CHALMERS
UNIVERSITY OF TECHNOLOGY

The future development of district heating in Gothenburg

Master's thesis in Sustainable Energy Systems

JOHAN HOLM & JONAS OTTOSSON

Department of Building Service Engineering
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2016

Master's thesis 2016:BOMX02-16-144

The future development of district heating in Gothenburg

JOHAN HOLM & JONAS OTTOSSON

CHALMERS
UNIVERSITY OF TECHNOLOGY

Department of Building Service Engineering
Chalmers University of Technology
Gothenburg, Sweden 2016

The future development of district heating in Gothenburg

JOHAN HOLM & JONAS OTTOSSON

Supervisor: Johan Kensby, Department of Building Service Engineering
Examiner: Anders Trüschel, Department of Building Service Engineering

Master's Thesis 2016:BOMX02-16-144
Department of Building Service Engineering
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

The future development of district heating in Gothenburg
JONAS OTTOSSON & JOHAN HOLM
Department of Building Service Engineering
Chalmers University of Technology

Abstract

Göteborg Energi is the sole provider of district heat in the Gothenburg region in Sweden. By the year 2030, the generation of heat in Gothenburg is planned to be free of fossil fuels. The plans include the construction of a biomass-fuelled combined heat and power plant and an increased use of bio gas. These plans are already set, but there are many possible additional measures that could be implemented in the district heating system that will help to meet the targets set for 2030. However, the future is hard to predict and it may be difficult to choose which measures to implement.

In order to assess the possible measures to be implemented, an optimisation study through the software GAMS has been performed in this thesis: a model of the generation of district heating in Gothenburg has been created and 4 different scenarios where measures to decrease total system running costs have been implemented by the year 2032 have been studied. These measures are: seasonal thermal energy storage, thermal energy storage in buildings, thermal energy storage in a hot water accumulator tank and an increased use of exhaust air heat pumps in buildings. The district heating system is affected by the electric system in several ways through the price of electricity. In the future, when more electricity is generated from intermittent sources such as wind or solar, the price of electricity will be fluctuating and the district heating system must be able to handle these fluctuations. The optimisation is performed on an hourly basis and includes hourly prices for electricity that have been previously simulated for 2032.

It was found that it is possible to achieve a fossil-free generation of heat in Gothenburg by 2032. The studied measures all give system cost savings in the form of reduced running costs. By introducing thermal energy storage in the district heating system, substantial savings in running costs can be achieved, as well as reduced heat load variations on both daily and seasonal levels. By using buildings as thermal energy storage, similar cost savings as for an accumulator tank can be achieved, but at much lower investment cost. A seasonal thermal energy storage will give large cost savings and heavily reduced heat load variations, but at a very high investment cost. With an increased amount of exhaust air heat pumps in buildings, the total running costs of the heat generation system can be reduced. However, these heat pumps will give a small increase in heat load variation on a system level.

Keywords: District heating, optimisation, thermal energy storage, exhaust air heat pumps, MILP.

Acknowledgements

We would like to thank our supervisor at Chalmers University of Technology, Johan Kensby for his great support throughout the work. He has given as many good ideas and excellent input, as well as access to table tennis, which has been a life-saver when things have been tough.

We also thank our supervisor at Göteborg Energi, Claes Sommansson for giving us the opportunity to write this thesis and for supporting us with material and inspiration.

Our thanks also go out to Dmytro Romanchenko and Joel Goop at Chalmers department of Energy and Environment for their valuable support and input.

Jonas Ottosson & Johan Holm, Gothenburg, November, 2016

Contents

Abbreviations and Symbols

Abbreviations

CHP	Combined Heat and Power
CM	Climate Market
COP	Coefficient of Performance
CTES	Cavern Thermal Energy Storage
DH	District Heating
EAHP	Exhaust Air Heat Pump
GAMS	General Algebraic Modeling System
GP	Green Policy
HOB	Heat Only Boiler
HP	Heat Pump
HVAC	Heating, Ventilation and Air Conditioning
LP	Linear Programing
MILP	Mixed Integer Linear Programming
REC	Renewable Electricity Certificates
RP	Regional Policy
TES	Thermal Energy Storage

Symbols

α	Power to Heat ratio	[-]
T	Temperature	[°C]
E	Energy	[MWh]
P	Power	[MW]
V	Volume	[m^3]
C	Cost	[MSEK]
Q	Heating Power	[MW]
W	Pump Work	[MW]
η	Efficiency	[-]
t	Time Variable	[hours]

1
Introduction

The world is facing perhaps its greatest challenge ever in the form of global warming. In order to limit rising temperatures, the use of fossil fuels needs to be reduced in all sectors both by reducing the primary energy use and by replacing fossil fuels with renewable fuels. The building sector is the largest user of energy both in Sweden and globally, where the energy is used for heating, cooling and ventilation. The heating of buildings can be performed in many different ways, i.e. direct electric heating, combustion of various fuels in each building or by district heating (DH). Where district heating is available, the use of fossil fuels can be reduced by switching to renewable fuels such as biomass and by increasing the efficiency in heat generation plants (Frederiksen et al. 2013).

In the city of Gothenburg in western Sweden, the utility Göteborg Energi is the sole provider of district heat. Today, district heat is generated through several ways including utilisation of industrial excess heat and heat from municipal waste, combustion of biomass, natural gas and other fossil fuels. In the year 2012, 19% of the generated heat in Gothenburg stemmed from the combustion of fossil fuels (Göteborg Energi 2012). By the year 2032, Göteborg Energi has the ambition to reduce this share to zero in order to comply with goals set at global and European levels. This is to be achieved through the construction of a new combined heat and power (CHP) plant and by replacing natural gas with bio gas in heat generation plants (Göteborg Energi 2016a).

In practice, this will lead to a heat generation without any use of fossil fuels, but the running cost of this future system will be higher than what they are today. In order to decrease the total system running costs of the heat generation, Göteborg Energi can choose to invest in different types of thermal energy storage (TES). Thermal energy storage can help reduce the operation of expensive peak-load covering heat generation plants and decrease the variation in heat load overall, giving benefits in the form of improved efficiency in heat generation plants and reduced need for maintenance (Heier 2013). In addition, by the year 2032, there may be an increased use of heat pumps utilising exhaust air as their heat source in buildings in the Gothenburg area. Heat pumps use electricity to efficiently generate heat and extensive use of them will have an effect on the generation of district heat (D. Olsson 2016b).

The performance of the thermal energy storage and the effect of an increased use of exhaust air heat pumps described above will depend on a number of factors in a future heat generation system. Temperature, demand for heat and electricity prices will all affect the cost savings that can be achieved from both thermal energy storage and exhaust air heat pumps. In order to make an evaluation of the different scenarios that could arise in the heat generation system of Göteborg Energi, an optimisation model has been used. The optimisation model uses hourly data regarding heat demand and electricity prices in the year 2032 and shows how the heat generation system is operated. Six major scenarios are studied, which are introduced in the following list:

- Reference scenario: How is the heat generation system of Göteborg Energi operated in 2032 if a new wood chip CHP is constructed and natural gas is substituted by bio gas?
- Thermal energy storage in an accumulator tank
- Utilising buildings as thermal energy storage
- Seasonal thermal energy storage
- Increased use of exhaust air heat pumps
- Ability to shift heat source when both exhaust air heat pumps and district heating is used in a building

This thesis can thus be seen as a pre-study giving guidelines for Göteborg Energi regarding what investments could be made in order to achieve cost savings in the generation of heat in the future.

1.1 Purpose

The purpose of this thesis is to evaluate how different thermal energy storage options and an extensive deployment of exhaust air heat pumps could affect the heat generation system of Gothenburg in the year 2032.

The evaluation will be performed by creating different optimisation models of the heating system in 2032. These models will represent different future scenarios where the effect of acquiring thermal energy storage capacity or deploying exhaust air heat pumps can be studied. The optimisations shall yield the total yearly system running costs as well as hourly marginal price for generating heat and the hourly heat generation for the individual heat generation plants. The costs and operation of heat generating plants for the future scenarios will be compared to a reference case for 2032 were no thermal energy storage or deployment of exhaust air heat pumps are deployed. Also, the effects that differing electricity prices will have on the heat generation system are studied.

1.2 Research questions

The thesis aims to answer the following question:

- How will the implementation of thermal energy storage or exhaust air heat pumps affect the cost, dispatch and environmental impact of heat generation?

Related to the above, the following questions shall be answered:

- How will different development scenarios in the electricity system affect the performance of the introduced technologies in 2032?
- How are the different thermal energy storage technologies used?
- How will the exhaust air heat pumps affect the heat load deliveries from the district heating utility?
- What are the additional system benefits from enabling a smart control of the exhaust air heat pumps?

1.3 Scope

The modeling will be limited to altering an existing model of the district heating system in Gothenburg. The price of electricity is retrieved from an external source and is not modelled internally. Electricity prices are dependent on weather data since the generation from wind and solar sources are directly linked to e.g. wind speed and insolation. The demand for heat is also closely coupled to the weather and especially the outdoor temperature. Since the price of electricity is received from an external model, which is based on specific weather data, it is important that the weather data used for the model in this thesis is identical to the weather data used as input for the external electric model. This is needed because the demand for heat in each hour of the year has to be correlated with the correct hourly price for electricity.

The district heating network of Gothenburg are connected to several other neighboring district heating networks and district heat can be exported and imported between these networks. In this thesis only the heat load in the Gothenburg network is modeled and no import or export is considered.

It will be assumed that there are no feedback effects between the heat system and the electric system. In other words, the use of electricity in the heat system (heat pumps, electric boilers) will not affect the price of electricity. In reality, the demand for electricity in the heat sector will have some effect on the price of electricity, but since the studied system is relatively small, the effects can be neglected.

No installation costs or fixed costs will be taken into account when performing the optimisations. The only costs that are considered are the running costs and start up costs of the heat generation plants.

2
Theory

This thesis studies the impact of various possible future developments of the district heating system in Gothenburg. therefore, some background is needed in order for the reader to better understand the results. In this chapter, the background and theory of the studied district heating system and possible additions to it are presented and explained. The current district heating system of Gothenburg is reviewed, followed by theory regarding the future heat demand and electricity prices. Finally a description of the technologies that are considered possible and relevant for introduction in the system is presented. These descriptions are based on a literature study, along with personal communications at Göteborg Energi.

Since the thesis is concerning the future district heating system, it is worth defining what "future" means in this case. In the European Union, there is an ambitious climate target policy in place. By the year 2030, there should be an at least 40 % decrease in greenhouse emissions, compared to 1990. At least 27 % of the used energy in the EU should come from renewable sources and there should be an at least 27 % improvement in energy efficiency (European Comission 2016). Therefore, it is of interest to see how the Gothenburg district heating system is operated in 2030. In order for policies to take full effect, the studied year is adjusted to 2032.

2.1 The District Heating System in Gothenburg

The fundamental idea of district heating (DH) is to use a local fuel or heat resources that would otherwise be wasted, in order to satisfy local customer demands for heating. The heat is distributed to customers via a distribution network of pipes and the heat demand typically comprise of space heating and heating of hot water in residential, commercial and public buildings (Frederiksen et al. 2013). In Gothenburg, the heat is supplied to a large extent by excess heat from refineries in the area and waste incineration. This makes the Gothenburg district heating system different from most other typical district heating systems both in Sweden and the rest of the world (Göteborg Energi 2014). The heat from waste incineration together with the excess heat from the refineries is referred to as excess heat in this report.

The excess heat is available to Göteborg Energi at a very low cost, and is therefore used to as large extent as is possible throughout the year. In addition to a supply of excess heat, Göteborg Energi owns and operates two large combined heat and power (CHP) plants, Sävenäsverket and Ryaverket, which are fuelled by biomass and natural gas. These large CHP units are primarily run to cover base and intermediate loads. The utility also utilises two large scale heat pumps (HP) that uses cleaned sewage water as their cold sides. In addition, Göteborg Energi operates a large facility, Rosenlundsverket, with turbines and boilers running on natural gas and oil to generate both heat and electricity for peak load hours. Göteborg Energi also owns and operates a large number of small scale heat generation plants as back-up and to cover peak loads. These plants are all boilers that are denoted as heat-only boilers (HOB), which simply mean that they do not generate any electricity. All of the heat generation facilities and their technical specifications in the current district heating system are presented in Table 2.1 (Göteborg Energi 2016c).

Table 2.1: Heat generation facilities in the current district heating system

	Unit	**Capacity [MW]**	**Primary Fuel**
Excess heat	Renova	185	Municipal waste
	Preem	60	Industrial excess
	ST1	85	Industrial excess
CHPs	Sävenäs CHP	110	Wood chips/Natural gas
	Rya CHP	295	Natural gas
	Högsbo CHP	85	Natural gas
Heat pumps	Rya HP 1-2	60	Electricity
	Rya HP 3-4	100	Electricity
Heat only boilers	Rya HOB1	50	Wood pellets
	Rya HOB2	50	Wood pellets
	Sävenäs HOB1	90	Natural gas
	Sävenäs HOB2	60	Natural gas
	Angered HOB1	35	Bio oil
	Angered HOB2	35	Bio oil
	Angered HOB3	35	Bio oil
	Rosenlund HOB1	140	Bunker oil
	Rosenlund HOB2	140	Bunker oil
	Rosenlund HOB3	140	Bunker oil
	Rosenlund HOB4	140	Natural gas
	Tynnered HOB	20	Fuel oil

Note that the CHP facilities also generate electricity according to their respective power-to-heat ratios (α). i.e. for each MWh of heat generated, a certain amount $\alpha * heat$ of electricity is generated. This electricity can be sold in a spot market, thus reducing the specific cost of generating heat in the CHP facility. therefore, CHP facilities are run when the market price of electricity is high and there is a sufficient heat demand. Adversely, heat pumps are run when electricity prices are low (Frederiksen et al. 2013).

2.2 Operation of the district heating system in Gothenburg

District heating networks are primarily operated after the merit order to meet the heat demand. The merit order is decided by the running costs of the generation plants where the cheapest plant is used first and more expensive plants are started as the demand for heat increases. This comes rather naturally, as the goal of the operation of the district heating system is to meet the demand for heat at a minimum total system cost (Lindholm et al. 2011).

Municipal waste CHP plants and industrial excess heat is often first in the merit order. A municipal waste CHP-plant have low running costs because it sells electricity and the plant gets paid for taking care of the city's waste. In addition to this they perform a community good by acting as disposers of waste. Industrial excess heat that is utilized in district heating systems have a running cost close to zero, since the heat would have been lost if not for the district heating utility (Lindholm et al. 2011).

The merit order decides which plant to run when and effectively has an impact on how much of different fuels that are used. In figure 2.1 the share of heat generation from different heat plants in Gothenburg is presented together with a pie chart of the amount of fuel used. (Hjalmarsson 2016)

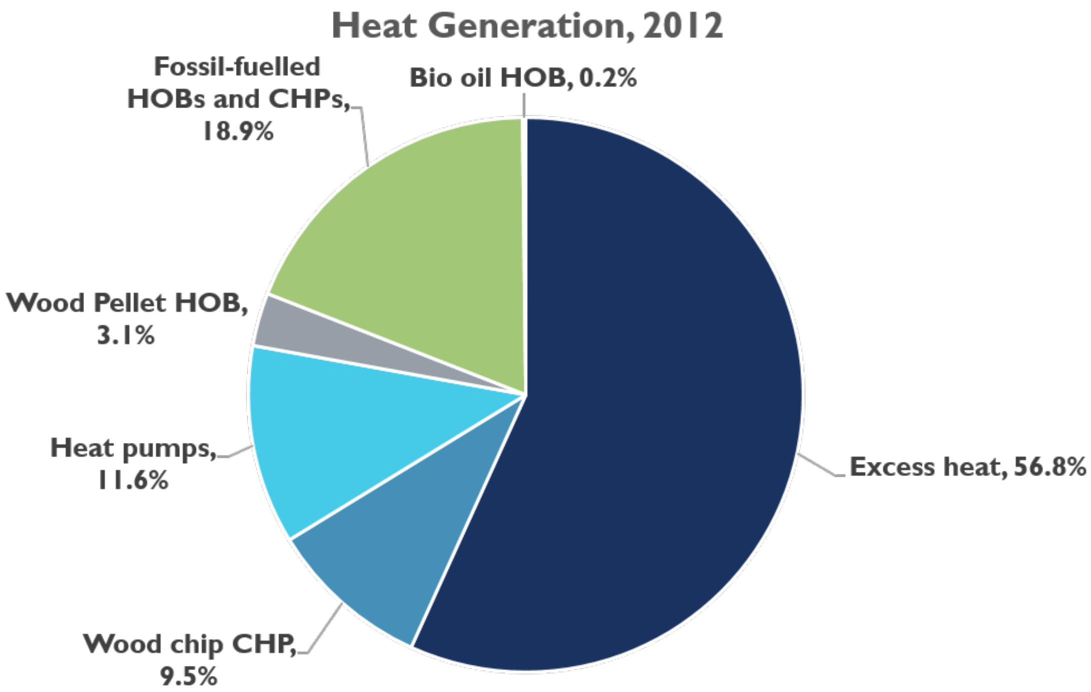


Figure 2.1: Share of heat generation per plant type and fuel used in 2012.

It can be seen from Figure 2.1 that a large portion, 57 %, of the heat generation stems from waste incineration, Renova, and industrial waste heat, ST1 and Preem. These are treated as carbon neutral for Göteborg Energi AB. By adding the proportion of heat generated from wood chips, wood pellets and heat pumps roughly 80% of the heat generated comes from sources that are carbon neutral. The rest of the heat generation in 2012, about 20 %, stems from fossil fuels. See table 2.1 for information regarding fuel and rated capacity.

2.2.1 Plans for the future district heating system in Gothenburg

Göteborg Energi have come far in terms of generating heat and power with low associated carbon emissions but the generation is not entirely free from fossil fuels. There are still some plants running as base or intermediate load, which uses natural gas and peak generation that run on bunker and fuel oil. The ambition within Göteborg Energi is that the generation of heat shall be completely free of CO_2 emissions by 2030. Several measures aimed to reduce the emissions have therefore been discussed under the initiative BioPrio (Göteborg Energi 2016a), (Göteborg Energi 2016b):

- Plants that utilize bio fuels are prioritized to a greater extent over plants based on fossil fuels.
- Thermal energy storage in a accumulator tank.
- A new bio-fuelled combined heat and power plant.
- Substitute natural gas with bio gas.

The strategy for Göteborg Energi to achieve a fossil free district heating system can be roughly divided in to three steps. The first step is to replace as large share as possible of the natural gas used in the system with bio gas. The second step involves a new bio-fuelled CHP and in the final step it is intended to replace all the remaining fossil fuel with bio gas or other renewable sources. Excess heat is considered as CO_2-free by Göteborg Energi and is projected to provide the majority of the heat in the future as well (Göteborg Energi 2016b).

2.3 Heat demand in the Gothenburg region, 2032

The future district heating generation was to be modeled for the year 2032 and one of the most crucial aspects of the simulations is the heat demand and how it will change. therefore this section will discuss the factors that affect the district heating demand on a yearly and hourly time scale and what the future development might be.

The future district heating demand will be the results of several different factors that can be grouped into four main areas (Göransson et al. 2009):

- Existing District heating customers:
  - Efficiency measures regarding buildings space and hot water heating usage.
  - Adding another heat source in buildings and share the heating between district heat and the new heat source.
  - Add a new heat source to a building that replaces the district heating.
- Existing buildings with no district heating connection that decides to invest in a district heating connection.
- District heating in new buildings.
- New applications for district heating.

The first area, existing district heating customers, includes three main factors that all have the effect of decreasing the district heat delivery. The rest of the four areas will on the contrary increase the heat deliveries as additional district heating connections to new and existing buildings together with new areas of deployment means extra heat demand for the utility companies.

