The sensitivity analysis shows that systems with a large palette of plant technologies running on different fuels, are much more stable when external factors are varied. Generally an increased biomass price result in an energy shift from biomass-fired units to heat pumps. A system with a smaller variety in the production mix are however forced to use biomass-fired units no matter the cost which results in a much greater system cost increase for the system than if it would have a larger variety. If the electricity price is fluctuating more because of more wind power in the electricity system, the systems without CHP units has increased or unchanged system cost. The shift of energy goes from the heat pumps to biomass-fired units as these are cheaper for some periods of time. If the system includes CHP units, the system cost is decreased which derives from that the model, operating with perfect foresight, can utilize the price peaks and dips. Electricity consuming units, e.g. heat pumps, operate when the price is low whilst CHP units operate when the price is high.

Table 4.9: The resulting system cost increase when putting the studied scenarios through the sensitivity analysis

Scenario	System cost [MSEK]	Biomass [%]	Electricity [%]	Solar [%]	Loss factor [%]
Reference	1 368	10.5	0.2	0.0	0.2
No Storage	1 446	10.8	0.0	0.0	0.0
No Target	1 258	9.0	-1.3	0.0	0.3
No Oil	1 577	14.8	0.2	0.0	0.2
No excess heat sources	2 033	23.1	-4.2	0.0	0.1
Green certificate	1 253*	17.6	-4.3	0.0	0.2
Unlimited	1 294	8.7	0.5	0.1	Infeasible

* The revenue from selling the green certificates is included

4.3.1 Increased biomass price

In the scenarios the biomass price is assumed to be 255 SEK/MWh in the year 2030. There are several uncertain parameters associated with this forecast, e.g. the transportation sector may decide to use biomass in the process of producing fuels thus increasing biomass demand and prices. For this reason, it's important to investigate how the future production systems will cope with higher biomass price. A 50% price increase is analyzed. The main conclusions from this analysis are that the use of biomass-fired units is decreased compared to the initial price point and shifted to an increasing use of heat pumps. This leaves the system more dependent on the electricity price level and vulnerable to sudden electricity price peaks. The energy shift doesn't go downwards in the merit order as there is usually a big difference in running cost from the biomass-fired units to the next unit. The amount of energy generation shifted from biomass-fired units to heat pumps differs depending on how the production mix is composed.

With exception for the "Green Certificate" scenario, the scenarios with bulk parts of excess heat sources, refineries and waste incineration, the energy shift is in the range of 50 000 to 100 000 MWh/year. The shift is not bigger as the heat pump, operating at about 4000 full load hours a year, seems to have a maximum full load operation time of about 4700 hours a year. This is because the heat pumps are below the excess heat sources in the merit order. The heat pumps can therefore only operate during periods in which demand is above what the excess heat sources can generate. The system cost increase of these scenarios is smaller then one can expect as the systems are not as dependent on biomass-fired units as systems that don't have access to large excess heat sources. The system cost increase is about 10% for these systems, clearly showing how stable they are for rather drastic changes in fuel price.

The "green certificate" scenario is unique from a operational point of view as this is the only scenario where a biomass-fired unit is above heat pumps in the merit order. This is however changed when the biomass price is increased by 50% resulting in a massive energy shift of 450 000 MWh from the biomass-fired CHP units to the heat pumps. This is also reflected in the system cost which increases by about 17%

as compared with the original scenario, including the 30% decreased revenues from selling the certificate.

The "no oil refineries" and the "no excess heat" scenarios have less inexpensive excess heat generation than the rest of the scenarios. The heat pumps are however operating close to there maximum amount of full load hours, meaning that once they are turned on, they operate on full capacity untill they are turned off before the summer. The energy shift is therefore 54 000 MWh and 91 000 MWh for "no oil" and "no excess heat" respectively. This increases the system cost by 15% and 23% from a already high level compared to the other scenarios. One interesting aspect is that in the "no excess heat" scenario, the biomass-fired CHP unit changes place with the biomass-fired HOB in the merit order. This implies that the electricity price is not high enough to cover this increased fuel cost for the CHP unit. In other words, the combination of higher biomass prices due to higher demand and lower electricity prices due to more wind power in the electricity system may result in a scenario where biomass-fired CHP units are no longer competitive with biomass-fired HOBs.

The "unlimited" scenario is hit quite hard from an increased biomass price. The system is forced to utilize its biomass HOB for intermediate and peak load. The total system cost increases by 8.7% as compared with the standard case.