A recently conducted study focused on the Gothenburg regions heat demand suggest that the total yearly heat demand will stay constant or increase by a small amount, about 2 %, by the year 2035. The authors stress that this development will mainly be a result of the construction of new residential buildings and their associated new heat demand. The new demand will balance or even offset the decrease in heat demand that stems from efficiency measures in the existing building stock.(Johnsson et al. 2016)

2.3.1 Load profile in 2032

At all times, the demand for heat must be met by generating heat in central heat generation plants in the DH system. The demand for heat, or load, in a given time step, i.e. every hour of the year, can be plotted to form a load profile. Both hot water and space heating are included in the load profile and additional hot water and space heating demand from new buildings as well as a decrease of heat demand due to efficiency measures will have an impact on the yearly distribution of the heat loads (Johnsson et al. 2016). See figure 2.2 for an example of a yearly heat load profile over Gothenburg.

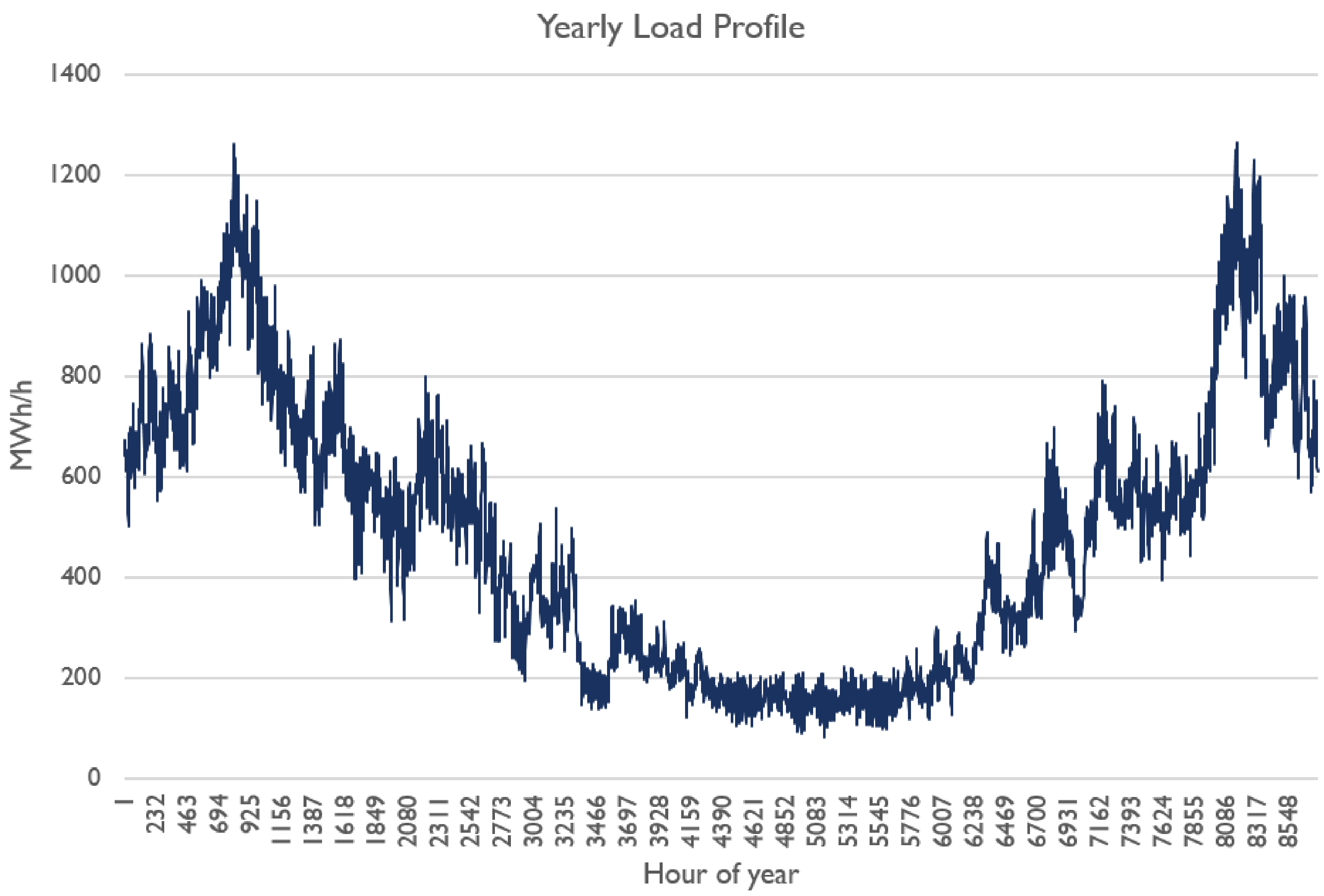


Figure 2.2: Yearly load profile of 2012

From figure 2.2 it is clear that the heat demand during summer is generally much lower than during winter and between different days significant variations in heat loads can be encountered. The difference between heat loads with respect to seasons are refereed to as seasonal heat load variation and the main contributor to this variation is the outdoor temperature which changes significantly over the year. On a daily basis the difference in heat loads are called daily heat load variations and they are mostly a result from social heat demands, which vary depending on peoples behavior (Gadd et al. 2013). Load variations increases the generating costs of the district heating system since an overcapacity of heat generation has to be available in order to meet the variations in demand at any time. By reducing the daily heat load variations the system cost of the district heating system would decrease. The advantages of less daily heat load variations are summarized in (Gadd et al. 2013) as the following:

- Less use of expensive peak load power.
- Less peak load capacity.
- Less electricity used for district network pumps.
- Improved utilisation of industrial excess heat.
- Easier to optimise the operation that leads to higher conversion efficiencies.
- Less need for maintenance because of a smoother operation of the plants.

In order to describe the daily heat load variations the relative daily variation, G_d, is used and for comparing the daily and seasonal variations the annual relative seasonal variation, D_a is calculated. The relative daily variation is the positive difference between the hourly average and daily average heat load divided by the annual average heat load and the number of hours of a day. The relative daily variation is calculated according to equation 2.1 below (Gadd et al. 2013).

$$G_d = \frac{\frac{1}{2}\sum\limits_{h=1}^{24} |P_h - P_d|}{P_a * 24} \tag{2.1}$$

P_d is the daily average heat load, P_h is the hourly average heat load and P_a is the annual average heat load (Gadd et al. 2013). The annual relative seasonal variation is defined as:

$$D_a = \frac{\frac{1}{2}\sum\limits_{d=1}^{365} |P_d - P_a|}{P_a * 365} \tag{2.2}$$

The annual relative seasonal variation is the total positive difference between the daily average heat load and the annual average heat load during a year divided by the annual average heat load and the number of days during a year(Gadd et al. 2013).

The development of the future load profile could be characterized as either more flat or fluctuating. A more flat profile means less seasonal and/or daily heat load variations and a more fluctuating profile would mean increased seasonal and/or daily load variations. Future developments that are associated with creating a more flat load profile are the implementation of different efficiency measures in buildings and new hot water demand created by future residential buildings (Johnsson et al. 2016). Efficiency improvements lower the heat losses in buildings and the required power to sustain a comfortable in-house temperature decreases. Less required space heating power will lower the demand for district heat especially during very cold hours and effectively reduce peak loads. Additional hot water demand will make the load profile more flat as the heat delivery increases over the during the summer months when there is very little space heating need.(Johnsson et al. 2016)

Factors that could increase the fluctuations are mentioned in (Johnsson et al. 2016) as buildings that implement heat pumps and reduced hot water usage due to efficiency measures. Heat pumps are usually run as base load when deployed in residential buildings and district heating often acts as intermediate or peak load, creating a more fluctuating district heat demand in buildings that previously had their whole heat demand supplied by district heating.

(Johnsson et al. 2016) states that the future load profile will probably have a more flat characteristic overall. The warmer months will have an increase in total load due to new hot water delivery and the colder months will decrease their total load because of the reduction in space heating due to higher energy efficiency in buildings.

2.4 Electricity Sector Development and Resulting Electricity Price

Today electricity consumed in Sweden is bought on the Nordic and Baltic electricity auctioning market, NordPool. There are several different ways of trading power but the main market for hourly electricity prices is the day-ahead spot market(Nordpool 2011a). The price on this market is set according to the balance between supply and demand in different regions. The price is determined by the running cost of the most expensive generating plant required to keep the power balance (Nordpool 2011b). Demand is met by first utilizing production plants with the lowest running cost and at higher levels of demand more expensive production facilities are put online. (Energimarknadsinspektionen 2014).

The actual electricity price that a consumer pays for electricity consist of more than the spot price. The spot price acts as the base price on which additional grid fees and taxes are added to. The taxes consist of a VAT and energy tax and there is also a electricity certificate that needs to be purchased when consuming electricity (Svenskenergi 2016).

Three different sets of marginal electricity cost stemming from different scenarios on the European electricity market are available for this thesis. These costs are extracted from a model at the department of Energy and Environment at Chalmers. The different scenarios are GP-green policy, RP-regional policy and CM-climate market. Below follows a short introduction that aim to highlight the differences, traits and major assumptions that define each scenario.

2.4.1 Green Policy

This scenario assumes an economic growth in the EU region and focuses on the most cost effective development on a EU-level. It focuses strongly and has ambitious goals for the environment in addition to the 2030 and 2050 emission targets. Wind power and other renewable power production are the most prevalent in this scenario and nuclear power is phased out early and does not allow any re-investments.

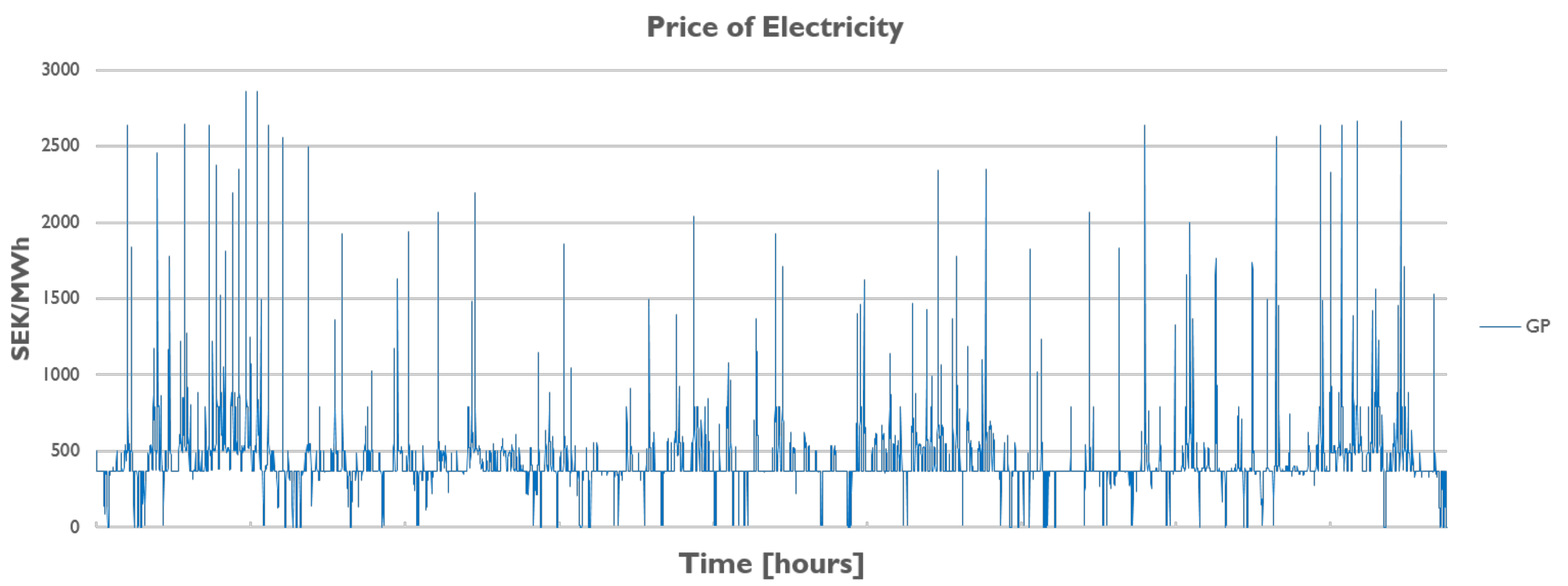


Figure 2.3: Marginal electricity cost for green policy scenario 2032.

2.4.2 Regional Policy

Regional policy, RP, has an emission trading scheme in place but it is not the only control measure for ensuring that the climate targets are met. RP has more focus on each individual country and domestic politics resulting in regional and national specific policies such as taxes and incentives. The economic growth rate in the EU is slower compared to GP and CM scenarios.

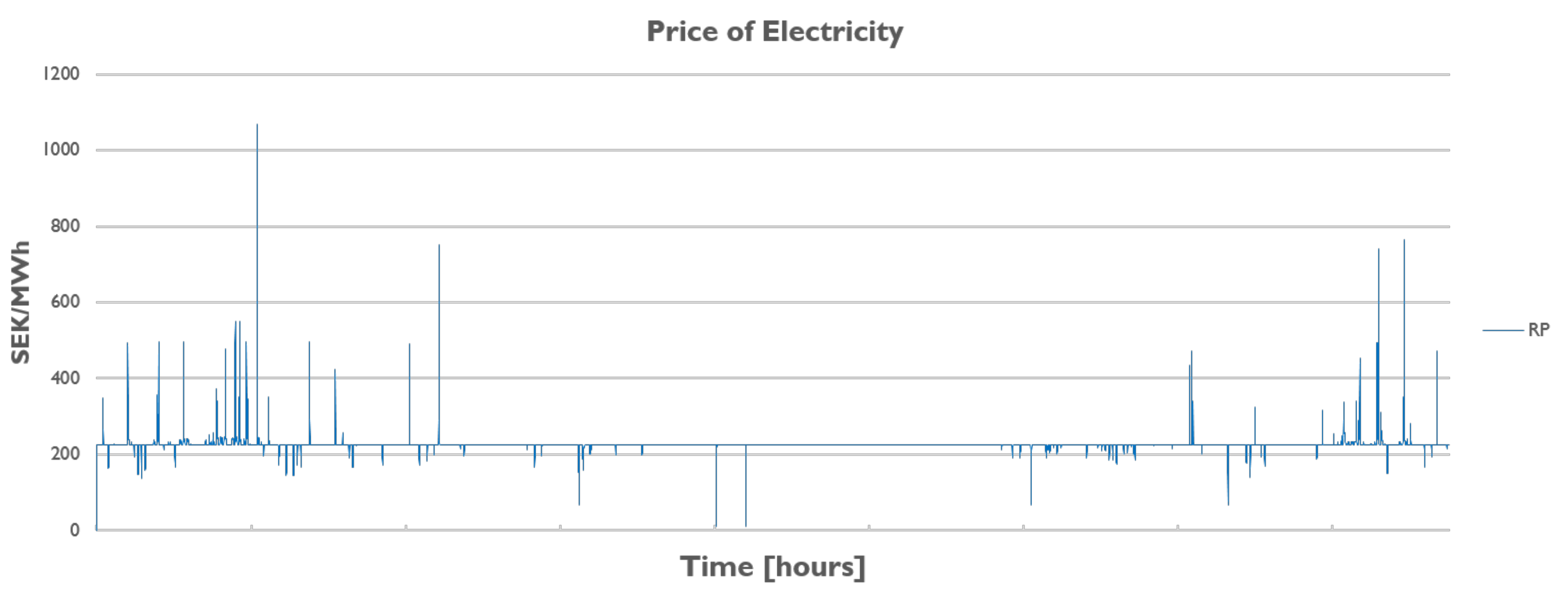


Figure 2.4: Marginal electricity costs for regional policy scenario 2032.

2.4.3 Climate Market

The climate market scenario, CM, is a strictly economical scenario that meets the climate targets in the EU for 2030 and 2050 by only using a emission trading scheme on EU level. There is only going to be one effective price for CO2-emissions in the whole of EU since no competing schemes or policies in any region are in effect after 2020. The scenario assumes a growing economy until 2050 and nuclear power production is allowed.

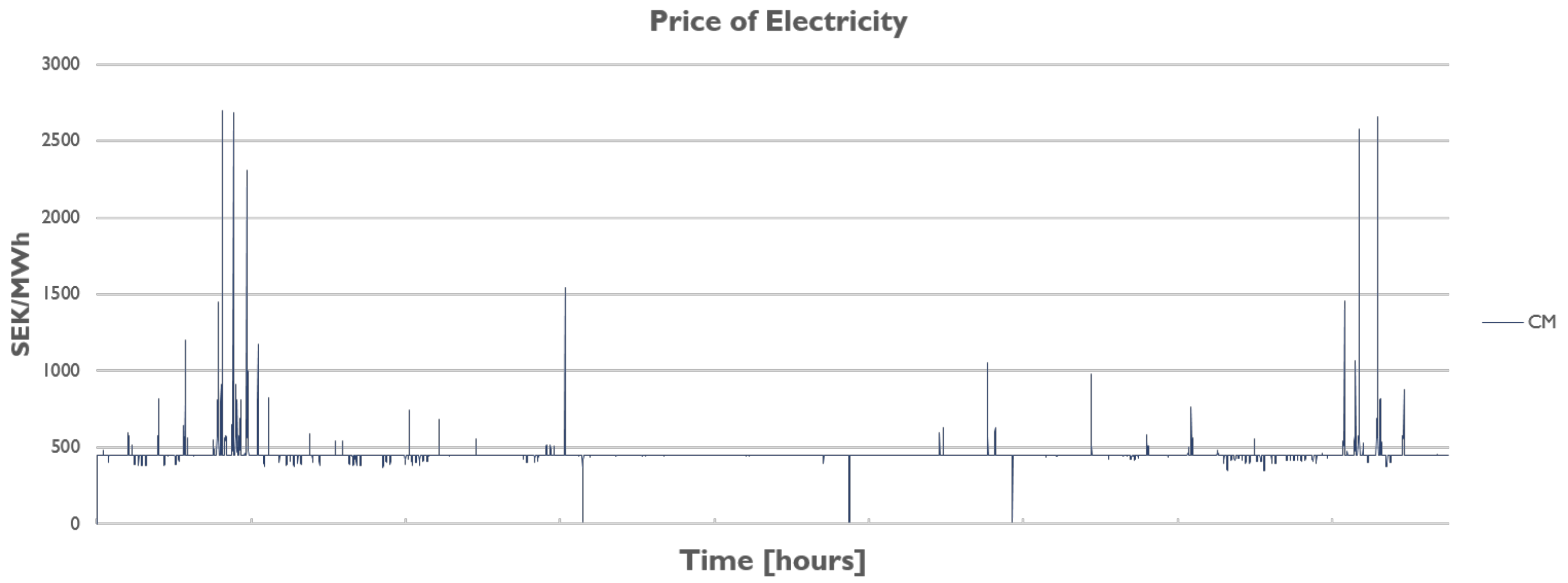


Figure 2.5: Marginal electricity cost for climate market scenario 2032.

From the figures above it is evident that the different electricity scenarios have certain characteristics and average price levels. The distribution diagram of the scenarios can be seen in figure 2.6 and is helpful in visualizing the average levels of the different electricity scenarios.