4.3.2   A change in the electricity system

There is a political climate in several European countries, including Sweden, that lobbies for a decommissioning of nuclear power. In Sweden the discussion whether or not nuclear power should be a part of the electricity system has been going on for several decades and the electricity system in the year 2030 may very well be without nuclear power. The effects this may have on the electricity has been modelled by Lisa Göransson [12] and utilized in this thesis. The modelling conditions is that Sweden has no nuclear power and 70 TWh of wind power is added to replace it. The resulting electricity price is shown in figure 4.9 and in full version in appendix 4.
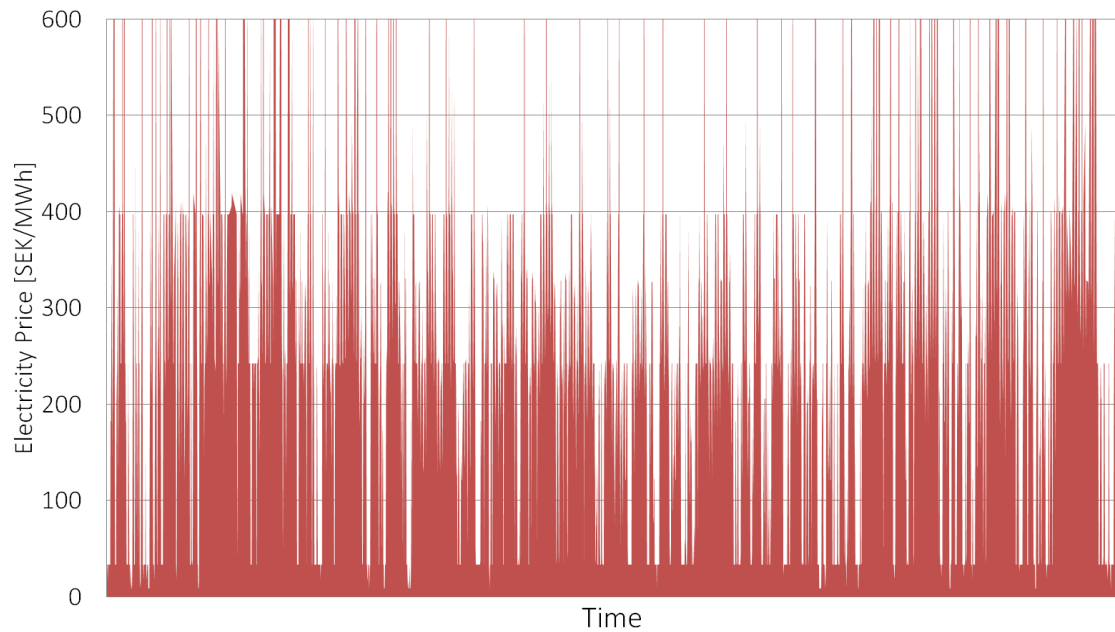
Figure 4.9: The market clearing price modelled under the condition that Sweden decommissions all nuclear power and replaces it with 70 TWh wind power.

Generally, as the average electricity price is higher, the heat pumps operate less and the energy is shifted to either non-electricity consuming units and/or electricity producing units. This is due to that during periods of time the electricity price is high enough to make other units pass the heat pumps in the merit order. How much and to what units the energy is shifted depends on the production mix in the respective scenario. As the heat pumps move down in the merit order they are no longer run during low demand periods. If storage possibilities were increased low electricity prices could be better utilized during low demand periods in order to lower system cost.

In the scenarios with HOBs in the production mix, the energy is shifted from the heat pumps to full or some extent to the HOBs. The increasing HOB-generated heat ranges from 65 000 MWh to 240 000 MWh, where systems with a larger variety of plant technologies shifts less energy to HOBs and systems with smaller variety shifts more energy.

The "Green Certificate" scenario is however an exception and not affected in this way. The fluctuating electricity price yields operating conditions where the biomass-fired CHP unit for some periods of time is more economical to run than all the excess heat sources, shifting energy from excess heat sources to the CHP unit. In this scenario, the heat pumps operate after the CHP in the merit order and therefore has relatively few full load hours. The new, fluctuating electricity price yields periods of time when the heat pump is very cheap to run and therefore shifts energy from some of the excess heat sources to the heat pumps. The summary is that the price peaks yields a energy shifts of 97 000 MWh from excess heat sources to the CHP unit and the price dips yields a energy shift of 43 000 MWh from the excess heat sources to the

heat pumps.

The "unlimited" scenario is not affected significantly by the change in electricity price. The total system cost increases by 0.5%. This is due to the fact that the system has to utilize its large heat pumps even while electricity prices are high.

Generally, the more fluctuating electricity price yields lower or practically unchanged (less than 0.5% increase) system cost which can be explained by the fact that the model has perfect foresight and access to load shifting via thermal storage. Systems including CHP units can also use the price peaks and dips in an optimal way, generating electricity when the price is high and consuming when the price is low.