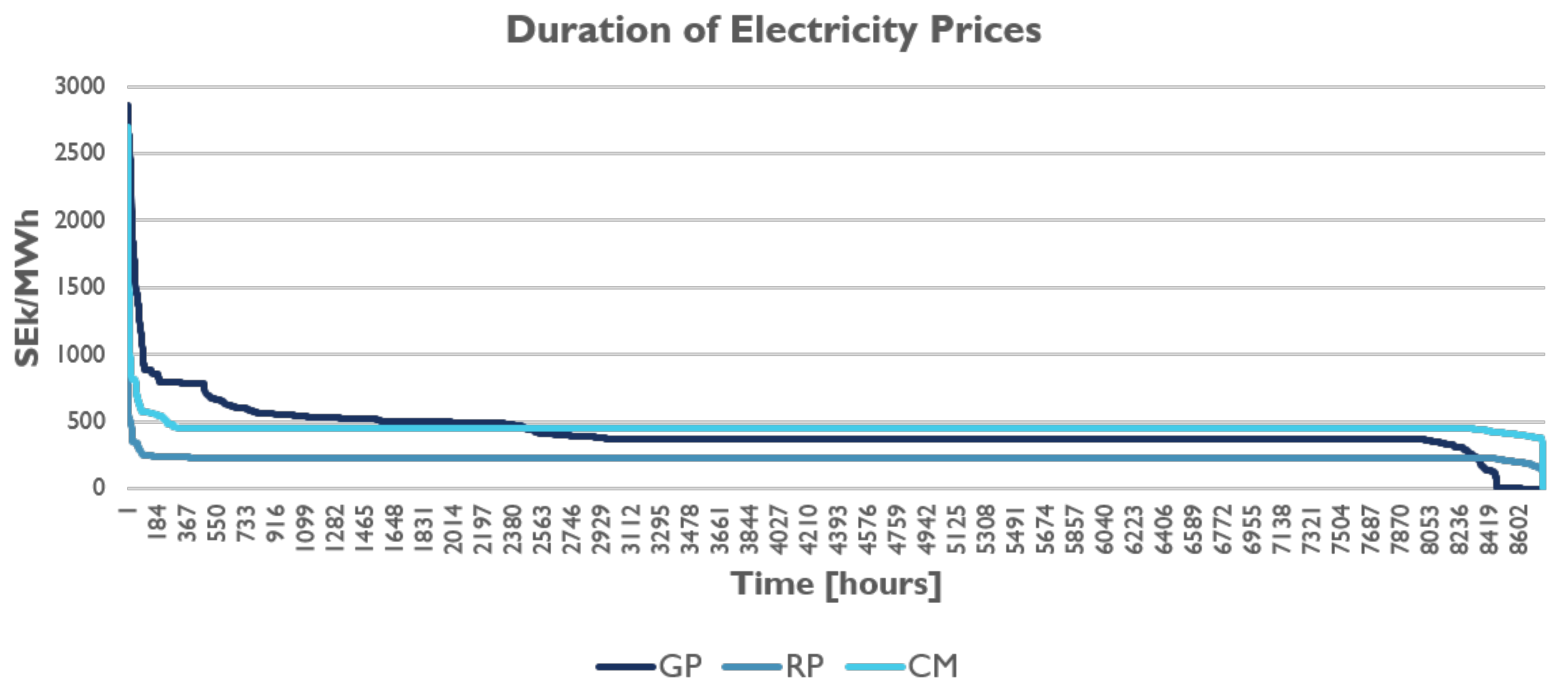


Figure 2.6: Distribution diagram of the three electricity scenarios; GP,RP and CM.

It can be seen in figure 2.6 that the three scenarios have different average marginal costs. The GP case has the highest costs but also most hours with basically zero cost of electricity. RP has the lowest average cost and also the most stable costs. CM is in between GP and RP case with a higher average cost than RP but lower and more stable prices than GP. The fluctuations of the electricity costs can be seen in the figures above and also table 2.2 presents the standard deviation of the electricity scenarios giving an indication of how fluctuating the prices are.

Table 2.2: Standard deviation of marginal cost of electricity

El.-scenario	GP	RP	CM
Mean el. cost [SEK/MWh]	424	226	452
yearly, std-dev [SEK/MWh]	200	23	68
mean of daily std-dev [SEK/MWh]	120	8	18

2.5 Thermal energy storage (TES)

The future energy system, including both electricity and heat, is likely to become more intermittent than the current system. This intermittency stems from the increased share of renewable energy sources in the system such as wind and solar power (Averfalk et al. 2014). The district heating sector is to a high degree affected by this development mainly through the synergies that exist because of i.e. heat pumps and CHP plants (Sköldberg et al. 2015). This intermittent behaviour means that the generation of renewable energy does not always match the demand for energy, and fossil-fuelled and expensive plants may have to be put in to operation when there is not enough energy being generated by renewable sources, which is neither economically nor environmentally optimal. In order to avoid these situations, a large number of measures are currently being discussed which, among others, include thermal energy storage (TES) and demand response (Heier 2013). Thermal energy storage can aid in reducing the peak generation of heat by storing heat during hours with lower demand (and cost of generation) and then discharge during high-demand hours. An additional beneficial function of TES is to allow for increased electricity generation in CHP plants, where the TES can function as a heat sink, when there is no demand for heat (Frederiksen et al. 2013). Demand response can give system benefits by shifting the load from high-demand hours to hours with a lower demand, thereby making it possible to avoid the use of peak load covering plants and avoiding starts and stops in base load plants (Nyholm et al. 2014).

The demand for heat in a DH system can fluctuate heavily during the course of a day. Figure 2.7 shows the generation of heat by Göteborg Energi during the first week of 2012. The generation of heat can differ by as much as 200 MW in a time period of less than 12 hours during this week. The demand for heat depends on a number of factors such as outdoor temperature, time of day and whether or not people are working (Dotzauer 2002). In order to meet the varying demand, many starts and stops are required from e.g. boilers, which have a decrease in efficiency and increase of heat losses when run in this way. A possible measure to even out the variations in demand is to implement a thermal energy storage. The storage would then be charged with heat during hours with lower demand and be discharged during peak demand hours, effectively levelling out the demand for district heat (Heier 2013).

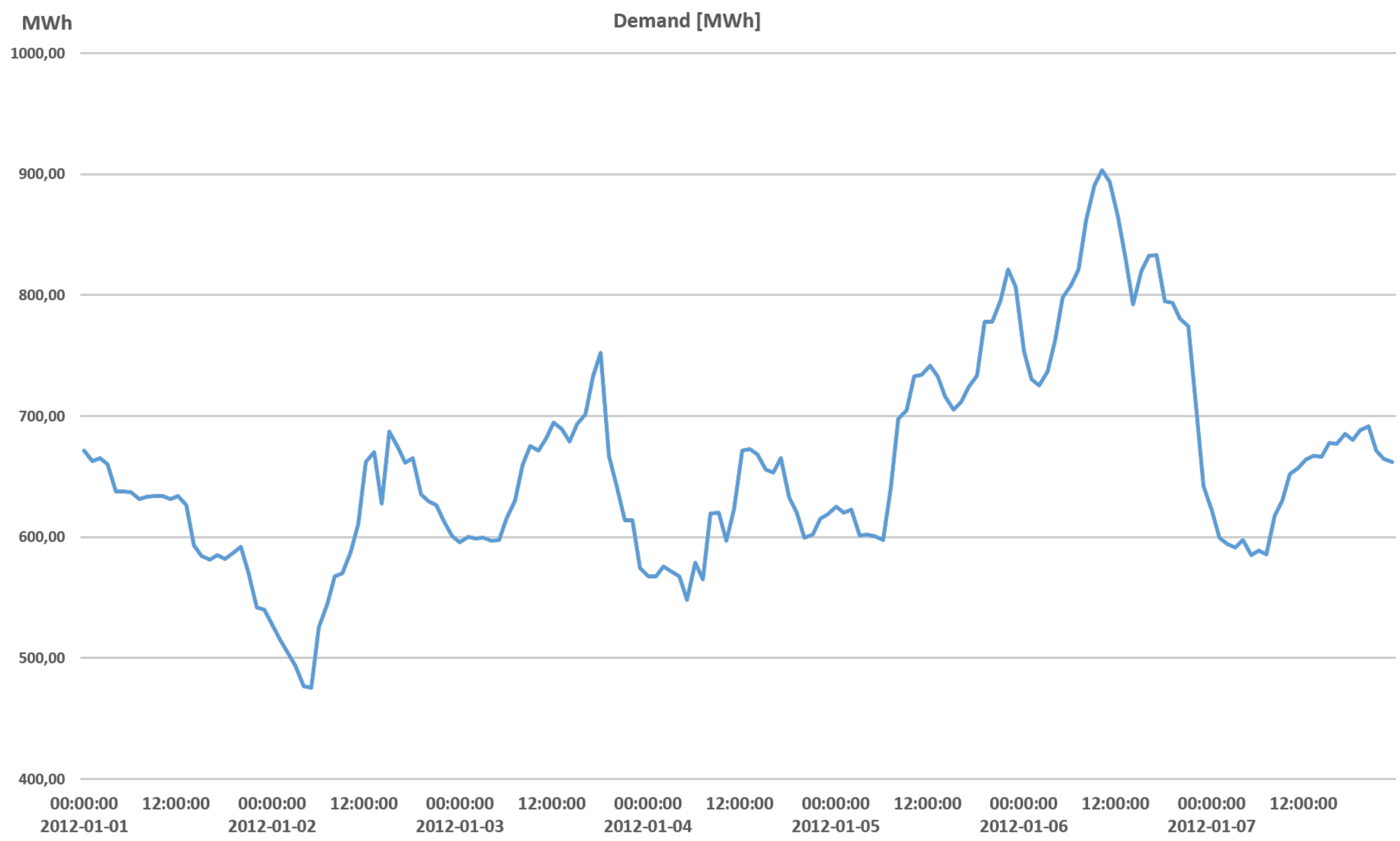


Figure 2.7: Generation of district heat during the first week of 2012

TES can be divided into two categories, depending on which timescale they are intended to be used. *Short term* energy storage is charged and discharged in cycles that can span from an hour to up to a week. *Long term* energy storage instead has a time horizon that is longer, up to an entire year in some cases (Schäfer et al. 2012). Short term TES usually have a lower energy storage capacity but higher charge/discharge power, compared to long term TES. Long term TES on the other hand have large energy storage capacity with low relative energy losses (Frederiksen et al. 2013).

Examples of short term TES technologies include (Dincer 2002), (Kensby et al. 2015):

- Rock and earth beds
- Hot water storage tanks
- Phase change materials
- Utilizing building thermal inertia

Long term TES technologies include (Nordell 1994):

- Underground cavern storage
- Aquifier storage
- Duct storage
- Borehole storage

In this thesis, the possible implementation of a hot water storage tank, utilizing building thermal inertia and an underground cavern storage is investigated. These alternatives are considered as plausible in the Gothenburg Energy system and are described in the following sections (Hjalmarsson 2016).

2.5.1 Thermal Energy Storage in Hot Water Accumulator Tank

A widely used type of short term thermal energy storage is a hot water accumulator tank, which is charged with hot water directly from the supply line of the DH system and then discharges hot water back to the supply line when needed. The benefits of a hot water accumulator in a DH system have been widely discussed in literature, see e.g. (Verda et al. 2011) and (Bogdan et al. 2006). As in the case with all thermal energy storage, the accumulator tank is charged with hot water when the cost of generating heat is low, and the storage is discharged when the cost is high.

An accumulator tank is most often constructed in steel with an insulation layer surrounding it. The tank is equipped with connections to the district heating network at its top and bottom, where the charging and discharging of hot water takes place. Figure 2.8 shows the working principle of a typical accumulator storage system (Frederiksen et al. 2013).

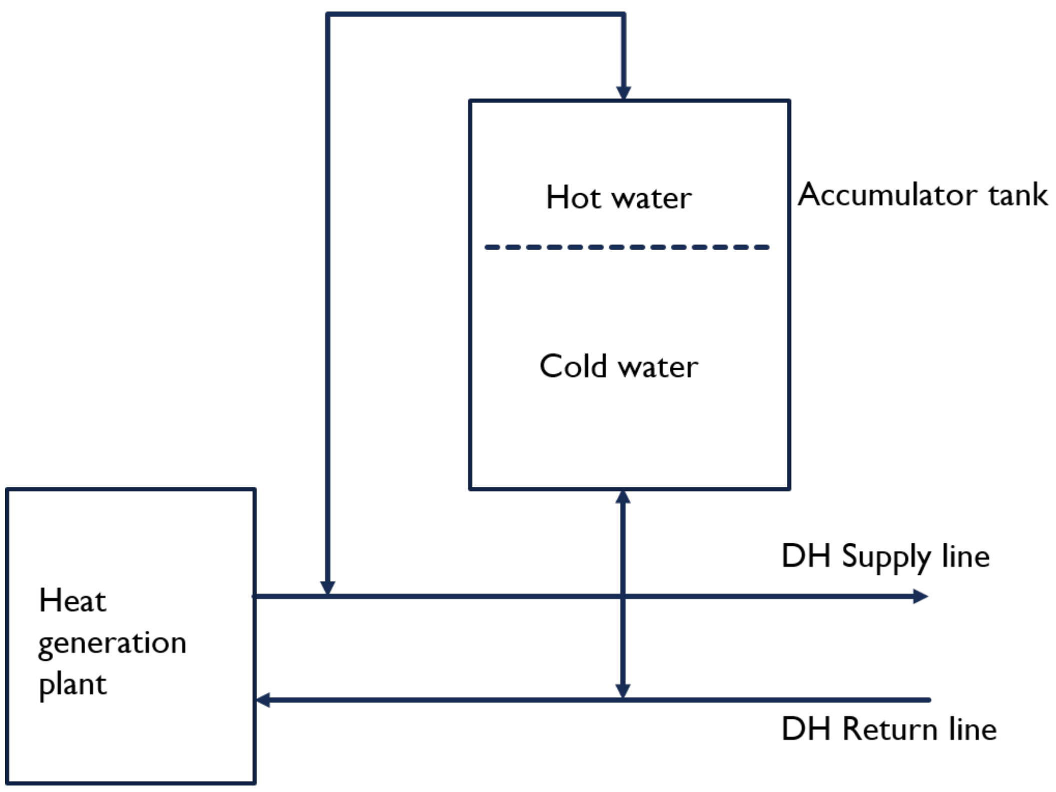


Figure 2.8: Working principle of accumulator tank storage

Accumulator tanks can be constructed as either *pressurized storage tanks* or as *atmospheric pressure storage tanks*. A pressurized storage tank is used when the temperature of the hot water is higher than 100°C and the pressure in the tank corresponds to the pressure of the district heat network. Pressurized tanks require steel of pressure-vessel grade. An atmospheric pressure tank is cheaper, since no pressure-vessel grade steel is required, but the maximum temperature of the hot water is restricted to approximately 100°C. In Sweden, atmospheric pressure storage tanks have been used for a number of years (Frederiksen et al. 2013).

Because of the density difference between hot and cold water, hot water will rise to the top of the accumulator tank and cold water will sink to the bottom. At the boundary between the hot and cold water volume, there will be a drastic change in temperature, which is called a thermocline transition layer. This phenomenon is referred to as stratification and is an important aspect of TES in water volumes. The distinct difference in temperature is helpful when discharging the storage, since water with the desired supply temperature is available at the top of the tank. If the water is stirred or mixed, the thermocline is broken up and the temperature profile of the water gets more uniform, meaning that the hot water will be colder and the cold water will be warmer (Berkel et al. 1999).

An accumulator will experience losses in the form of energy and exergy. Energy is lost through the perimeter of the tank to the surroundings and the exergy losses are due to the above described mixing of hot and cold water (Steen et al. 2015). The energy losses arise due to the fact that the water inside the tank have a higher temperature than the surroundings, resulting in a net transport of heat from the water to the surroundings. This heat transfer can be described by the following equations (Incropera et al. 2013):

$$\dot{Q}_{loss} = \frac{T_{tank} - T_{surr}}{R_{tot}} \tag{2.3}$$

Where T_{tank} is the average temperature of the water inside the tank, T_{surr} is the average ambient temperature and R_{tot} is the total heat transfer coefficient of the tank walls. R_{tot} includes conduction through the steel wall and its insulation layer as well as convection on the interior and exterior of the tank wall. R_{tot} depends on the materials used, their thickness and the surface area of the tank. The exergy losses are more difficult to approximate and are usually neglected when modelling TES (Steen et al. 2015).

(Steen et al. 2015) developed an approach that approximates the losses of an accumulator tank, which is suitable to use in a simulation model. In short, the total losses from an accumulator tank can be described by the expression:

$$E_{loss} = E_{stored} * \phi_{storage} + E_{unuse} * \phi_{static} \tag{2.4}$$

Where E_{loss} is the energy lost per time step, E_{stored} is the amount of energy that is stored in the tank at any given time step. $\phi_{storage}$ is a loss coefficient that is related to the energy lost to the ambience. E_{unuse} is the energy in the water volume that holds a temperature that is below the lowest temperature that is usable in the DH system. This water volume will give an additional loss to the surroundings, which is described by the static loss coefficient ϕ_{static}. In their article, (Steen et al. 2015) set these two loss coefficients as $\phi_{storage} = 0.060\%$ and $\phi_{static} = 0.053\%$. It should be noted that these figures are highly specific for a certain accumulator tank, and temperature levels.

In addition to act as a storage in the sense that has been previously described, an accumulator tank can provide benefits as a local heat generation plant in areas where the district heating network capacity is too low. For example, in some branches of the Gothenburg district heating network, the distribution capacity in the pipes is too small and local heat-only boilers are put in to operation, which is not cost efficient. By placing the accumulator strategically, one can provide these branches with stored heat that was generated at a lower cost (Sommansson 2016).

The active volume in a water accumulator tank required for a given amount of energy to be stored can be calculated according to (Incropera et al. 2013):

$$V_{acc} = \frac{E_{acc}}{\rho_{water} c_{p,water} \Delta T_{water}} \tag{2.5}$$

Where E_{acc} is the amount of energy (in Joules), ρ_{water} is the density of water in the working temperature interval. $c_{p,water}$ is the heat capacity of water per kg. ΔT_{water} is the temperature difference between the hottest water in the tank and the coldest. The highest temperature in the tank would be equal to the district heating supply temperature at around 80-100°C and the lowest is equal to the return temperature of the DH system, i.e. 30-50°C (Hjalmarsson 2016). It should be noted that for construction and operational purposes, the volume calculated above is increased somewhat in reality (Skogfält 2009).

The investment cost of an accumulator includes the cost of the tank itself, installation costs and costs associated with the connection of the tank to the DH network. (Skogfält 2009) gives, based on previously installed accumulator tanks in Sweden, an expression for a rough estimation of the construction and installation costs of an accumulator tank. The construction costs are approximated by:

$$C_{Acc} = 1.66 * 10^7 * ln(V_{Acc}) - 1.39 * 10^8 \tag{2.6}$$

Where C_{Acc} is the construction cost in SEK and V_{Acc} is the actual volume of the accumulator tank in m^3. The installation costs are approximated by:

$$C_{Inst} = 157 * V_{Acc} + 6\ 000\ 000 \tag{2.7}$$

Where C_{Inst} is the installation costs in SEK. The costs for connecting the tank to the DH network is very hard to approximate since they depend heavily on the circumstances fro each tank and DH network. The costs described above can however be used as a minimum cost for preliminary calculations. The cost of construction and installation is presented as a function of the actual volume V_{Avv} in Figure 2.9

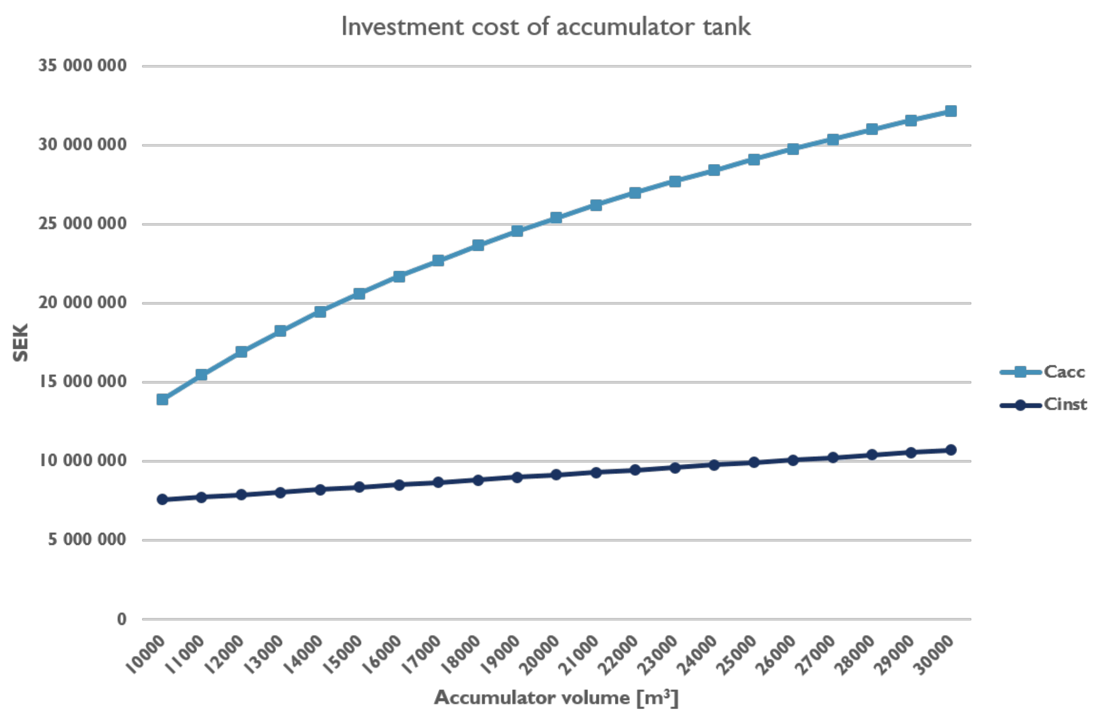


Figure 2.9: Construction cost C_{Acc} and installation cost C_{Inst} of accumulator tank

2.5.2 Thermal Energy Storage in Buildings

Another way of implementing short term thermal energy storage is to utilize the existing building stock itself as storage. This approach has been investigated by (Kensby et al. 2015) among others. In hours with low demand, one can increase the indoor temperature in a building by increasing the heat transferred from the DH network during a certain period of time. Once the heat delivery is decreased again, the temperature inside the building does not decrease immediately. This is because the building has a thermal inertia, heat is stored in the air inside the building and in the building materials themselves as well as in the fluid inside the radiator system of the building.

Heat is delivered from the DH system to a building through a heat exchanger that exchanges heat between the DH network and the heating system of the building. The heating system of the building is usually a radiator network with water as working fluid. The indoor temperature of the building is changed by changing the supply temperature to the radiators in the radiator system. The flow of water in the radiator system is kept constant and the way that radiator temperature is changed is by adjusting the flow of DH water in the DH heat exchanger. These adjustments are made via a control system, which is adjusting the flow of DH water in order to achieve a set radiator system temperature (Frederiksen et al. 2013). See Figure 2.10, where the principle of controlling the supply temperature to a radiator system is shown. The set point for the radiator system is often set as a function of the outdoor temperature. By lowering this set point, more heat is needed from the DH system and vice versa. When making such changes, the room temperature responds dynamically, depending on various factors such as building materials, solar insolation and so forth (Johansson et al. 2010a).

As an example, one can assume that the standard set point is an indoor temperature of 20°C. The building can then be said to be charged with heat when the indoor temperature rises to say, 21°C. The building is subsequently discharged when the indoor temperature slowly decreases towards the set point temperature, or even below it. A simple and cheap way of implementing TES in buildings is to add a temperature control signal to the radiator set point mentioned above. This is explained by an example: assume that the radiator set point is 40°C at an outdoor temperature of 4°C, which in turn gives an indoor temperature of 20°C. Now, if one wants to charge the building, one could add a temperature control signal to the outdoor temperature signal. A charge signal would then mean that e.g. 7°C is subtracted from the outdoor signal, and the radiator set point would increase. Subsequently, the indoor temperature would increase over time, and the building TES is charged with heat. To discharge, one instead adds the 7 °C to the outdoor signal, and the heat delivered from the DH network is decreased. This strategy was described and used by (Kensby et al. 2015) and (Johansson et al. 2010a). Figure 2.10 shows this principle, where Δu denotes the temperature control signal. u is the original control signal used, which is linearly related to outdoor temperature.

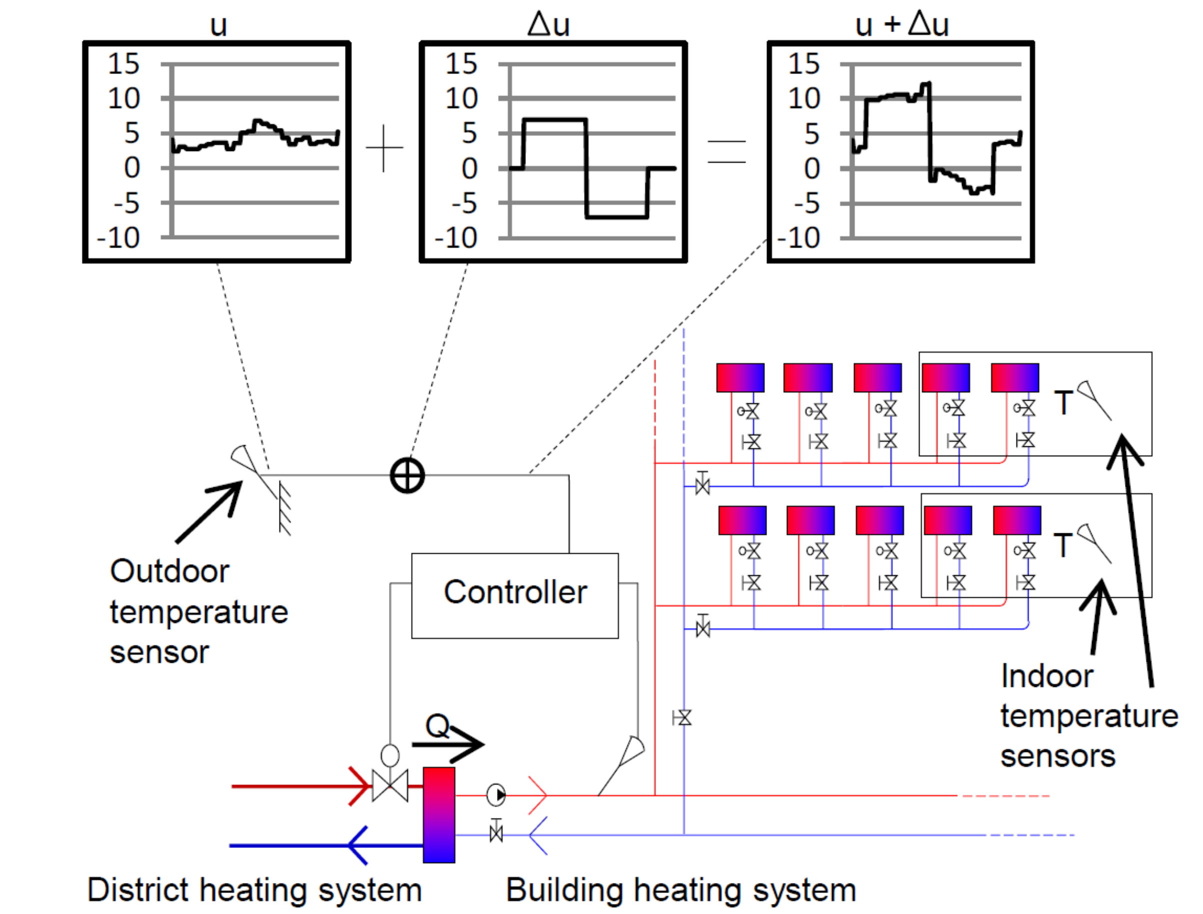


Figure 2.10: Principle of control system for utilizing buildings as thermal energy storage. Image source (Kensby et al. 2015)

The concept of utilizing the building stock as thermal energy storage have been investigated and evaluated in a number of previous studies. The studies show that building TES have large potential for both total energy savings and peak load reductions. A pilot study in 2003 in Finland showed that peak heat demand could be reduced by 20-25% during 2-3 hours in a residential building in Finland with an acceptable drop in indoor temperature (Kärkkäinen et al. 2003). Another pilot study conducted in three large DH systems in Sweden resulted in peak load reductions of 15-20% and an overall energy reduction of 7.5% (Johansson et al. 2010b).

In these studies, the indoor climate in the tested buildings was studied and used as a means to measure the potential of storage and power capacity of the buildings. The indoor climate is the main limiting factor for heat storage, since the dwellers of the buildings will experience discomfort if the building is heated too much or too little.

In two studies, (Kensby et al. 2014) and (Kensby et al. 2015), it was investigated how much one can use a building to store heat without causing thermal discomfort for the dwellers of the building, and how the indoor temperature relates to the changed heat load. Through pilot studies and simulations, the control strategy described earlier was evaluated and the results were used to estimate the heating power capacity and heat storage capacity of the building stock of Gothenburg. A temperature control signal of ±7°C was used and it was found that it could be added to the regular control signal for a maximum of 9 hours before the indoor temperature variations became too large. By multiplying the 7°C with 9 hours one gets 63°Ch, which is a measure of how much heat a the building type studied in (Kensby et al. 2014) is able to store. The ±7°C can be seen as a measure of the heating power capacity that is available when using a typical building in Gothenburg as thermal energy storage.

The buildings in the residential area Västra Gårdsten in Gothenburg were mainly constructed during the 1960s and 1970s and are very similar to the buildings that were used as a case study for the studies described above. Also, there are many buildings in Gothenburg that resemble the building stock in Västra Gårdsten. therefore, in (Kensby et al. 2014), the area of Västra Gårdsten was used to asses the potential of heat storage buildings on a larger scale. The area of Västra Gårdsten, which has an average annual heat consumption of 12.1 GWh, has a power signature of 0.13 MW/°C. This means that for a decrease in outdoor temperature of 1 °C, the required heating power increases by 0.13 MW. Since the temperature control signal described earlier had a maximum value of 7°C, the maximum heat power that can be used to charge or discharge TES in buildings is $0.13MW/°C * 7°C = 0.91MW$. The maximum storage capacity would similarly be calculated using the power signature and 63°Ch that were described earlier as $0.13MW/°C * 63°Ch = 8.19MWh$. These result were then used to asses an even larger implementation of building TES in Gothenburg. If 20% of the DH substations in Gothenburg were to be used to control buildings as TES, the total power capacity would be 63 MW and the maximum storage capacity would be 571 MWh.

An important result from (Kensby et al. 2015) is that the variation in indoor temperature when changing DH supply power to a residential building depends on two main interacting components in a buildings thermal inertia. These two components are the indoor air and surfaces in apartments and the structural core in the building. The indoor air has a smaller thermal mass than the solid materials and will change temperature faster when the heat from the DH system is changed. The structural core shows a slower change in temperature because of its larger thermal mass. therefore, one can refer to these two components as a *shallow/fast* and *deep/slow* storage when describing TES in buildings.

These dynamics, and their effect on a control system in a building were the topic of a master's thesis during 2016 (Carlsson 2016). The correlation between the shallow and deep storage were examined, and the charge rate depending on outdoor temperature was also studied. It was found that the charge rate, meaning how much heat in MW, that is available depends on the outdoor temperature as follows: maximum charge rate is achieved at outdoor temperatures below 8°C and the charge rate is effectively zero at outdoor temperatures of 15°C or higher. The charge rate decreases linearly between these two temperatures. The relation between the deep and shallow storage can, highly simplified, be described as two storages connected in series with each other. The shallow storage is charged and discharged to and from the DH system. The deep storage is charged and discharged from the shallow storage. See Figure 2.11 for a principle sketch of how the two storages interact.

The rate at which the two storages charges and discharges each other, $\dot{Q}_{deep}$ in Figure 2.11, depends on the state of charge of the two storages. State of charge can in this case be measured in temperature and be translated to Wh through multiplication with the density, volume and specific heat capacity of air and building materials. If, for example, the deep storage has a higher state of charge (temperature) than the shallow storage does, heat will flow from the deep storage to the shallow storage and vice versa.

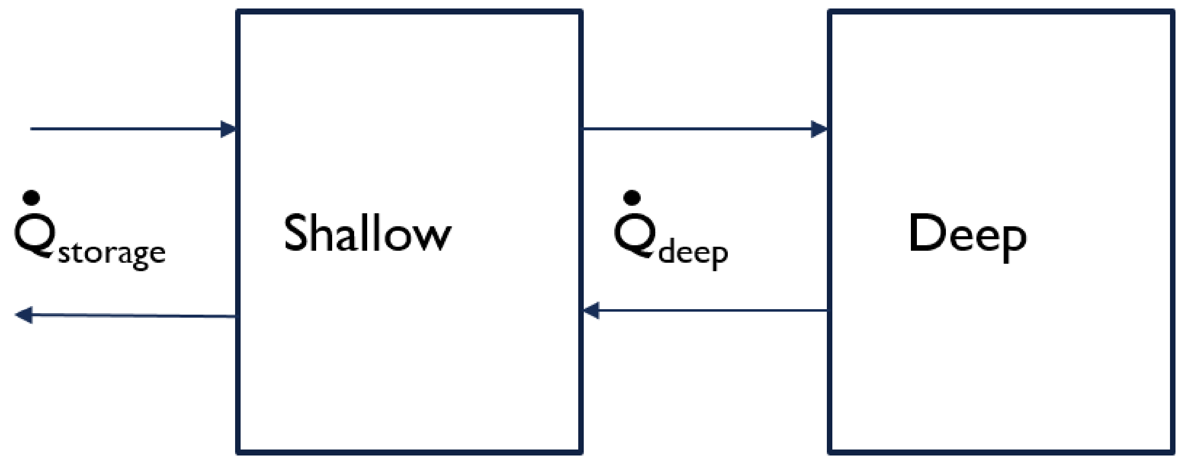


Figure 2.11: Principle sketch of building thermal energy storage

One aspect associated with thermal energy storage in the building stock that differs from most other TES technologies is that the storage medium is already present in the DH system. The buildings already exist and the only investment needed is that of control systems that controls the periodic overheating and under-heating of the buildings (Kensby et al. 2015). This is a major advantage compared with other, traditional TES technologies. A drawback is that one would need the consent of the inhabitants of the residential buildings to control their indoor temperature. The estimated installation cost for this is in the range of 24,000 SEK or less per DH substation (Kensby 2016). The 500 largest DH substations in Gothenburg stand for roughly 20% of the annual heat generation in Gothenburg (Kensby et al. 2014).

2.5.3 Seasonal Thermal Energy Storage

During the warmer periods of the year, the amount of excess heat that is generated in the oil refineries and waste incineration plant in Gothenburg exceeds the total demand for district heating in the system. This is clearly shown in Figure 2.12 below, where the demand during the period May through August of 2012 is plotted together with the possible maximum output from the excess heat generators ST1, Preem and Renova during the same period.

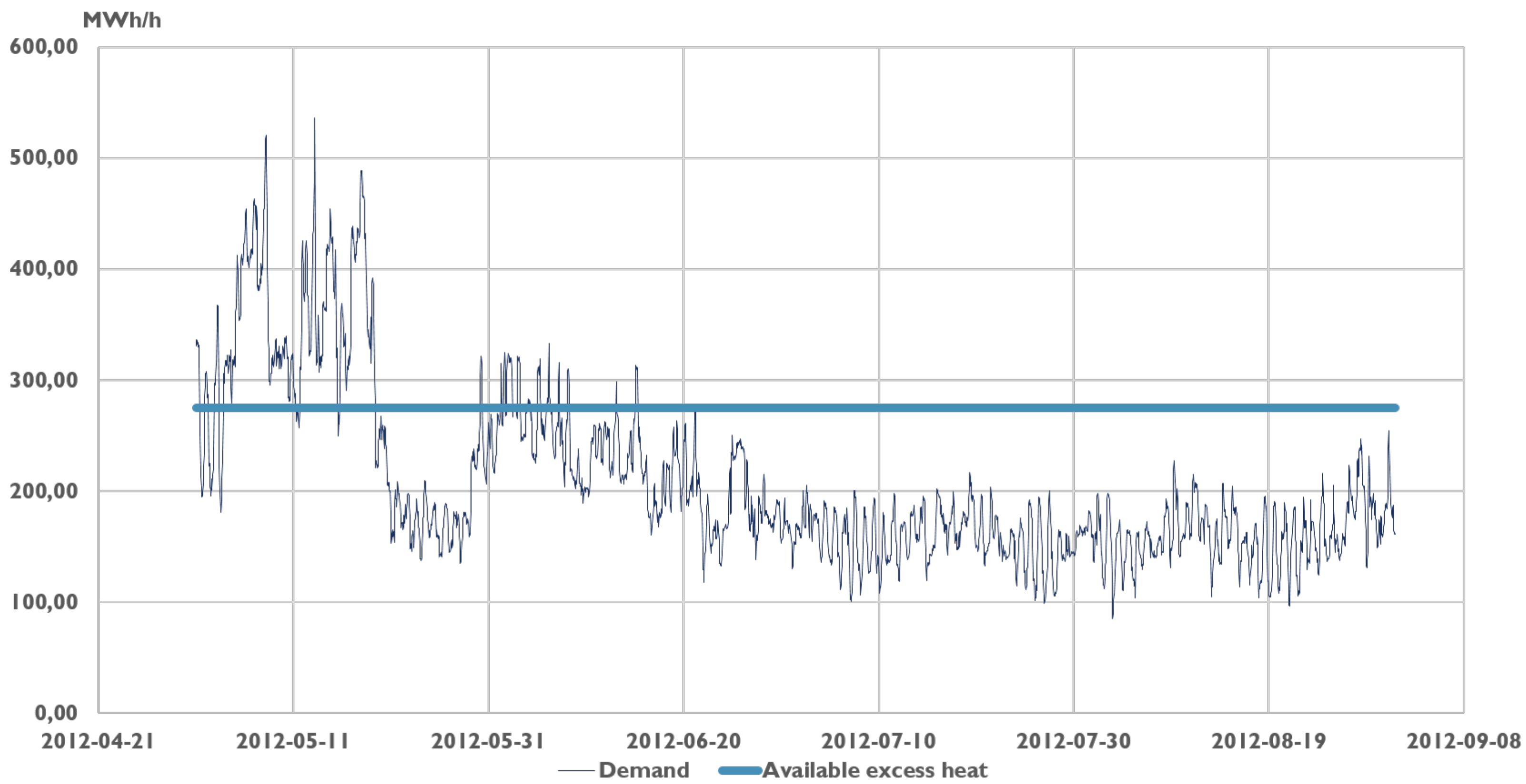


Figure 2.12: Demand for heat and available excess heat, May-August 2012

At times when the generated heat from the excess heat sources exceeds the demand for district heating, either the output from the excess heat plants is reduced, or heat is cooled against the environment, e.g. in chimneys or to a river (Hjalmarsson 2016).

Instead of cooling this free, excess heat, one could make use of it by storing it until times when the demand for district heating is higher and thus acquire savings in both monetary terms as well as environmental since the operation of peak load plants during winter can be replaced by the stored heat from summer (Zinko et al. 2008). In Gothenburg, one study showed that during 2013, approximately 100 GWh of heat was cooled off (Hallqvist 2014).

The amount of energy that has to be stored is thus very large, and in addition these amounts have to be stored for a long period of time. therefore, the storage will have to be large in terms of volume and as a consequence have a very high investment cost, depending on the storage medium. Generally, a free storage medium such as rock, soil or water is used in these situations (Zinko et al. 2008). As pointed out in (Nordell 1994), in large seasonal thermal storage, the daily heat losses must be low, since the duration of the storage period is long. In order to achieve an inexpensive heat storage with low relative heat losses, the storage is usually placed underground.

One such underground storage is a so called cavern thermal energy storage (CTES). In CTES, a large water volume is stored underground in enormous rock formations, either natural or man-made. The water is used as a heat carrier (together with the surrounding rock) and is thus used as a energy storage (Lee 2013). One great advantage with CTES, when compared with other large scale underground storage technologies, is that the charge/discharge power can be very large (Nordell et al. 2007). A disadvantage is the high costs that comes with excavating a large cavern underground.

In Sweden, the concept of storing heat underground is not novel. Since the 1950s, petroleum products have been stored in large caverns underground. Some of these caverns could be reconstructed as thermal energy storage, decreasing the initial investment cost of the storage. There are around 140 such petroleum storage in Sweden, and much of the knowledge about CTES stems from the construction and management of these petroleum storages. The typical depth of the caverns is between 50-200 m, and the volume of them ranges in between 50 000 m^3 to 2 000 000 m^3 (Zinko et al. 2008).