4.3.3 Varying solar irradiation profile

The optimization results presented in the scenario study utilize average solar irradiation data for the years 1991 to 2000. Using average data evens out variations in the insolation curves. In reality the variability in solar insolation is greater than that against which the model is optimized. Ensuring the models robustness using real solar insolation data is therefore important. This is done by factorizing solar insolation data for 1994 and 1998, the years with lowest (92 % of average) and highest (105 % of average) solar insolation respectively. These years then provide the shape of the solar insolation curve which is then adjusted such that the total yearly energy irradiated is equal to that of an average year.

Using these alternative insolation curves no significant changes in total system costs are observed. The maximum change observed is in the "unlimited solar and storage investments" scenario using 1998's insolation profile. In this case the total system cost increases by 0.1 %, approximately 1.6 MSEK. In general all scenarios change their operations in order to adjust to the alternative insolation profiles, this does not significantly affect the system costs.

The model operates using perfect foresight. This allows the model to fully utilize available solar capacities. A real system cannot operate with perfect foresight but would likely operate more conservatively, under utilizing solar capacities in favour of conventional, more easily controlled, heat sources.

4.3.4 Increased storage loss factors

Thermal losses in thermal storage is dependent on temperature differences and conductivity from the heated water to the surroundings. This process is nonlinear making it difficult to model accurately. A further complicating factor is that the conductivity is dependent on the material surrounding the storage which can vary. In this thesis it is assumed that the losses associated with thermal storage can be simplified using a loss factor. Efforts are made to ensure that this is as accurate to reality as possible. This factor remains uncertain which is why it is interesting and important to analyze the models dependence on this loss factor.

Increasing the storage loss factors by a factor of ten results in slightly increased system costs. The increased system cost is relatively small and is in the range of 0 to 0.3%. Interestingly the scenario with unlimited solar and thermal storage investments becomes infeasible with increased loss factors. This system is highly dependent on the ability to store energy for utilization during nights, low irradiation times and high demand times.

The vulnerability to loss factors in the unlimited solar and storage investment scenarios prompt optimizing the model for these higher loss factors. This enables further studies into how the cost effectiveness of the system depends on this variable. In this optimization investments in solar panels are reduced to 319 602 m^2 as compared with 1 021 502 m^2 which is the case if using the lower loss factor. The same tendencies are seen in the thermal storage investments, which are reduced from 260 670 to 77 906 MWh. In order to cover for the lost solar capacity investments in another large biomass HOB are made, increasing biomass capacity from 240 to 360 MW. With these substantially lower investments in solar panels and thermal storage the total system cost becomes 1 349 MSEK, an increase of 4.3 % from the previous level. Securing the system against uncertainties in the storage loss factors can, as is shown, be done with quite low impact to the total system cost. This does entail increased dependence on other fuel sources.

Running the new configuration using the original, lower, thermal storage loss factor reduces the total system cost to 1 325 MSEK. This is a 2.4 % increase from the original system cost of 1 294 MSEK.

4.3.5   Increased solar panel investment cost

In the scenario studies it is observed that, if permitted, the model invests heavily in solar panels and thermal storage. It is interesting to study whether this behaviour remains at higher solar panel costs. Running the optimization model for the reference scenario with solar panel investment costs that are 10% higher removes almost all investments in solar panels. Using this higher investment cost the model invests in approximately 7900 m^2 of panels. With these lower investments in solar heating the model does not invest in any additional capacities. The solar panels can thus be seen to provide mainly energy, as opposed to capacity. 100 000 m^2 of solar power provide below 40 MW at peak performance, but generate heat at very low cost thus enabling fuel savings in other units.

The investment costs for solar heating panels are based upon [9] and its source report. These costs do not include the price of land or the leveling of land. According to [26] the costs for large, 50 000 m^2, ground mounted solar collector fields is likely between 150 to 230 euro per square meter, also excluding the cost of land and leveling. They estimate that land may be bought for five euro per square meter. This by itself increases costs of the installation by approximately 2.5%. The land value in and around the city of Gothenburg is high. Dedicating large areas of land to solar collector fields may therefore be costly, reducing the competitiveness seen in this thesis of the technology.

5

Discussion

In this chapter the relevance and validity of the results are discussed. Important aspects to consider with the scenario studies and the various sensitivity analyses are also discussed.

5.1 Reserve Capacity

The Gothenburg Climate Program states that district heating generation should be fossil free by 2030, but in extreme situations and emergencies, fossil heat and electricity generation is still permitted. The document doesn't include a definition of what an extreme or emergency situation is and therefore leaves room for interpretations such as, the coldest day of the year may be considered an extreme situation. The model constructed for this thesis doesn't include this reserve capacity and one can therefore argue that the model doesn't fully represent Gothenburg 2030 stated in the Climate Program. The model does however still include the plants present in today's system that haven't been decommissioned by year 2030, i.e. Rya KVV, which run on fossil fuels. These units are not used during the modelled year operation and can therefore be considered to be saved as back-up units only to be used in extreme and emergency situations.