Figure 2.13 shows the principle sketch of a CTES that was constructed in 1983 in Lyckebo outside of Uppsala, Sweden. The Lyckebo CTES has a storage volume of 100 000 m^3 and is built as a thoroid (Brunström et al. 1987). The figure shows one of the main principles for a CTES, where hot water is pumped in or out from the storage near the roof of the cavern and colder return water is injected at the floor of the cavern (Åström 2011). This principle is similar to that used in accumulator tanks and ensures that hot supply water is always available for extraction, as the warmer water with lower density rises towards the top of the water volume (Pinel et al. 2011).

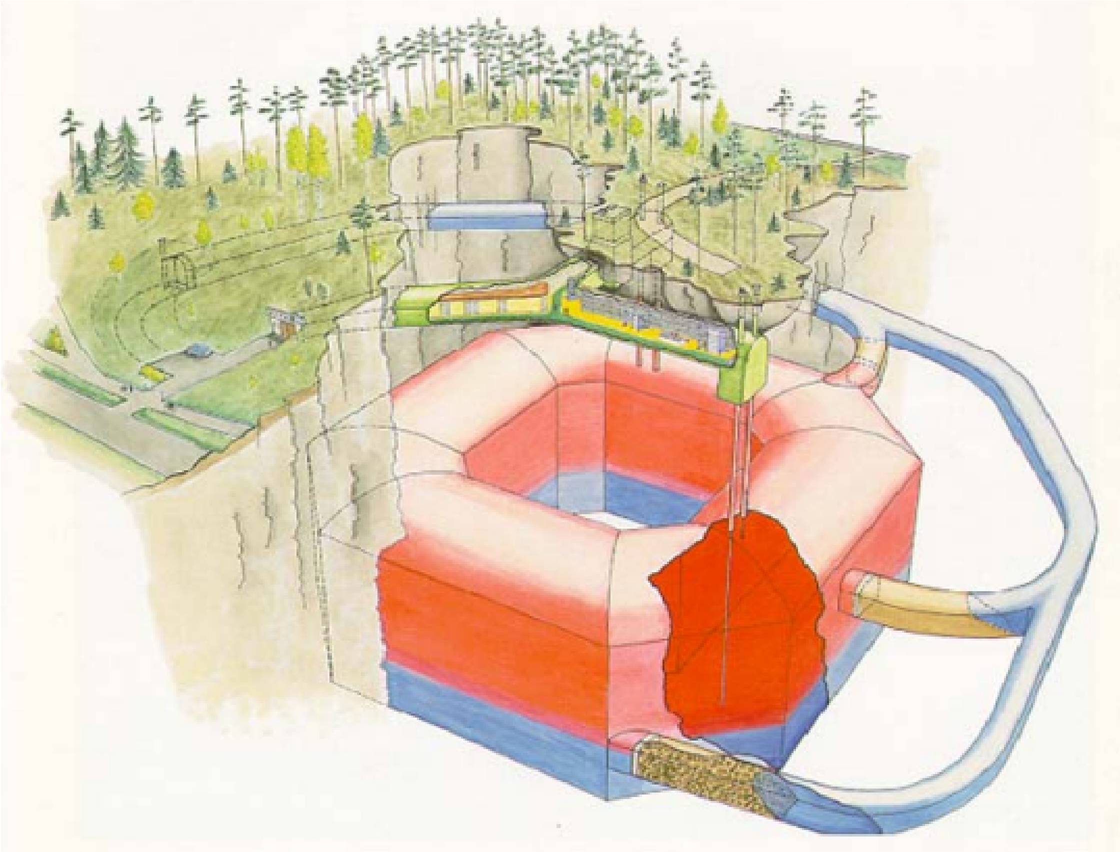


Figure 2.13: The Lyckebo CTES system. Image source: Nordell et al. 2007

The heat losses from a CTES occur through the perimeter area of the water volume. The temperature of the rock at a depth of around 15-20 m is the same as the yearly average air temperature at the location, and the losses occur when the temperature of the water decreases because it heats the surrounding rock (Nordell 1994). For a specific increase in storage volume, the perimeter area increases less, since volume increases with m^3 and area with m^2. therefore, with a larger storage volume, the *relative* heat losses from the storage are smaller (Lee 2013). It is in general very hard to predict the heat losses of a CTES, since they can be affected by the local conditions in the rock at which it is situated. This was the case in Lyckebo, where cracks in the rock made it possible for water to circulate and create so called internal heat losses (Brunström et al. 1987).

In order to roughly estimate the volume of the storage, one can use the following equation (Incropera et al. 2013):

$$E_{CEST} = V_{CEST} * c_{p,water} * \rho_{water} * \Delta T_{CEST} \tag{2.8}$$

Where E_{CEST} is the amount of energy that is able to be stored, V_{CEST} is the water volume of the storage, $c_{p,water}$ is the specific heat capacity of water, ρ_{water} is the density of water and ΔT_{CEST} is the average temperature difference in the storage, i.e. the difference between supply and return temperature of the storage. For district heating purposes, this temperature difference is usually around 50°C (Hjalmarsson 2016). Zinko et al. 2008 uses a similar approach, with some modification to calculate the needed volume. They reference Pilebro H. and state that 1 MWh of storage capacity requires 20 m^3 of storage space in a CTES.

The heat losses from a CTES are initially substantial, since it takes time for the hot water to heat up the surrounding rock, which has a lower heat capacity than water. This heating period stretches over several seasons, and after approximately 5 years the losses have reached a steady-state level (Brunström et al. 1987). In the Lyckebo CTES, the losses from the storage during its first year of operation were 4000 MWh, 14 years later, they were 1000 MWh (Åström 2011). Typically, the relative yearly steady-state losses for a CTES are around, or below 10% (Lee 2013).

As mentioned, the investment costs of excavating a cavern for CTES are large. (Zinko et al. 2008) presents a cost function, with references to (Hillström et al. 1985), which gives the cost of a CTES in SEK/m^3 as follows:

$$C_{CTES} = C_{CTES(V_0)} * \left(\frac{V}{V_0}\right)^{eb} \tag{2.9}$$

Where V_0 is 100 000 m^3, $C_{CTES(V_0)}$ is 400 SEK/m^3 and eb is set to -0,3. V is the active water volume of the storage.

In addition to the investment cost of excavating the cavern, the initial losses can be seen as an investment cost. The surrounding rock has to be heated up before the losses decrease and the CTES is efficient enough. In the Lyckebo case, as an example, 10 000 MWh of heat was credited to this during the first five years of the storages operation (Åström 2011).

2.6 Exhaust air heat pumps

According to the second law of thermodynamics, heat is transferred from a high temperature, heat source, to a low temperature, heat sink. By adding external energy usually in the form of electricity this process can be reversed and low grade heat can be lifted to higher temperatures and thus become useful. This is the principle operation of a heat pump in heating mode. In more detail this is accomplished by using a refrigerant in a closed loop and a compressor, see figure 2.14 for a simple heat pump layout (Gretzer et al. 2006).

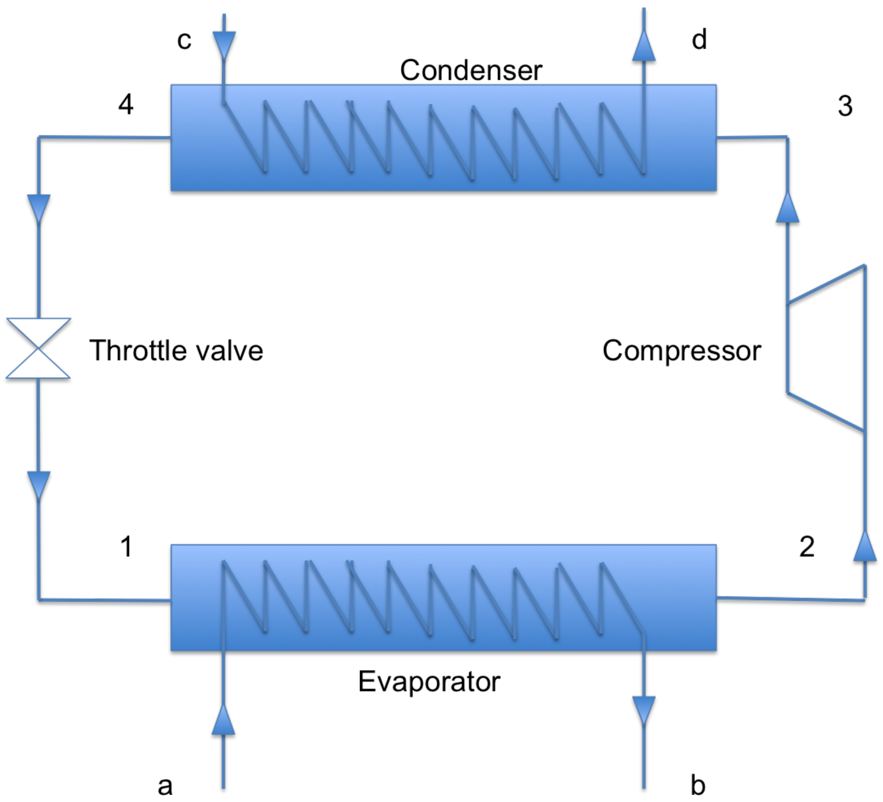


Figure 2.14: Principle schematic of a heat pump.

The operating characteristics of the heat pump are described below (Gretzer et al. 2006):

- 1-2: The refrigerant is evaporated by extracting heat from stream a-b, which could be outside air, exhaust air or some geothermal source. The amount of heat transferred to the evaporator, Q_E, can be calculated according to equation 2.10.
$$\dot{Q}_E = \dot{m}_{1-2} * Cp_{1-2} * \Delta T_{1-2} = \dot{m}_{a-b} * Cp_{a-b} * \Delta T_{a-b} \tag{2.10}$$
- 2-3: The pressure of the refrigerant is increased and as a result the temperature increases. The temperature increase is often referred to as the "temperature lift" and the amount of work required is here denoted as W.
- 3-4: The refrigerant condensates and releases heat to stream c-d, usually this is the internal water system of a building if space heating or hot water is to be supplied. Equation 2.11 describes the heat transfer in the condenser.
$$\dot{Q}_C = \dot{m}_{3-4} * Cp_{3-4} * \Delta T_{3-4} = \dot{m}_{c-d} * Cp_{c-d} * \Delta T_{c-d} \tag{2.11}$$
- 4-1: The pressure of the refrigerant is decreased by a expansion valve, allowing for evaporation at a sufficient low enough temperature in the evaporator.

An exhaust air heat pump, EAHP, utilizes heat in the exhaust air from a building to evaporate the working fluid of the heat pump. The heat recovered in the evaporator would have been lost if not for the heat pump and it should be viewed as a device for heat recovery that complements the main source of heating in a building. The system layout can differ between direct evaporation of the refrigerant and indirect evaporation. Direct evaporation requires that the evaporator is placed in the exhaust air ducts so that the exhaust air heat can be recovered without any intermediate steps. Direct evaporation is common in smaller houses and the heat pumps often come with an integrated exhaust air fan. Indirect heating is used in larger buildings where HVAC system can be located far from the heating central of the building. An auxiliary loop of heat transfer fluid is then used to transfer the heat from the exhaust air to the evaporator. The heat pump then lifts the temperature of the refrigerant and releases heat to the building through condensation in the condenser (Svensk Fjärrvärme 2003).

The advantage of a heat pump is the fact that it supplies more heat than is inserted as electricity in the compressor. The ratio or performance indicator between the useful heat and electricity input is the coefficient of performance, COP. (Gretzer et al. 2006) The equation for COP is calculated according to the following:

$$COP = \frac{\dot{Q}_C}{W} \tag{2.12}$$

A high COP indicates that the heat pump can supply a lot of heat relative to power input. The COP can also be described with the temperatures for the evaporator and condenser, see equation 2.13 below:

$$COP = \eta * \frac{T_C}{(T_C - T_E)} \tag{2.13}$$

T_C is the condenser temperature and T_E is the evaporator temperature, the quota including these two temperatures in equation 2.13 describes an ideal coefficient of performance for a heat pump process with no losses. η is an efficiency value that compares the actual system performance with the ideal process. The efficiency rating of a system can varies greatly but values between 0.5-0.7 have been found in literature (Svensk Fjärrvärme 2003).

The effects that exhaust air heat pumps have on the district heating system will be studied in this thesis and background regarding why building owners would choose to install a second heat source is further reviewed below.

2.6.1 Future expansion of exhaust air heat pumps in Gothenburg

When deciding if a heat pump should be implemented as an additional heat source to district heating the following should be considered (Boss, A. 2012);

- Will the energy usage increase or decrease as a result of acquiring a EAHP.
- What will the running and investment costs be.
- Legislative obligations considering energy consumption.

When deploying a heat pump, a part of the heat delivery from the district heating will be replaced by the heat pump. The electricity, W, consumed by the heat pump can be expressed as a function of the delivered heat, Q_C, and COP value by rearranging equation 2.12. With a COP above 1 the electricity input, W, is lower than the heat delivered, Q_C, and by this the total energy usage by a consumer will decrease when utilizing a heat pump. However the cost for electricity is generally higher than for heat. With no or little control of the heat pumps operation with respect to electricity and heat prices, one can end up supplying heat from the EAHPs when they are not the most cost optimal option. Furthermore the environmental impact will not definitely decrease because of lower energy usage. Electricity can be associated with higher emissions and this can offset the reduced CO_2-emissions that was achieved by the reduction of energy usage (Boss, A. 2012).

The cost of an additional heat source can be large and the profitability tends to increase with larger systems as more energy over the year is supplied and the investment becomes more distributed. A problem that arises for building owners is that some utility companies that supplies district heat have introduced extra fees that is based on the maximum power required in buildings and the return temperatures to their grids. The required power does not decrease at the same rate as the energy decreases for the district heating companies and the profitability of a heat pump is in this case not solely dependent on the decrease in energy delivered. An additional cost is also the staff and knowledge needed for operating a combined system as opposed to a single system where district heat supplies all the demand (Boss, A. 2012).

The amount of allowed consumed energy for buildings is regulated by Boverket. The energy consumption differs between buildings that are heated by electricity and district heating. A building heated by electricity has a lower allowed energy consumption compared to buildings heated by other sources. A house is qualified as electricity heated if the installed power exceeds 10 W/m^2. With a low amount of installed heat pump capacity the building can comply with the higher limit for energy usage while still supplying a significant part of the total yearly load with electricity (Boverket 2014). In interviews regarding future residential buildings some construction companies in Gothenburg states that heat pumps in new buildings might be needed to reach future legislation and company driven policies (Johnsson et al. 2016).

Intermittent power production due to the deployment of low carbon emitting power sources such as wind and solar is expected to increase in the future. A result from this will be recurring situations were the electricity demand is far less than the supply creating a surplus of electricity in the grids. A way of handling these surges of surplus electricity is to generate heat from electricity, so called power to heat conversion. District heating systems can by this be used to add flexibility to the electricity system. This has been done historically in Sweden by utilizing electric boilers for heating and hot water after the introduction of several nuclear power plants that resulted in an over capacity within the Swedish electricity system (Averfalk et al. 2014).

The electricity price during a surplus is usually very low since the price of electricity depends on supply and demand. District heating companies that operate CHP plants and/or large heat pumps will both benefit and get penalized by these low electricity prices. Heat pumps require electricity to be able to lift low temperature heat to a higher temperature where the heat becomes useful. Heat pumps will therefore benefit from low electricity prices. The same reasoning can be applied to smaller heat pumps that are deployed in multi-family buildings. Given a sufficient low electricity price these heat pumps can use cheap electricity to satisfy the heating demand at a lower cost than the district heating company (Averfalk et al. 2014).

The implementation of exhaust heat pumps in the current building stock where a district heating connection already exists has been investigated in (D. Olsson 2016b). As a means of reaching the Swedish climate goals of 2020 and 2050 extensive measures regarding energy efficiency in current buildings are required. For Gothenburg, a contribution to this decrease in energy consumption could be seen in the planned refurbishment of old existing buildings. A criteria needed for a building to be considered to invest in an EAHP is that it already has mechanical exhaust air ventilation. The reason for this criteria is that the EAHP would be able use the same ducts and thus greatly reduce the investment and installation costs since no new ventilation channels would have to be constructed. The amount of building area that can be considered to be undergoing refurbishment in the near future is approximated to 5 million m^2 (D. Olsson 2016b).

2.6.1.1 Heat source shifting

Today heat pumps are controlled to always have priority over the district heating connection. District heating then acts as a peak and intermediate heat source. This is not the most cost optimal solution for the heating system since there are hours where the electricity price is much higher than the price of heating and the district heating connection should have priority. (Kensby et al. 2016) assessed the combinations of heating sources in the residential sector of Gothenburg that are connected to the district heating system. They found that in Gothenburg the most common combination of heat sources are exhaust air heat pumps together with a district heating supply. The portion of residential multi-family buildings with a exhaust air heat pump was found to be 2.7%.

The effects of running the combination of EAHP and district heating in the most cost optimal setup were investigated by (Kensby et al. 2016). An hourly heat tariff was implemented in conjunction with hourly electricity spot prices for the year 2013-2014. This was applied through a simulation of a typical building in the Gothenburg area of Västra Gårdsten. According to this study the cost for the consumer could be decreased by 3.2% when utilizing the cheapest means of space heating. A criteria that need to be fulfilled in order to be able to shift between HP and DH is that the price of heat and electricity need to be available on an hourly basis for the consumer. The hourly price of electricity is already available on Nordpool through the day ahead spot-market for any customer but no counterpart is readily available for the district heating area. (Kensby et al. 2016)

3 Methods

The generation of district heat in 2032 is modelled in the linear program solver software GAMS. The model solves an optimisation problem, where the objective is to minimize the total yearly cost of the system. Therefore, from here on the simulation will be referred to as an optimisation. The model has got an hourly resolution, which in practice means that information is available regarding the demand for heat, cost of electricity, outdoor temperature et cetera for every hour of the year. Given this information, the model decides the heat generation dispatch in each hour that gives the lowest total system cost over the entire year. The total system cost is here defined as the sum of all running costs of all heat generation plants after electricity generated in CHPs has been sold. In these costs, neither VAT nor grid fees are included, since the aim of the optimisation is to minimise the *system* costs. In principal, the objective function of the optimisation model can be written as:

$$TC_{system} = \sum_{i} \sum_{t} VC_{i,t} - el_{CHP,t} + SUC_{SU,t} \tag{3.1}$$

Where $VC_{i,t}$ are the variable costs of each heat generation plant, including fuel costs, taxes et cetera in every time step. $el_{CHP,t}$ describes the amount of electricity that is produced in CHP plants and can be sold to the electricity market, thus decreasing the total system cost. $SUC_{SU,t}$ denotes start-up costs that arise from the fact that some heat generation plants have a start-up cost associated with its operation. In every hour of the year, the generated heat in the system has to equal the demand in that hour. This is described by:

$$\sum_{i} x_{i,t} = D_{heat,t} \quad \forall t \tag{3.2}$$

These two expressions describe the two most important constraints that are set in the optimisation model. The optimisation model that was used as a basis for the work in this thesis was originally developed as part of a previous masters thesis at the division for Energy and Environment at Chalmers University (Akkaya et al. 2013). The model used in this thesis has also included recent updates to the original model from (Akkaya et al. 2013), which are part of ongoing research by Dmytro Romanchenko.

The optimisation model was used to evaluate scenarios that are deemed to be plausible in the Gothenburg district heating system in 2032. These scenarios have been selected after discussions with representatives of Göteborg Energi with insight in future development in the heat utility (Hjalmarsson 2016), (Sommansson 2016) and (Kensby 2016). These scenarios include:

- Thermal energy storage in a hot water accumulator tank.
- Utilizing the building stock as thermal energy storage.
- Seasonal thermal energy storage in a cavern.
- Increased amount of exhaust air heat pumps in the building stock.
- Increased flexibility of exhaust air heat pumps in the building stock.