5.2 Green Certificates

The green certificate scheme is currently set to expire in 2035 at the latest [22]. With this in mind it is not certain that the scheme is still in effect in the studied year. The cost and subsidy stemming from green certificates depends on quotas set by policy makers and the cost of other options to generate green electricity. Estimations for price level of certificates are with this in mind difficult to assess accurately. In the "green certificate" scenario it is seen that with a certificate subsidy of 204 SEK per MWh investments in biomass CHP units are favoured to biomass HOB:s. These results are valid for a scenario where Swedish nuclear power plants are still operational. In a future with an increased share of intermittent sources and fewer nuclear power plants, wind power plants will increasingly be price setting on the electricity market. In this case the investment costs in wind power plants will have

to be covered by some other income source. If green certificates are used to this end it will greatly benefit non-intermittent renewable power production such as biomass CHP units. These technologies are able to generate electricity while prices are high and still get certificates for each MWh produced. In such a future it is likely that CHP units will be increasingly attractive in district heating networks.

5.3 Investment Limitations

The models are generally run with limitations on how much thermal storage and solar heating panels the system can include. The model runs show that both solar heating and thermal storage has a greater potential in a future district heating system than we expected and therefore a scenario without limitations on solar and storage investments were constructed.

When the model is run without limitations, the investments in solar heating panels reaches 1 021 501 m^2. This is an area approximately the size of downtown Gothenburg, within the mote or roughly three times the size of Chalmers campus Johanneberg. This can be compared with the largest solar heating unit in the world, in Marstal, Denmark, which has a size of 33 300 m^2 [27]. The maximum heat generation of a solar heating plant of about 1 000 000 m^2 located in Gothenburg is approximately 400 MW which would last for a few hours in the middle of a summer day before decreasing until it reaches zero when the sun sets. Such extreme differences require large thermal storage capabilities to distribute the energy throughout the day and the year. Therefore, the unlimited scenario invests in 260 670 MWh of pit thermal storage which is equal to a volume of about 3.7 million m^3. This is a volume comparable to 29 gas bells in the size of the Gothenburg gas bell which is 81 meter high and has 45 m in diameter. The world's largest pit storage has a volume of 75 000 m^3 making this one about 50 times bigger.

However, not having limitation lowers the system cost by only 73 MSEK, 5%, which may not be worth while when comparing these savings to the associated risks. These risks may include not being able to satisfy demand during cloudy periods.

The heat pumps are limited so that the model can not invest in more than eight 20 MW-heat pumps. This is due to that the today existing heat pumps has a maximum heat output of 160 MW and we assume that the amount of sewage water will not increase significantly until 2030. However, we have assumed that the heat demand, which can be coupled with the population growth, will increase by 20% until 2030 hence an increased amount of sewage water can be expected. A projection of the amount of sewage water in 2030 and how much heat that can be extracted from it is not part of this thesis' scope. The amount of sewage water is most likely not to decrease which is why a limit of 160 MW is used. If one can extract more heat in 2030, the result from this thesis indicates that heat pumps are beneficial and a large number of heat pumps are desirable.

5.4 Cost assumptions

In the literature study numerous sources to investment costs were found. All reported specific investment costs that were similar for conventional technologies. The model mainly compares new investment alternatives to each other and not to existing units. With this in mind we do not believe that using other reliable updated sources for the investment costs of conventional technologies will yield a significantly different result.

Solar heating and thermal storage costs are based upon fewer sources than those for conventional technologies. Thermal storage is invested in even at 50% increased investment costs. The sensitivity analysis for solar heating showed that it is highly sensitive to increased investment costs. The investment costs for solar heating do not include the cost of land. This is a factor we believe to be highly important for investments in or around Gothenburg.

5.4.1 Fuel costs

The bulk of the fuel costs are based on a report written by Axelsson et al. [21] from Profu AB in which a prognosis of the fuel prices for 2030 is presented. The prices of fuels is fluctuating and drastic price changes can occur quickly for geopolitical reasons. With this in mind the prices presented in this report do not significantly deviate from prices found from other sources and therefore we believe that they are reliable.

The prices on excess heat are dependent on many factors e.g. what the source is, what business model is applied and what the district heating company is willing to pay. The contract including the cost of excess heat is usually classified and so is the cost of heat coming from Renova and the refineries. For this reason we have in this thesis made an assumption on the cost of excess heat. The cost assumptions are constructed so that excess heat is the base load capacity in the reference case which is in line with how it is in today's system. The results shows that in the scenarios where excess heat is available, it is operated as a base load generation as anticipated. This indicates that the cost assumption made for excess heat is not affecting the investment decision and has a limited effect on how to operate the system. However, if the actual cost of excess heat would be available, the result from this thesis would be much more accurate and the costs would be closer to what one can expect in 2030.

5.5 Interest rate

Göteborg Energi is currently operated for profit and owned by the municipality. In this thesis it is seen that investments in solar heating panels are cost efficient at 3% interest. A for-profit company will likely use a higher discount rate for investments

decreasing the competitiveness of technologies with large investment costs. The municipality exists to serve its citizens and focusing on longer time scales should match the interests of Göteborg Energi.

5.6   Validity

The model is run with 2920 time steps and without ramp restrictions for any generation facility. We have seen that running the model with a temporal resolution of 2920 steps does not significantly alter the decisions made by the model as compared with a resolution of 8760 steps. Including ramp up and ramp down restrictions for technologies in accordance with [10] does not significantly affect the model operations and dispatch. Including ramp restrictions does increase computation time which is why it has been omitted in the model. We have in similar evaluations of the model seen that the ability to charge the district heating system has significant impacts in how the model operates.

Charging the net is used by the model to bridge fluctuations in demand. Without this ability there are cases when the model has to decrease production in several units in order to respond to a sudden decrease in demand. This results in a cascading effect throughout the production units where, in order to keep units above their minimum production, they all reduce their production to their minimum capacity. Charging the net allows the model to decrease production in just some units and utilize the net as a high loss, 1% per hour, thermal storage unit.

The amount of energy stored by charging the net is estimated to be 900 MWh. This was calculated by assuming that the properties of water in the net are the same as for water at 20 °C and atmospheric pressure. It can be discussed whether or not these assumptions are correct as there are uncertainties associated with this calculation. The temperature deviation may exceed 5 °C for short periods of time, the network is pressurized and at a higher temperature than 20°C which results in other thermal properties for water. However, a quick test shows that exact thermal properties of water has a rather small effect on the overall thermal storage of the network.

6
Conclusions

This thesis demonstrate that there are many ways to construct and operate a district heating system which satisfies the climate program for Gothenburg. The target is met by constructing biomass-fired units, heat pumps and electric boilers which in combination with pit and tank thermal energy storage is enough to cover the generation loss caused by decommissioning. The extensive use of biomass makes the system vulnerable for a price development with higher costs for biomass than predicted. The effect of this price deviation can however be dampened by having a large palette of generation technologies that run on different fuels, preferably increasing excess heat sources. The system's exposure to electricity price fluctuation appears not to be a problem even in the scenario of Swedish nuclear power being replaced by wind power. If the production mix includes both CHP units and heat pumps, the system cost can be decreased by using CHP units during high price periods and heat pumps during low price periods. This requires accurate price and load projections.

In a system with access to large excess heat sources there is no need to invest in new base load generation as no plant technology can compete with the inexpensive energy that they provide. Rather there is a need to invest in intermediate load generation that has lower investments costs but still can provide relatively cheap heat. The models indicates that heat pumps and large biomass-fired HOBs are the most preferable choice of intermediate load generation as these have high efficiencies and are cheap to build. The peak load is supplied using electric boilers which are cheap to build but expensive to have in operation. If the system does not have access to excess heat, investments in biomass-fired CHP units seem favorable to replace the loss of base load generation. The CHP units have higher investment cost but lower running cost compared to a HOB:s hence when operated for longer periods of the year makes it more attractive from a economical point of view. CHP have also been proven viable if the green certificate scheme is still in effect in 2030.

This thesis indicates that solar heating panels are favourable in a future district heating system in Gothenburg. The solar heating panels are viable in a system irrespective of both thermal storage and the CO_2 target. The analysis shows that the investments exceeding 1 000 000 m^2 are cost efficient, however, analysis also demonstrates that if the investment cost is increased by just 10%, the investments are less than 10 000 m^2 indicating how exposed this investment is to price increases.

With a discount rate of 3% investments in up front expensive technologies are seen.

Companies considering investments in district heating are likely utilizing higher rates and payback periods lower than the technical lifetime. Such a shift will remove incentives for investments in solar heating panels and likely shift focus from biomass HOB:s to fossil fired HOB:s due to their lower investment costs.

The scenarios clearly demonstrate the value of thermal energy storage by investing in the maximum size in almost every scenario. The thermal energy storage operates both as peak clipping, valley filling and load shifting meaning that it supplies during peak load using energy stored from periods of low load and can shift the operational hours of for example electric boilers, to periods with more favourable conditions. Even though the thermal storage do not generate any heat, this thesis demonstrates that it can have an important role in a future CO_2 free district heating system in Gothenburg.