The implementation of these scenarios in the optimisation model is described in this chapter. In addition to this, some input data for the simulation was required to be adapted for a future scenario. This adaption is described in the following section.

3.1 Adaption of the heat load profile to 2032

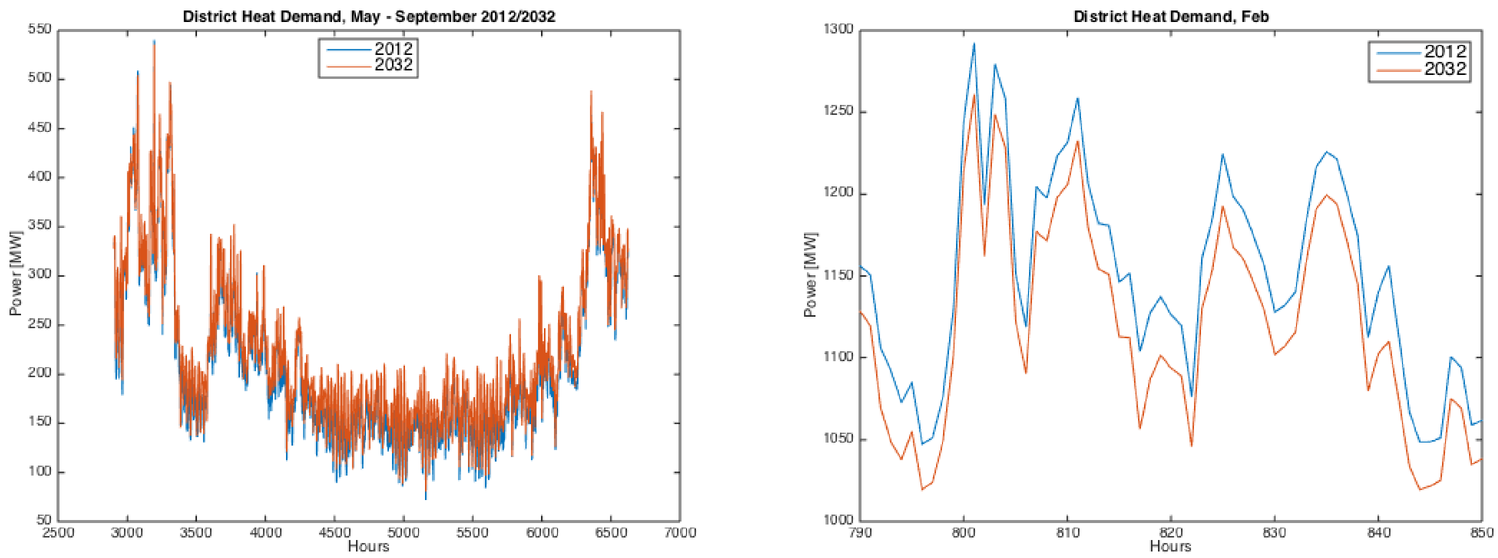
As stated in 2.3 and 2.3.1 the future total heat demand of 2035 can be expected to be constant or increase by about 2 % compared to 2012, while the hourly load profile could experience a development towards a more flat characteristic with less space heating being needed during cold hours and more hot water being used overall. An approach was made in this thesis to adapt an hourly heat load profile from 2012 into a heat load profile that would reflect the anticipations for 2032.

The heat load data from 2012 was adapted to a heat load profile representing the year 2032 with respect to two major parameters. The first one is decreased space heating due to energy efficiency measures carried out in existing buildings between 2012 and 2032. The existing buildings include multi-family residential buildings, industrial properties, commercial buildings and smaller houses. The second parameter that was taken in to account was the increase of hot water load because of new residential buildings constructed by 2032 (Johnsson et al. 2016).

The space heating load of any building is depending the outdoor temperature. As the outdoor temperature decreases, the space heating load increases and vice versa (Utzinger et al. 2016). The temperature dependence was approximated by using a least square fitting of the hourly outside temperature and the corresponding heat load for 2012. This yielded an approximated linear relationship between the outside temperature and the heating load of Gothenburg. A balance temperature of 15°C was used in conjunction with a desired room temperature of 21°C. With an ambient temperature equal to the balance temperature no additional space heating is needed, instead the internal heat gains of a building is sufficient to reach the desired indoor temperature (Utzinger et al. 2016). The reduction in total space heating load due to efficiency measures was set to 0.9091 of the 2012 levels according to 2.3. By implementing efficiency measures in buildings two significant benefits arise. The balance temperature decreases which effectively reduces the amount of hours that need space heating and the required power during hours that need additional space heating also decreases.

The increase in hot-water demand was to be added because of new buildings in the region and was based on heat load data for a residential area called Västra Gårdsten in Gothenburg instead of the total heat demand data. The reason for this was that the total heat demand includes many different sources of heat loads, making it difficult to capture the hourly variations of hot water usage in residential buildings. A least square fitting of the daily heat delivery variation with respect to time of day was performed in order to capture the hourly trends of hot water usage. The absolute values of this curve was deemed to be too high since the data set was not yet reduced by the load associated with space heating. An assumption was made that the load during the summer months mainly consists of hot water heating and a final curve fit was performed on this period. The hot water load profile was scaled with an estimated amount of 57 000 new residential buildings by 2032.

The total yearly heat load is increased by 0.44% after performing the adaption described above which is within the estimates found in literature. Two segments of load profiles for actual load in 2012 and the adapted load profile of 2032 can be seen below in figure 3.1. Figure 3.1a shows the heat load for June and 3.1b presents a cold period in February.



(a) Increased hot water demand during summer.

(b) Less space heating needed for cold peaks.

Figure 3.1: Resulting heat load curve in 2032 after adaption from 2012.

It can be seen above in figure 3.1(a) that extra hot water demand of new buildings increases the load throughout the summer and the space heating load has overall decreased, especially during the cold hours with high heat load, figure 3.1(b).

In section 2.3.1 two indicators for heat load variations were presented, the relative daily variation and the annual relative seasonal variation. These were calculated for the 2012 heat load profile as well as for the adapted 2032 load profile. The Annual relative seasonal variation decreased from 25.02% to 23.90% meaning that the seasonal variations are lower in the adapted curve used for 2032. The relative daily variation is plotted in figure 3.2 below.

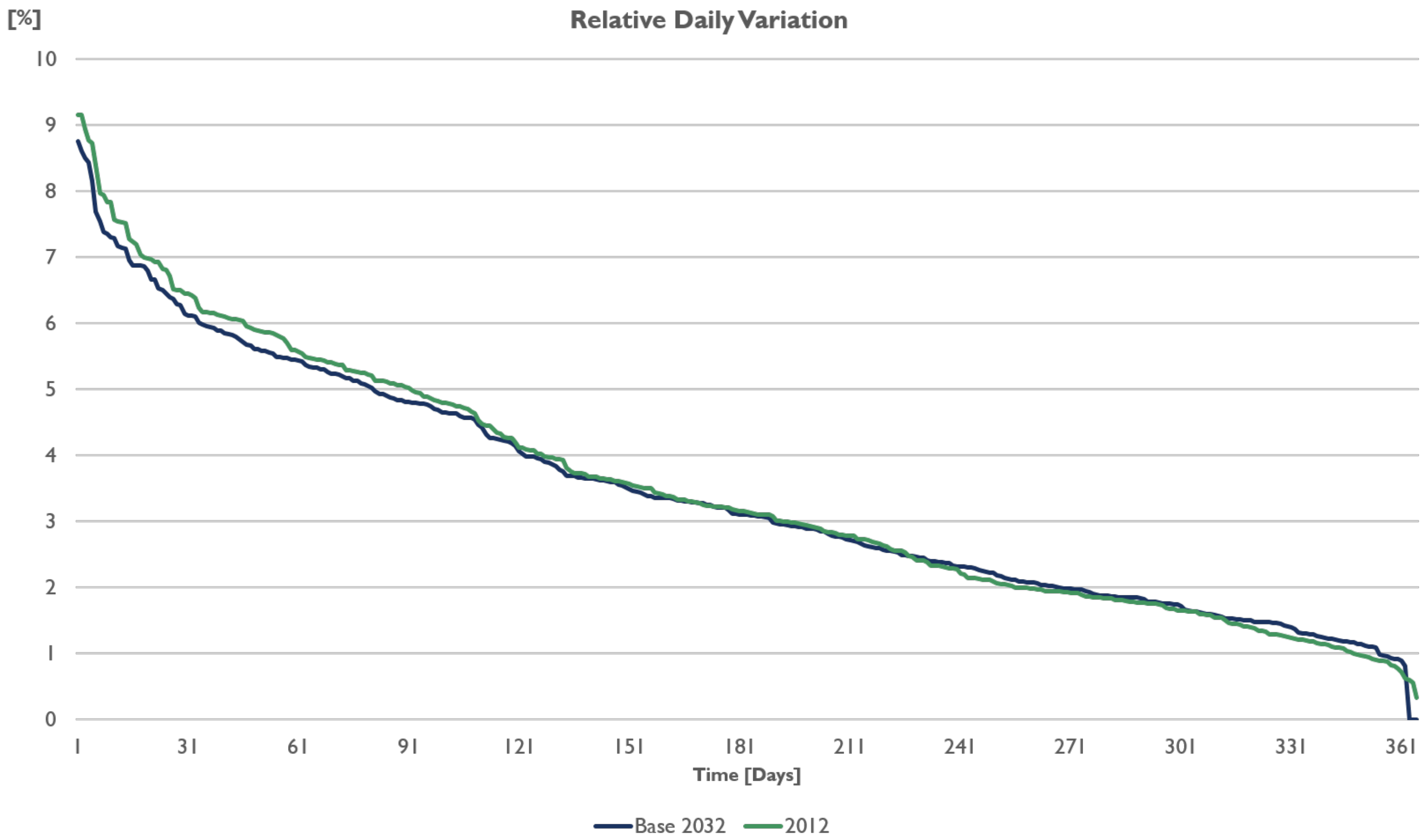


Figure 3.2: Relative daily heat load variation for load profile of 2012 and adapted profile for 2032.

The relative daily heat load variation decreased after adapting the load profile from 2012 to represent the load profile in 2032. The decrease in heat load variation is expected since the adaption of the load profile was made with the ambition to flatten out the load profile according to theory described in section 2.3.1.

3.2 Base model, 2032

Several scenarios are investigated in this thesis. In order to properly evaluate them, a baseline scenario is set up as reference. All other studied measures are compared to this base case and factors such as heat generation, total system running costs and heat load variation are evaluated. The base case represents a scenario that is deemed as highly plausible to happen in the Gothenburg district heating system by 2032. It includes the construction of a new CHP plant fuelled by wood chips and the substitution of natural gas to bio gas. It is assumed that no heat generation plants are taken out of operation. No other fuels than natural gas are substituted and their costs are kept at their 2012 levels. There will be some fossil fuelled HOBs still in the system by doing this. These are kept for the event of extremely low outdoor temperatures and will likely not be put into operation during a year with normal temperature levels. All other studied scenarios are examples on measures that can be taken in addition to the base case in order to optimise the generation of heat in terms of running costs and other factors. The base case is described in the following sections.

3.2.1 Heat Generation and Distribution Development in the District Heating System

A likely development in the Gothenburg district heating system is the construction of a new biomass-fuelled CHP plant, in order to meet the zero CO_2-target by 2030. This assumption is made after consulting personnel at Göteborg Energi with insight in the future plans of the utility, however it should not be seen as a definitive decision. In the event of such a plant being constructed, it would be in the range of 100 MW_{th} (Hjalmarsson 2016).

In 2014, a biomass-fuelled CHP plant by roughly the same size was commissioned in Örtofta in the south of Sweden. The plant, "Örtoftaverket", has a thermal capacity of 88 MW and an electrical capacity of 39 MW, giving a power-to-heat ratio of 0.44. The total efficiency of the plant with flue gas condensation taken into account is 100% (Kraftringen 2015). The new CHP plant in Gothenburg would likely have similar technical specifications if it were to be built. Start-up cost, minimum load and ramp rates for heat generation are likely to be similar to the existing Sävenäs CHP (Hjalmarsson 2016). Therefore, a CHP plant with the specifications presented in Table 3.1 is added to the heat generation mix in 2030. One could argue that the performance of a new plant would be higher than this, but using these specifications gives a conservative estimate.

Table 3.1: Technical specification of new biomass CHP

Capacity heat [MW]	100
Capacity electricity [MW]	44
α	0.44
Primary fuel	Wood chips
Total efficiency [-]	1.00
Minimum heat load [MW]	22
Ramp rate heat [MW/h]	40
Ramp rate el. [MW/h]	18

3.2.1.1 Substitution of natural gas to bio gas

A likely future scenario as stated in personal communication with representatives from Göteborg Energi, is that the use of natural gas in the generation of district heat will be decreased heavily by the year 2032 (Hjalmarsson 2016). This decrease will be achieved by favouring the use of gas derived from biomass in the large plant Ryaverket, which is currently primarily fuelled by natural gas. This is represented in the model by an increased fuel cost, which will place the Rya plant lower in the merit order and the plant will consequently be run more to cover peak loads rather than base.

A factor that has a great influence on the results is the predicted future price of bio gas. This prediction is difficult to make, since district heating is not the only sector where bio gas could be used. It is likely that a large amount of the future produced bio gas will be used by vehicles, which would affect at which price that district heating providers can purchase bio gas (Zinn 2016).

A recent, large study showed that there is indeed a large potential to produce bio gas in Sweden at a competitive price (Börjesson et al. 2013). The same study approximates a likely future cost to produce bio gas as somewhere in the range 5 to 8 SEK per liter gasoline-equivalent. This converts to roughly 560 to 900 SEK per MWh, under the assumption that one liter of gasoline is equivalent to 8.94 kWh (Svenska Petroleum- och Biodrivmedel Institutet 2016). it should be noted that the production cost of bio gas is highly dependent on the type of gasification process that is used, the biomass used and the location at which the gasification takes place (Börjesson et al. 2013). In this report, the average of the two costs mentioned above were set as the price for bio gas, i.e. 730 SEK/MWh.

3.2.1.2 Other fuel costs

All fuel costs used to model the future scenarios are set to values equivalent to their levels in 2012. The fuel costs used are presented in Table 3.2 below:

Table 3.2: Fuel costs used in optimisation models

Fuel	Cost [SEK/MWh]
Wood chips	209
Wood pellets	292
Bio Oil	600
Bio gas	730
Fuel oil	542

The cost of electricity is set on an hourly basis with values taken from the scenarios GP, RP and CM as described in Section 2.4. The fuel prices are collected from (Energimyndigheten 2014) and (Energimyndigheten 2012).

3.2.1.3 Renewable electricity certificates

The electricity certificates system, ECS, in Sweden was started in 2003 and aimed to facilitate the deployment and development of the renewable power sector in Sweden. Since 2012 Sweden and Norway have a shared market for certificates allowing certificates to be issued in Sweden and consumed in Norway and vice versa. The goal is to increase the amount of electricity produced from renewable sources by 15.2 TWh in Sweden and 13.2 TWh in Norway until 2020 (Energimyndigheten 2015b).

Renewable producers acquire one certificate for every MWh of produced electricity and this certificate can be sold to the distribution companies which are obligated to purchase a certain amount of certificates related to their delivered energy (Energimyndigheten 2015a).

The quota of certificates that distributors need to acquire in 2032 is already decided to 7.6% (Energimyndigheten 2016a). The certificates are priced according to the supply and demand of electricity and thus have not a set price. The average price of a certificate calculated from April 2004 up until August 2016 is 212.8 SEK/certificate, the mean high value for the period almost reached 350 SEk/certificate and the mean low 140 SEK/MWh. The average during the past two years is about 169 SEK/certificate (Energimyndigheten 2016b).

With a smaller quota needed to be compensated for by utility companies in 2032 compared to 2016 and the same or larger production of renewable electricity suggests that electricity certificates in 2032 will be cheaper. In the optimisation model, the price for electricity certificates is set to 120 SEK/MWh to reflect this reasoning. It should be noted that unforeseen developments in the power and political sector together with the inherent uncertainties associated with self regulating markets could result in a vastly different price of certificates.

3.2.1.4 Electricity Price

The components of the electricity price have been presented in 2.4.3 and are shown below in table 3.3.

Table 3.3: Electricity price components

	[SEK/MWh]
Spot price	marg.cost of GP, RP, CM
Grid fees	-
REC	9,12
Energy tax	290
VAT	-

The spot prices used in this model are the marginal costs from the electricity sector scenarios described in 2.4. The price of REC is set according to 3.2.1.3. The grid fees and VAT for electricity is excluded in the model. The reason for this is that the aim of the model is to minimize the system cost of generating heat in the Gothenburg region. When generating electricity in a CHP or consuming electricity in a HP only the spot price, energy tax and REC are included. The optimisation is performed from the perspective of generating heat at a minimal cost, not to maximise profits from electricity sales, which is why grid fees and VAT are excluded.

3.3 Scenarios

With the base case defined, the scenarios to be studied were implemented as additions to the base case. As stated previously, these scenarios include TES in an accumulator, buildings and in a cavern. Additionally, a scenario includes an increased use of exhaust air heat pumps in buildings. Two combinations of these scenarios are also studied, the following sections describe their implementation in the optimisation model and assumptions that were made in order to do this.

3.3.1 Thermal energy storage in an accumulator tank

Göteborg Energi are currently planning to construct a hot water accumulator tank in order to reduce peak demands of district heat. The proposed accumulator is still in an early planning phase, but will likely have a storage capacity around 1000 MWh and a power capacity of 130 MW (Hjalmarsson 2016). For comparison, in 2009, a 1600 MWh accumulator tank was put in to operation in the city of Borås, close to Gothenburg (Svensk Fjärrvärme 2010). The tank would be of the atmospheric pressure type with a temperature difference of approximately 50°C. This would result in an approximate active water volume according to Equation 2.5 as:

$$V_{acc} = \frac{E_{acc}}{\rho_{water} c_{p,water} \Delta T_{water}} = \frac{1000 * 10^6 * 3600}{995 * 4200 * 50} = 17,528\ m^3$$

Where physical properties of water are retrieved from (Mörtstedt et al. 1999). From this preliminary volume, Equations 2.6 and 2.7 can be used to give a rough estimation of the costs associated with the tank. These sum up to 46 MSEK, but this figure is very uncertain, since connection costs are not accounted for. Again, for reference, the accumulator tank in Borås had a reported budget of 100 MSEK (Svensk Fjärrvärme 2010).

3.3.1.1 Model Implementation

In the GAMS model, a storage technology is in its most simple form modeled as a storage capacity (in MWh) and a power capacity (in MWh/h). One constraint keeps track of the stored amount of energy in each time step according to:

$$E_{storage}(t) = E_{storage}(t-1) * (1 - \phi_{storage}) - \dot{Q}_{storage}(t) \quad \forall t \tag{3.3}$$

Where $E_{storage}$ is the amount of energy stored in each time step, $\phi_{storage}$ is a loss factor and $\dot{Q}_{storage}$ is the energy that is either charged or discharged in each time step, in this case MWh/h. If the storage is charged, $\dot{Q}_{storage}$ is negative by the definition in equation 3.3. Vice versa, when the stored energy is discharged, $\dot{Q}_{storage}$ is positive. The losses from an accumulator tank depend on the outside temperature, the stratification of the tank and several other factors, as described in Section 2.5.1. The simulations performed in this thesis have a large scale perspective, and the losses are relatively small in comparison to the stored energy and the power associated with the tank. therefore, a highly simplified model of the losses was used. The losses are modelled as a percentage, $\phi_{storage}$, of the stored capacity in the tank in every time step. The loss factor $\phi_{storage}$ is set to 0.1%, which is the sum of the static and storage loss factors as described by (Steen et al. 2015) in Section 2.5.1.

When the storage is charged with heat, the total demand for heat in the system is increased and when the storage is discharged the demand for heat decreases. Therefore, Equation 3.2 is modified when storage is added to the system accordingly:

$$\sum_i x_{i,t} = D_{heat,t} - \dot{Q}_{storage,t} \quad \forall t \tag{3.4}$$

It is assumed that the storage is charged at half of its capacity in the first hour of the year. This is simply an effort to give the simulation a starting value and could be set to anything between 0 and 100% state of charge. Since the storage charges and discharges relatively fast, the starting value has little impact on the yearly performance of the storage.

3.3.1.2 Simulation time horizon

When storage is added to the system, the mixed integer problem becomes increasingly complicated to solve. Simulation times become very long because of this and therefore, the year must be divided into a number of shorter periods. This is not necessarily a disadvantage, as it might resemble actual operation of the system, where the time horizon never is an entire year. In this case, the simulation is divided into six equally long periods, containing 1752 hours each, approximately two months.

The simulations are run in sequence, where the values of the variables in the last hour of the previous period are used as input for the first hour of the consecutive period.

3.3.2 Buildings as Thermal Energy Storage

Utilizing the building stock in Gothenburg in a future scenario is deemed to be highly plausible. This is supported by the fact that during the fall of 2016, a large-scale pilot test of the principle is being conducted in Västra Gårdsten in Gothenburg. About 2000 apartments are being utilized as a thermal energy storage (Kensby 2016). For the purposes of this report, it is assumed that in 2032, buildings connected to the 500 largest DH substations in Gothenburg will be utilized as TES. This corresponds to 20% of the total generated heat in Gothenburg today.

Under this assumption, the maximum total charge/discharge rate from all buildings adds up to 63 MW, using the power signature of the buildings in Västra Gårdsten (Kensby et al. 2014). The hourly maximum charge rate, however, depends on the outdoor temperature, as described in Section 2.5.2. This is visualized in Figure 3.3, the maximum charge capacity is available at outdoor temperatures below 8°C and decreases linearly from 63 MW to 0 MW between 8 and 15°C. Historic hourly temperature data for 2012 was available and the hourly charge capacity could thus be calculated for use in the model.

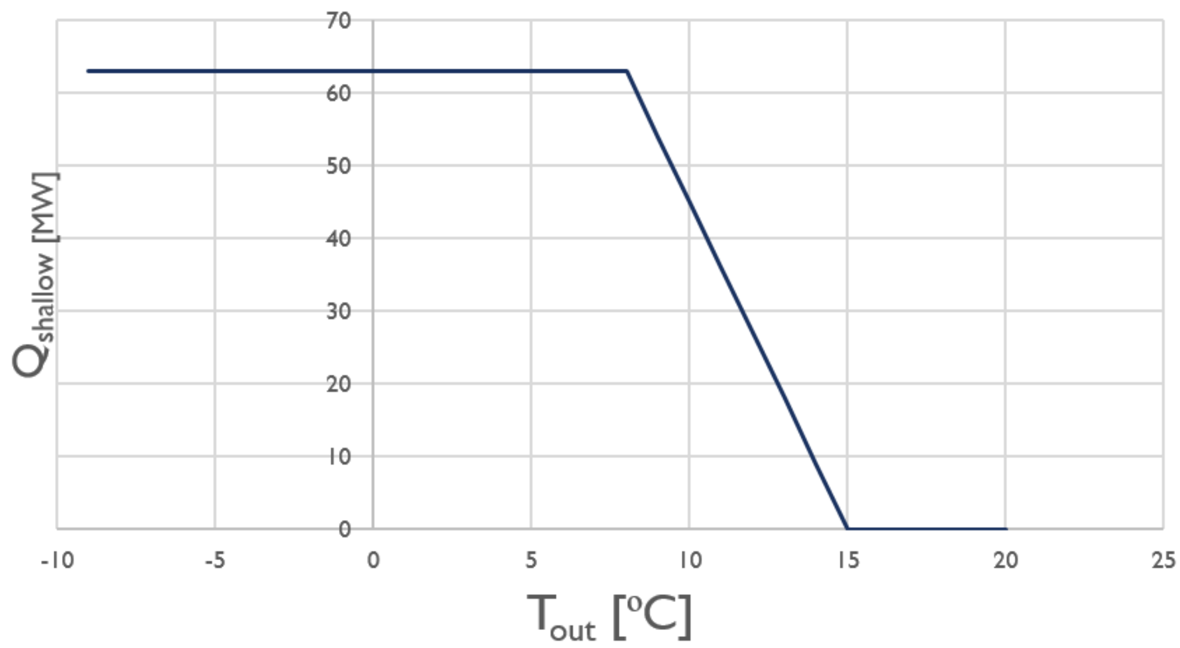


Figure 3.3: Maximum charge capacity of buildings utilized as TES at varying outdoor temperature

Based on the results presented in (Carlsson 2016) and (Kensby et al. 2015), the storage capacity of the buildings were divided into a shallow and a deep part. The shallow storage in all buildings is estimated to have an accumulated storage capacity of 278 MWh, while the deep storage is estimated to have a capacity of 1758 MWh. These figures come from a parameter fit that gives results that correlate well with actual measurements from the pilot study in (Kensby et al. 2015). As can be seen in Figure 3.4, the rate at which heat flows between the deep and shallow storage,

$\dot{Q}_{deep}$, is modelled as a linear relation between the amount of energy stored in each storage.

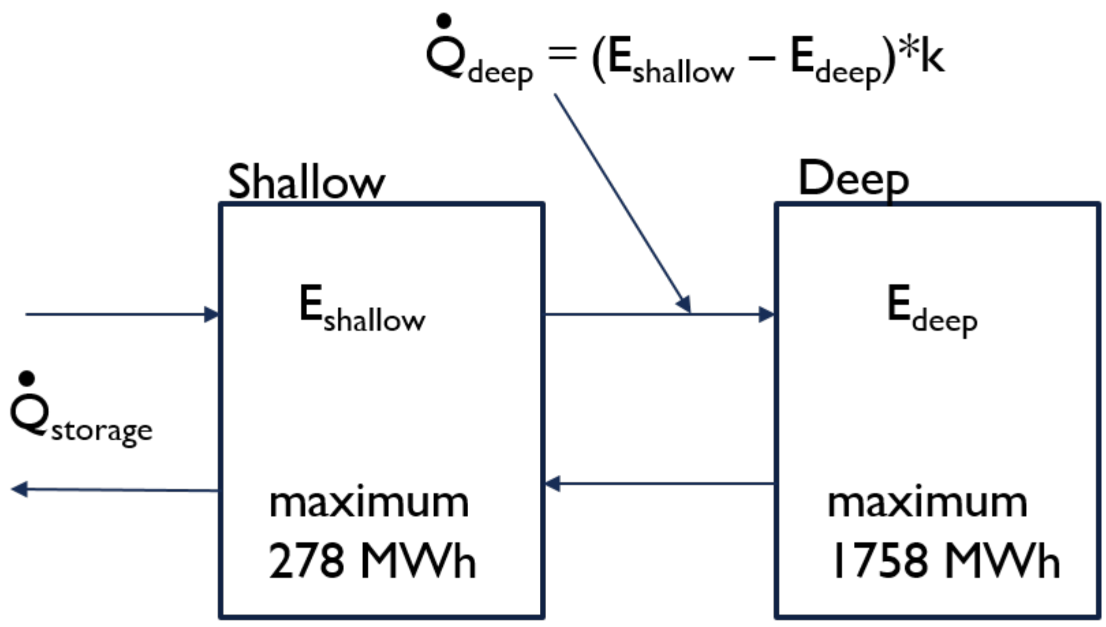


Figure 3.4: Principal sketch of building thermal storage used in simulations

The stored energy is expressed as a quota between the stored energy in each hour over the maximum possible amount stored in each storage. The constant k is adjusted to fit data in (Carlsson 2016) and (Kensby et al. 2015) and is set to 180 MW. In summary, $\dot{Q}_{deep}$ is expressed as follows:

$$\dot{Q}_{deep} = \left(\frac{E_{shallow}(t)}{E_{shallow,max}} - \frac{E_{deep}(t)}{E_{deep,max}}\right) * k \quad [MW] \tag{3.5}$$

The optimisation model can thus select a value for $\dot{Q}_{storage}$ within its limits of every hour, while there is no direct control of $\dot{Q}_{deep}$. However, the relationship between the two is known, and the model can plan the charge/discharge strategy thereafter. The installation costs of using 500 DH substations are estimated to be around 12 MSEK, since the installation cost for one DH substation is in the magnitude of 24,000 SEK.

When utilising buildings as thermal energy storage, the overheating and underheating of buildings is superpositioned in the existing heating system. If the energy consumption of the building includes losses to the outside of the building, the use of buildings as thermal energy storage can be said to be without heat losses. This is best explained through an example; say that the heating system of a building is designed to keep an indoor temperature of 21°C, then the energy consumption of the building includes the energy that is needed in order to keep the temperature at 21°C, including heat losses which occur because the outdoor temperature is lower than 21°C. Now, if one increases the indoor temperature in order to charge the building with heat, the heat losses to the outside would of course also increase. When the indoor temperature is instead decreased, the heat losses to the outside would decrease since the temperature difference between the interior and exterior of the building decreases. If the building is overheated as much at it is underheated during a year, the increases and decreases in heat losses cancel each other out. Therefore, the storage is modelled without any heat losses.

3.3.2.1 Model Implementation

In principle, the modelling of utilizing buildings as TES is similar to the modelling of TES in an accumulator tank, described in Section 3.3.1.1. The overall heat demand balance is still described by Equation 3.4, where $\dot{Q}_{storage,t}$ describes the charge rate to and from the shallow storage and the DH system. The difference from an accumulator tank is that the maximum charge rate is variable and depends on the outdoor temperature of each hour, as described in Figure 3.3. Therefore, two additional constraints are added to the model, which limits the charge/discharge rate in each hour accordingly:

$$\dot{Q}_{storage,t} \leq \dot{Q}_{storage,max,t} \qquad \forall t \tag{3.6}$$

and

$$\dot{Q}_{storage,t} \geq -\dot{Q}_{storage,max,t} \qquad \forall t \tag{3.7}$$

where $\dot{Q}_{storage,max,t}$ is the maximum charge/discharge rate in every hour. Equation 3.6 denotes the discharge rate and Equation 3.7 the charge rate by definition.

In order to describe the stored energy in the two storages, the general storage expression in Equation 3.3 is modified according to the reasoning above. The loss factor $\phi_{storage}$ is set to zero and is omitted here. The amount of stored energy in the shallow storage is the sum of the stored energy in the previous time step plus the charged energy from the DH system, $\dot{Q}_{storage}$, and the charged energy from the deep storage, $\dot{Q}_{deep}$, which is expressed in Equation 3.5.

$$E_{shallow}(t) = E_{shallow}(t-1) - \dot{Q}_{storage}(t) - \dot{Q}_{deep}(t) \qquad \forall t \tag{3.8}$$

Similarly, the energy stored in the deep storage is expressed as:

$$E_{deep}(t) = E_{deep}(t-1) + \dot{Q}_{deep}(t) \qquad \forall t \tag{3.9}$$

Note that $\dot{Q}_{deep}$ is added as positive in this case, from definition. If $\dot{Q}_{deep}$ is positive, the deep storage is charged, the shallow storage is discharged and vice versa.

3.3.2.2 Simulation time horizon

Adding buildings as a storage to the model greatly increases the complexity of the model and therefore also simulation time. As in the case with an accumulator tank, the simulation was divided into periods in order to remedy this. The model with building storage implemented was divided into even shorter periods, comprising of 876 hours each.

3.3.3 Seasonal thermal energy storage

If a seasonal storage were to be constructed in Gothenburg, a likely technology to be used is CTES. In order to make use of the cooled off heat and unused capacity of waste heat during summer months, a storage capacity of 200 GWh is proposed. The power capacity of this would-be storage is 300 MW (Hjalmarsson 2016).

A CTES of this magnitude would require a storage volume of approximately 4,000,000 m^3 at a temperature difference of 50°C (Zinko et al. 2008). A likely depth of the storage volume would be 200 m. If the storage for simplicity's sake is designed with a quadratic cross-section, the dimensions of the storage would be $133x133x200$ m. An estimated minimum excavation cost for this storage, from Equation 2.9, would be roughly 600 MSEK.

The losses from a CTES are hard to estimate before the storage has been excavated, but literature shows that the relative losses are very small, compared to the stored energy. For the purposes of this thesis, it is not vital that the losses are modelled perfectly, and a loss factor similar to the one used for the accumulator tank was used. The percentage of heat energy lost per hour in the CTES where set to 0.0019% as this gives yearly losses of around 10%.

Implementing seasonal storage to the GAMS model resembles that of the accumulator tank storage. Equations 3.3 and 3.4 are used without any other alterations than that the storage capacity and power capacity are changed accordingly. It is assumed that the storage is operated in such a way so that all available thermal energy is discharged by the time the winter heating period is over. Figure 2.2 shows the demand for heat in 2012. It can be seen that there are two major peak demand periods during a year, in December and January/February. Around hour 3300, which is on the 17th of May, the demand for heat is more or less on a minimum yearly level. Therefore, a constraint is set on the amount of energy in that hour according to:

$$E_{storage}(t = 3300) = 0 \tag{3.10}$$

This assumption gives a starting value for the simulation. It is however problematic that the starting value is not given for the first hour of the year. It is very difficult to estimate at which state of charge that the storage should have on January 1st, as this would depend on the amount of energy stored during the previous year of operation. As a remedy for this, the simulation is run as if hour 3300 were the first hour of the year and that a year stretches across new years eve into the next year. After simulations are run, the results are adapted so that hour 1 is on January 1st again.

3.3.3.1 Simulation time horizon

When simulating a seasonal storage, it is important that the time horizon of the simulation stretches over the entire year. Choices on how the system is run in January affects the results in August. Therefore, the year is not divided into shorter periods as was the case for a accumulator storage. A seasonal storage is easier to optimise than a short term storage, so simulation times are reasonable even with a longer time horizon.

3.3.4 Heat Source Shifting with Exhaust Air Heat Pumps

An interesting and uncertain aspect for the future district heating system is the level of deployment of an extra heat source in new buildings and in buildings that will be refurbished before 2032, and the effects that these could have on the heating system operation and costs. In this thesis, it is assumed that if an extra heat source is installed in buildings, it would be an exhaust air heat pump. The combination of supplying a building with heat from district heating and an exhaust air heat pump is the most common combination in Gothenburg today. In Gothenburg, 2.7 % of all multi-family residential buildings are equipped with this set-up, and therefore this thesis examines the effect of an increase of this combination by 2032 (Kensby et al. 2016).

No reliable source regarding the amount of future deployment of exhaust air heat pumps could be found. Therefore several simulations with different levels of heat pump penetration in the existing and future building stock were performed.

In order to model the exhaust air heat pumps two limiting factors regarding power output needed to be investigated and quantified. The first limiting factor is the amount of space heat that the heat pump can deliver at any given hour. The second is the amount of space heating demand: some hours will have more heating capacity available than is required for the buildings.

The major assumptions regarding the implementation of the EAHPs in the GAMS model were:

- The COP value of the heat pumps are approximated as a function of outdoor temperature by creating a curve fit of two data sets regarding COP values at different outdoor temperatures. Effectively, this means that the all exhaust air heat pumps have identical performance.
- The heat pumps only supply space heating power. Hot water heating is supplied by district heating.

The amount of space heating that the EAHP can deliver through its condenser can be calculated according to equation 3.11

$$Q_{cond} = Q_{evap} + W_{pump} \tag{3.11}$$

Where Q_{evap} is calculated according to 3.12.

$$Q_{evap} = \dot{V}_{exh,air} * \rho_{air} * Cp_{air} * (T_{exh,air} - T_{exh_out}) \tag{3.12}$$

The flow of exhaust air, $\dot{V}_{exh,air}$, is set to be 0.35 $l/s - m^2$ according to Swedish legislation on HVAC systems (Boverket 2010). The value for density,$\rho_{exh,air}$ and specific heat,$Cp_{exh,air}$ were approximated as constant variables at 13 $°C$. The exhaust air temperature, $T_{exh,air}$ from a building is here defined as 21 °C. However, due to poor insulation and leakage in ducts the exhaust temperature decreases with colder temperatures, especially if the ducts go through an uninsulated attic which is much colder than the inside of a building. This phenomena was captured by reducing the exhaust temperature by 5 °C at an outside temperature of -5 $°C$ and creating a linear relationship between the outside and exhaust air temperature (D. Olsson 2016a). Furthermore a common design strategy is to limit the temperature of exhaust air exiting the heat pump to not cool further than 5 $°C$, this design strategy helps to avoid defrosting equipment and this constraint was incorporated in the scenario (Kensby et al. 2016).

W_{pump} can be rewritten as a relationship between Q_{cond} and COP and the maximum capacity of the heat pump is calculated. The final equation is described below: 3.13.

$$Q_{cond} = \frac{Q_{evap} * COP}{(COP - 1)} \tag{3.13}$$

The space heating demand is as mentioned above the second limiting factor that defines the heat output from the EAHPs at any hour. The heat output needs to be restricted by limiting the EAHP heat output to the space heating demand. Without this constraint GAMS could choose to use more of the EAHPs capacity then needed and in the worst case run the EAHPs when there is no actual space heating demand.

The approach to finding the power limitation with respect to space heating need was to calculate the amount of space heating energy needed over a year for the planned new and refurbished buildings. The total energy could then be divided by the number of degree hours below an assumed balance temperature of these buildings. The result from this is a power signature that describes the amount of space heating power required for every °C below the balance temperature. Equation 3.14 describes the power signature.

$$P_{SH} = \frac{E_{tot,SH}}{°Ch} = \frac{kWh}{°Ch} = \frac{kW}{°C} \tag{3.14}$$

Where $E_{tot,SH}$ is the total energy needed for space heating during a year and °Ch represent the total amount of degree-hours that require space heating.

The degree hours for a year in Gothenburg where heating is needed was acquired by using the outdoor temperatures of Gothenburg in 2012 and assuming a balance temperature of 15 $°C$. The total amount of degree-hours was found to be 68 000. Figure 3.5 shows the degree hours and outdoor temperature.

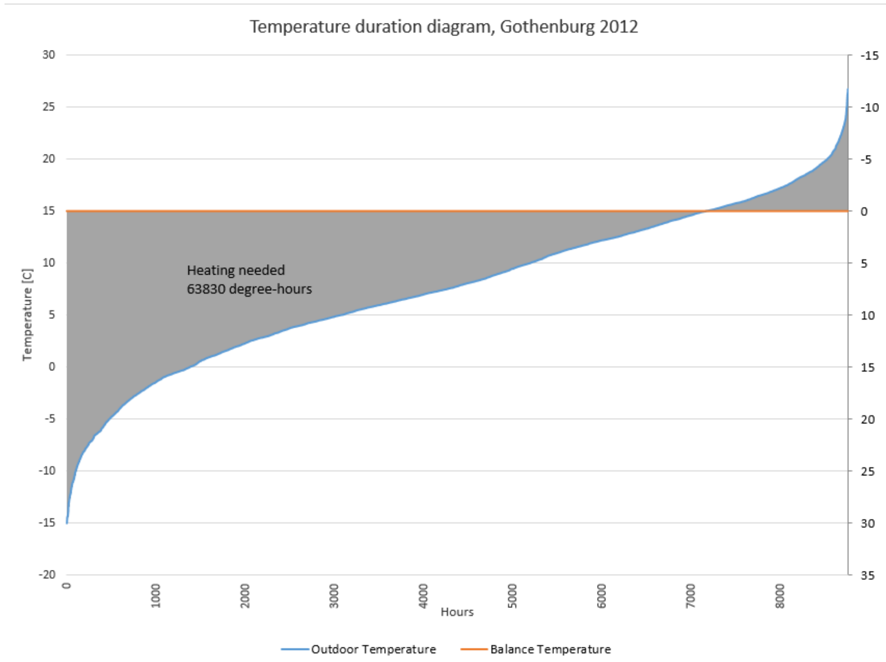


Figure 3.5: Number of degree hours below a balance temperature of 15 $°C$.