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I

A

Appendix 1 — Economic properties of new investments

Table A.1: Economic properties of investment alternatives in SEK for 2015

Technology	VC [SEK/MWh]	FC [SEK/MW]	IC [SEK/MW]	Source
Increased excess heat	0.8	0	25 000 000	[28]
Heat pump	11.2	67 200	6 720 000	[3]
Small biomass HOB	22.4	119 840	9 632 000	[6]
Medium biomass HOB	22.4	112 000	8 960 000	[6]
Large biomass HOB	22.4	101 920	8 176 000	[6]
Solar heating panels	5.1	0	1 875.9*	[9]
Tank thermal storage	0	0	14 159**	[7,8]
Pit thermal storage	0	0	3 694**	[7]
Borehole thermal storage	0	0	5 986***	[7]
Small biomass CHP	33.0	448 000	20 249 600	[5]
Medium biomass CHP	38.0	370 944	18 144 000	[5]
Large biomass CHP	42.3	272 832	16 228 800	[5]
Extra large biomass CHP	41.9	183 008	12 280 800	[5]
El boiler 10 MW	11.2	16 800	1 120 000	[6]
El boiler 20 MW	11.2	16 800	1 120 000	[6]
Heat pump for BTES	11.2	67 200	6 720 000	[3]
Natural gas HOB 40 MW	16.8	28 000	4 480 000	[6]
Natural gas HOB 100 MW	16.8	28 000	4 480 000	[6]
Natural gas combi CHP 40 MW	21.6	294 737	12 280 702	[5]
Natural gas combi CHP 150 MW	13.8	172 308	8 184 615	[5]

* Investment cost for solar heating panels in SEK per m²
** Investment cost for storage in SEK per MWh
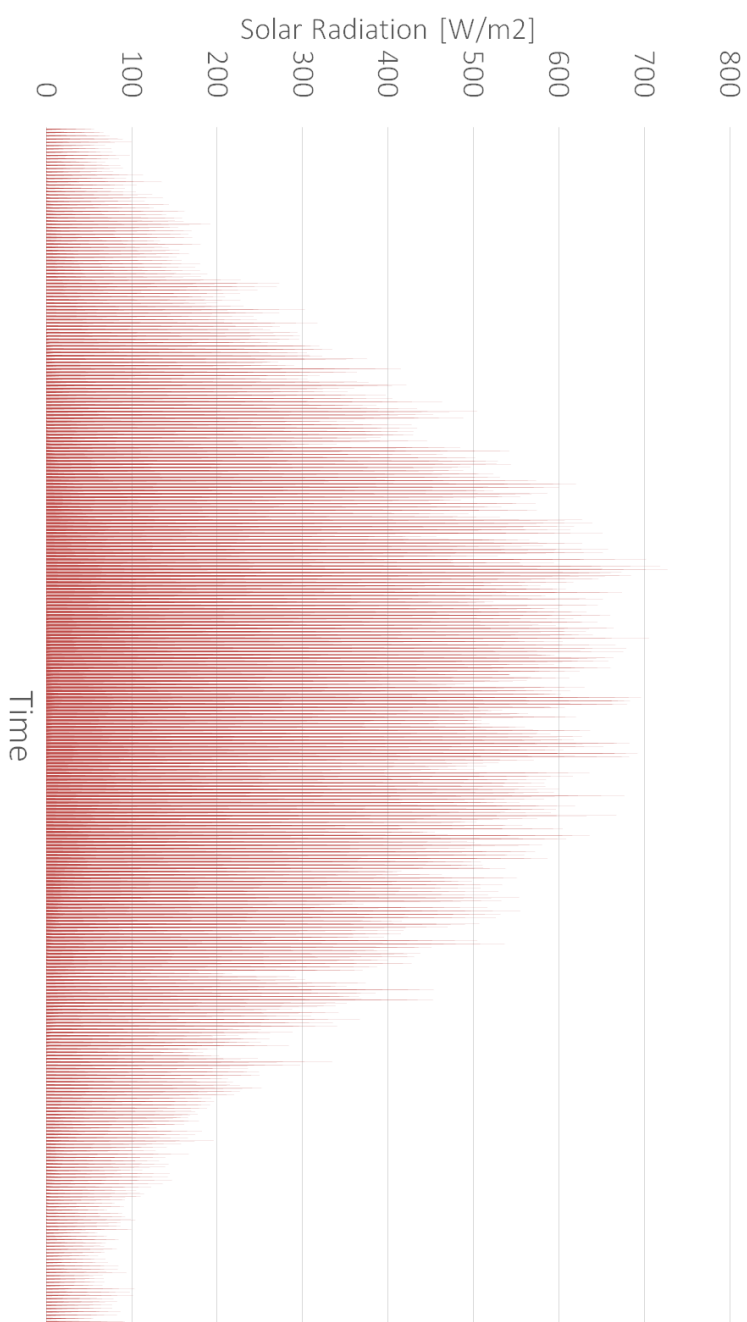
B

Appendix 2 — Solar irradiation curve

Figure B.1: The hourly average solar irradiation in Gothenburg calculated between the years 1991 and 2000.
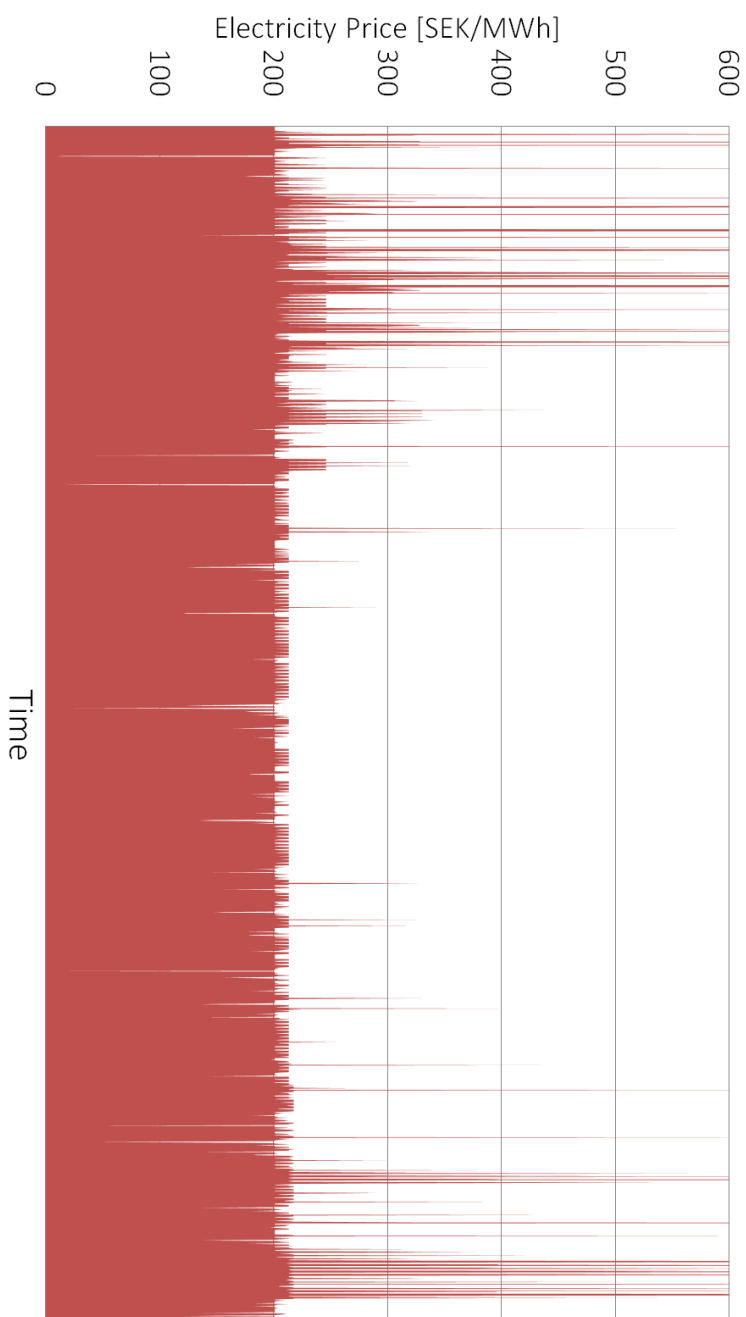
C

Appendix 3 — Electricity price

Figure C.1: The electricity market clearing price i.e. the selling price of electricity for each time step for the year 2030. The buying price of electricity is calculated by adding the Gothenburg transmission cost and the Swedish energy tax. The electricity price exceeds 600 SEK per MWh at times but for readability these peaks have been cut in this figure.

D

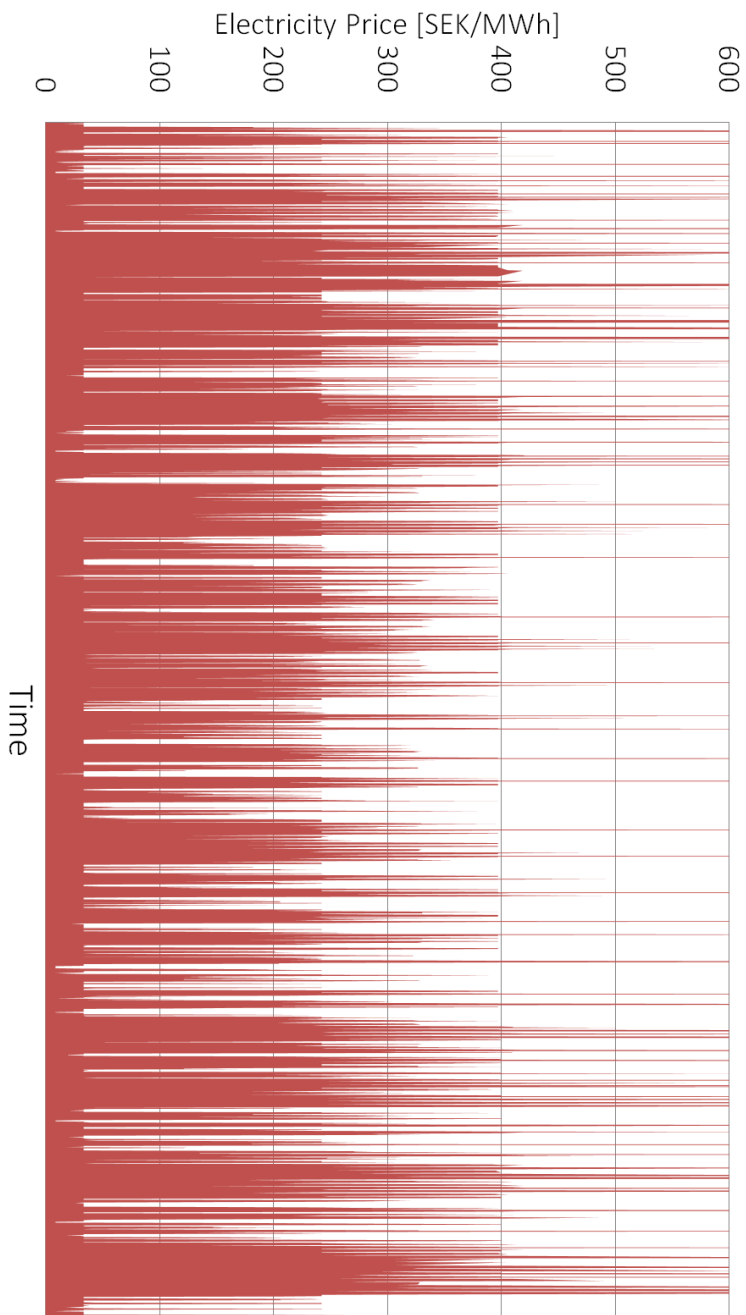# Appendix 4 — Electricity price with wind power replacing nuclear

Figure D.1: The electricity market clearing price i.e. the selling price of electricity for each time step for the year 2030 assuming that no nuclear reactors are operational and have been replaced with wind power. The buying price of electricity is calculated by adding the Gothenburg transmission cost and the Swedish energy tax. The electricity price exceeds 600 SEK per MWh at times but for readability these peaks have been cut in this figure.

E

Appendix 5 — Technical properties of new investments

Table E.1: Technical properties of investment alternatives

Technology	P_{max} [MW]	P_{min} [MW]	STUP [h]	η	α	Source
Increased excess heat	150	50	8	1	0	[28]
Heat pump	20	5	1	3	0	[3]
Small biomass HOB	21	10.5	3	0.95	0	[6]
Medium biomass HOB	68	34	6	0.95	0	[6]
Large biomass HOB	120	60	8	0.95	0	[6]
Solar heating panels	1	0	1	0.4	0	[9]
Tank thermal storage	0.05*	-0.05*	1	20**	0	[16]
Pit thermal storage	0.05*	-0.05*	1	20**	0	
Borehole thermal storage	0	0	1	0	0	
Small biomass CHP	15.6	7.8	2	0.78	0.32***	[6]
Medium biomass CHP	27.8	13.9	4	0.78	0.36***	[6]
Large biomass CHP	71.4	35.7	12	0.74	0.42***	[6]
Extra large biomass CHP	186.0	93.0	18	0.77	0.43***	[6]
El boiler 10 MW	10	1	1	0.95	0	[6]
El boiler 20 MW	20	1	1	0.95	0	[6]
Heat pump for BTES	∞	−∞	1	3	0	[3]
Natural gas HOB 40 MW	40	8	1	0.92	0	[6]
Natural gas HOB 100 MW	100	20	1	0.92	0	[6]
Natural gas combi CHP 40 MW	35.1	24.6	1	0.42	1.14	[5]
Natural gas combi CHP 150 MW	115.4	80.8	1	0.40	1.3	[5]

* Charge and discharge is this factor multiplied by total storage size

** The storage is assumed to require 5% pumping power, thus having an "efficiency" of 20

*** Results in a total efficiency above 1 due to using lower heating value of fuels