The total space heating of apartments can be calculated by using equation 3.15 below.

$$E_{SH} = e_{tot} * A_{apt} * q_{SH} = e_{SH} * A_{apt} = [\frac{kWh_{tot}}{m^2}] * [m^2] * [\frac{kWh_{SH}}{kWh_{tot}}] = [kWh_{SH}] \quad (3.15)$$

A_{apt} is the area of the apartments that will have both a EAHP and district heating connection. This area varies with the different EAHP penetration assumed in the different simulations. The average heated area of an apartment was assumed to be 100 m^2. q_{sh} is a factor describing the space heating allocation of the total energy need, this quota was set as 0.7. The specific energy need, e_{tot}, can be found for new and refurbished buildings in table 3.4 below. The space heating values are simply the product of the specific energy need and space heat quota.

Table 3.4: Specific energy need and the specific space heat. (Johnsson et al. 2016) (D. Olsson 2016b)

Building	e_{tot} $[kWh/m^2]$	e_{SHe} $[kWh/m^2]$
Refurbished	140	90
Planned buildings - norm	55	38.5
Planned buildings - low energy	30	21

The amount of apartments that will use exhaust air heat pumps together with district heating is hard to quantify and only vague suggestions of increased implementation due to low electricity prices have been encountered in literature. The number of new apartments that will be built and have a DH connection are approximated to 57 000. The amount of apartments together with an average heated area per apartment being 100 m^2 yielded a total heated area of 5.7 million m^2. A part of the total area will belong to buildings built in accordance to low energy consumption standards and the quota between low energy and regular energy standards is set to 0.2 (Johnsson et al. 2016). Furthermore a significant amount of the building stock in Gothenburg will have to undergo refurbishment and (D. Olsson 2016b) approximated the area of refurbishment to be 5 million m^2. Installing an exhaust air heat pump is usually preferred to do while constructing a new building or while already performing extensive refurbishment work. Following from this is that the potential amount of apartment area that could be suitable to utilize a EAHP is about 10.7 million m^2.

Five deployment levels of EAHP were modeled. These levels were defined as a percentage of new and refurbished apartment area that has an installed capacity of EAHP. The amount of generation capacity and space heating that is required varies with every hour since the temperatures and COP values are changing but the average amount of available space heating power is shown in table 3.5 together with the power signature for space heating demand for the modelled penetration levels.

Table 3.5: Average capacity of heat pumps at different deployment levels.

% of apt. with EAHP	Total average EAHP capacity [MW]	P_{SH} [kW/°C]
100	85,6	7980
50	42,8	3990
30	25,7	2394
20	17,1	1596
10	8,6	798

At -16 °C the power coverage of the EAHP is about 23%. The reason for this value being a bit higher than found in literature is believed to stem from the fact that this simulation is carried out on a mix of new and old buildings with new state of the art heat pumps deployed. New buildings will have less space heating demand and new heat pumps are more effective than older ones.

The two limiting space heating values, Q_{EAHP} and Q_{SH}, are calculated for every hour outside of GAMS and the lowest of the two is only considered. The final constraint regarding the power output of the EAHP is:

$$Q_{EAHP} \leq Q_{EAHP,min} \quad \forall t \tag{3.16}$$

where $Q_{EAHP,min} = \min(Q_{EAHP}, Q_{SH})$

3.3.5 Heat Source Shifting

In section 2.6.1.1 the concept of heat source shifting with exhaust heat pumps and district heating is presented. As an addition to model the EAHPs effect on the future DH-system also two different control schemes of the EAHPs were examined and applied to the different penetration levels of EAHP. The two different control schemes are prioritized control and heat source shifting. Prioritized control allows the EAHP to deliver its maximum capacity and is only limited by the space heating demand. This is the traditional way of controlling the heat pumps where the actual electricity price is not considered when choosing to operate or not. The second control scheme, heat source shifting, is a more sophisticated way of controlling the heat pumps. The hourly electricity and heat prices are compared in order to use to heat source that is the most cost optimal in every hour.

The simple constraint in GAMS for prioritized control is shown below. The constraint makes sure that the heat pump is run when space heating is needed no matter the running cost for the actual hour.

$$Q_{EAHP,Prio} = Q_{EAHP,min} \quad \forall t \tag{3.17}$$

The generation constraint for heat source shifting is the same as equation 3.16. The constraint implies that the heat pump generation can vary between zero and the minimum of $Q_{EAHP,min}$, depending on the actual running and marginal costs for every hour.

3.4 Combinations of scenarios

In addition to examining each possible scenario by itself, some plausible combinations of the different scenarios were studied. The combinations that were studied are:

- Buildings used as TES and distributed heat pumps
- Accumulator tank, buildings used as TES and distributed heat pumps

These scenarios are studied because it is deemed that they are plausible to be implemented at the same time. The scenario that more distributed heat pumps are used in the heating sector is a scenario where Göteborg Energi is not a direct stakeholder. Therefore it is plausible that any of the storage scenarios may become reality at the same time as the share of distributed heat pumps increases. It is not very likely that an accumulator tank *and* a seasonal storage are constructed, since both are associated with high investment costs. Utilising buildings as TES has a much lower investment cost, and it is not unlikely that it may be implemented together with an accumulator tank.

3.5 Sensitivity Analysis

When modeling a future energy system, many assumptions regarding the model setup and input have to be made. With these assumptions uncertainties arise which all affect the accuracy of the modeling work. A few sensitivity analyses are performed in order to quantify and observe how the models react to changes regarding certain assumptions. The sensitivity analyses in this thesis are performed for one parameter at a time in order to see how a certain change in assumptions would influence the results. All of the assumptions have not been tested through sensitivity analyses. The variables and assumptions that were investigated are summarized in the following list:

- The price of bio gas

- No construction of a new bio-fuelled CHP
- Price of electricity certificates

A reason for performing a sensitivity analysis on the price of bio gas was to evaluate the heat generation from bio gas and especially see how the operation of Rya CHP would be affected by different bio gas costs. The price of bio gas was first set at an average price between the lower, 500 SEK/MWh_{fuel}, and upper, 900 SEK/MWh_{fuel}, cost boundary found through a literature review. Two sensitivity analyses were performed in order to assess the impact of the bio gas price, the first used the low fuel price of 500 SEK/MWh_{fuel} and the second used the high price of 900 SEK/MWh_{fuel}.

A sensitivity analysis that aimed to asses the influence of building the new bio-fuelled CHP or not was also carried out. In this sensitivity analysis the average price for bio gas was still used. Finally the last sensitivity analysis was performed on the price of electricity certificates. Two analyses were performed; one that used a certificate price of 0 SEK/certificate and another, which increased the certificate price to 350 SEK/certificate.

4

Results

The results of all performed optimisations are presented in this chapter. There are a number of uncertainties associated with modelling of future energy systems such as fuel costs, taxes and so on. Therefore, it is not sensible to examine e.g. total costs in absolute terms. Rather, the relative cost reductions compared to the proposed base case are to be studied. First, the results from optimisations of the base case are presented. These results are used as a base line that all other scenario related results are compared with.

4.1 Base Case, 2032

The heat generation plants in service 2012 was kept in the model to 2032 but with some changes made to fuel usage. All natural gas was replaced by bio gas with a higher fuel price but with zero CO_2 emissions. Furthermore, a biomass-fuelled CHP plant was introduced in order to reflect the ambitions of a future cost effective and carbon neutral district heating system in Gothenburg, see 3.2.1 and 3.2.1.1 for details on the new CHP and the substitution of natural gas.

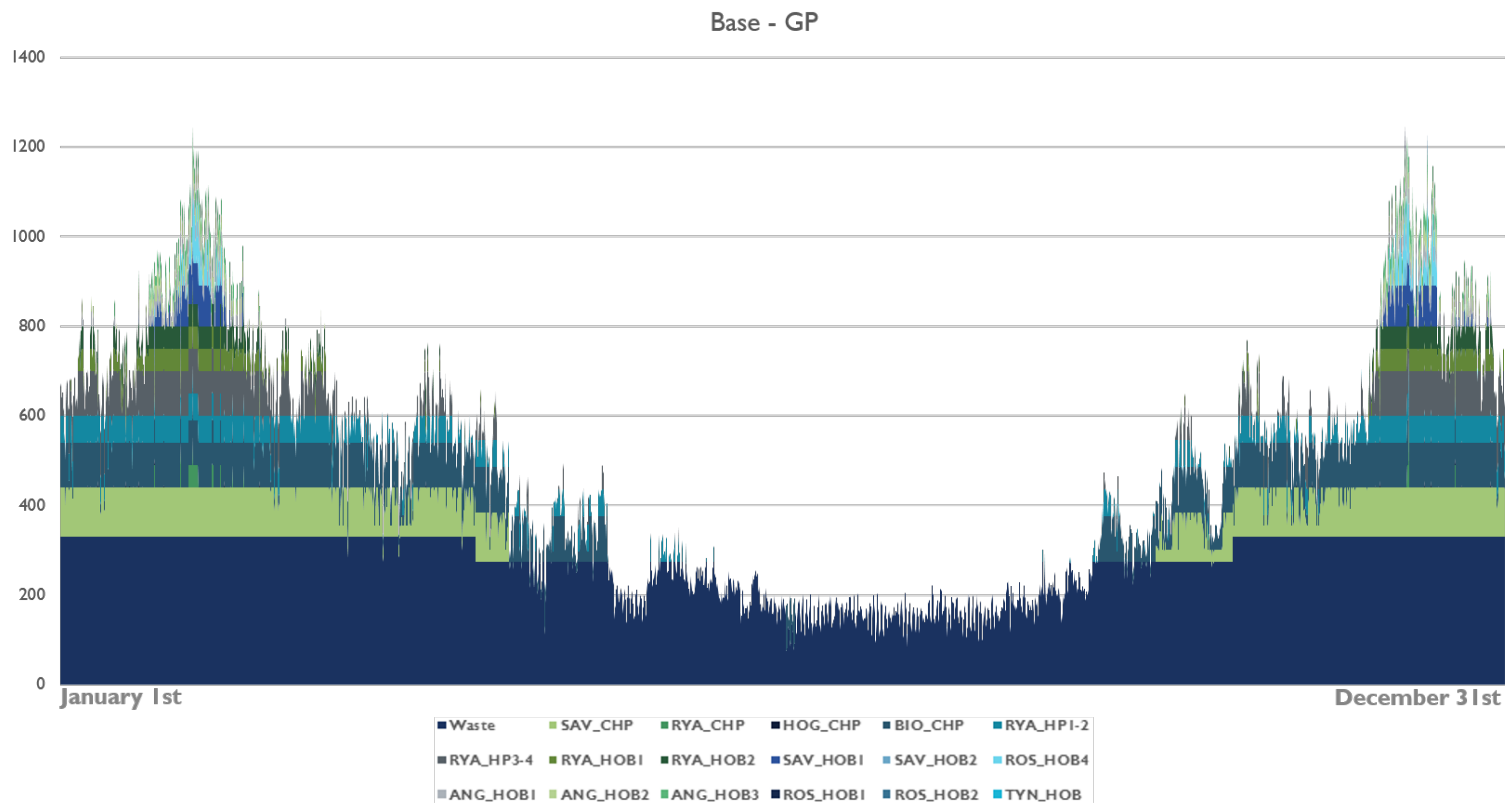


Figure 4.1: Dispatch of heat generation units in the base case scenario.

4.1.1 Total system running costs

In this thesis the total system running costs are defined as the cost for generating heat deducted by the revenue from selling the electricity that is being co-generated in the CHP plants. The total system running costs for the base case acts as the foundation for comparing the running costs of the other scenarios. See table 4.1 for an overview of the total system running costs with respect to the three electricity scenarios, see section 2.4 for information on the electricity scenarios. Note that these numbers are only to be regarded as a foundation for comparison, the absolute numbers are highly uncertain.

Table 4.1: Total system cost for base cases.

Scenario	System cost [MSEK/yr]
Green Policy, GP	439
Regional policy, RP	465
Climate Market, CM	436

Table 4.1 shows that two of the electricity scenarios, GP and CM, result in very similar total system costs while the RP-case is more expensive. The electricity price have a significant impact on the operation of CHP plants and heat pumps. Electricity generated and sold in CHPs reduce the cost of generating heat and low electricity prices reduces the cost for operating a heat pump.

4.1.2 Heat generation

The heat generated by each plant category can be seen in figure 4.2. Industrial excess heat and municipal waste heat are grouped in to excess heat. The HOBs and CHPs that run on the same fuel are for illustrative purposes grouped together.

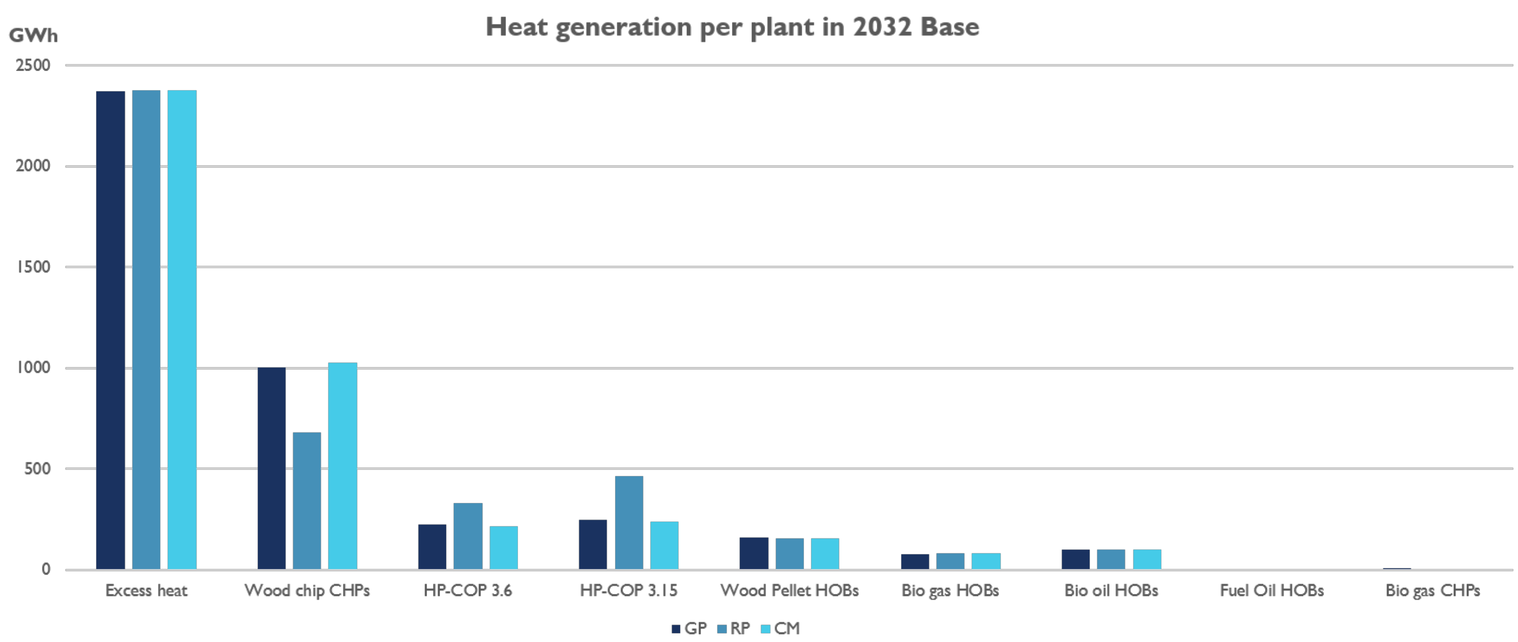


Figure 4.2: Heat generation per plant and fuel type in 2032 for all three electricity scenarios.

Figure 4.2 shows that the different electricity scenarios in principle only have an impact on the use of CHP plants and heat pumps. This is not surprising, since these are the two heat generation technologies in the DH system that have a connection to the electrical system. GP and CM are scenarios where the price of electricity is higher, and therefore CHP plants are used more in these scenarios, since there will be more hours during the year where the revenue from electricity sales will make it profitable to run CHP plants. On the other hand, RP is a scenario where electricity price is generally lower and therefore heat pumps are more utilized in this scenario. This behaviour can be seen clearly if one examines the use of the wood chip CHPs and the heat pumps. The use of the bio-CHP is roughly halved in the RP scenario compared to GP and CM. The heat is instead generated by the heat pump, the average electricity prices can be seen in Table 2.2.

The heat generation from the Rya CHP plant is presented in detail in table 4.2, also the decrease in heat generated compared to 2012 is shown as a percentage. It is interesting to study the operation of Rya CHP in detail, since it is a large plant (generates 15% of annual heat load) that is relatively newly constructed at a large investment cost. It is desirable that this plant is used to a large extent of its capacity.

Table 4.2: Generated heat from Rya CHP in base case.

Scenario	Generated heat [GWh]
GP	5.944 (-99.0%)
RP	0 (-100%)
CM	1.217 (-99.8%)

It can be clearly seen in the table above that Rya CHP is used to little extent. Rya made up for 15 % of the heat generated in 2012 and the shares in 2032 is reduced by 99-100%. The share of heat that stems from different fuels are interesting to look at in the future scenarios as well and this is visualized below in figure 4.3.

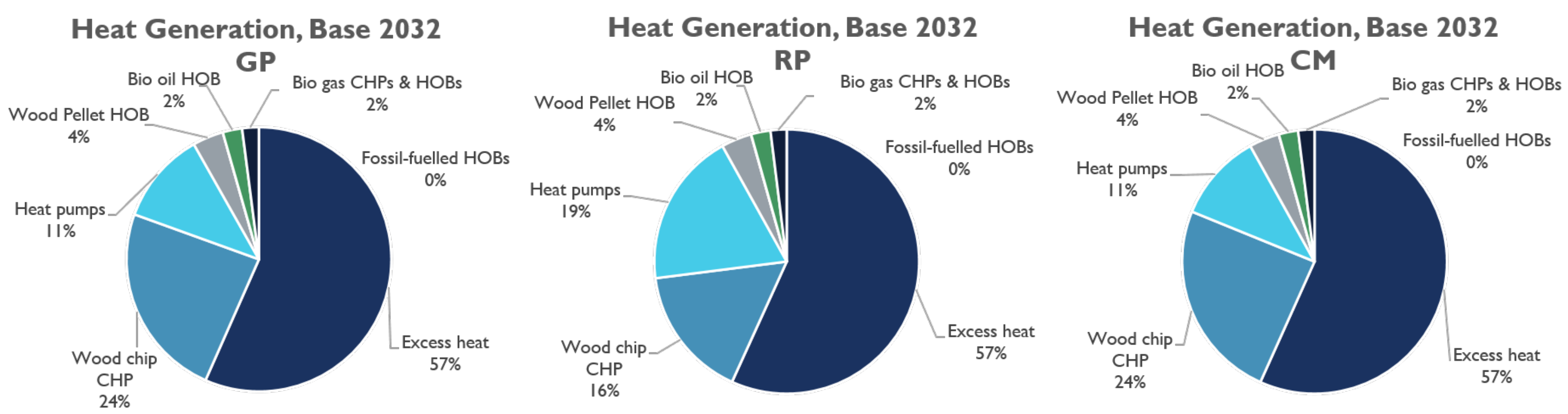


Figure 4.3: Share of heat generation from different fuels in the three electricity scenarios.

The majority of heat generation still stems from waste incineration plants and industrial waste heat as it did in 2012. However, the substitution of natural gas to bio gas and the construction of a biomass-fuelled CHP have drastic impact on the fuel shares. The natural gas substitution decreases Rya CHPs production significantly and just a small part of the heat generation comes from bio gas. The share and amount of wood chip usage increases with the new CHP as it is operated before Rya. Further the influence of the different electricity scenarios can be identified, If the electricity price is lower more heat is going to be generated in the large industrial heat pumps and less is generated in the wood chip CHPs.

4.2 Hot Water Accumulator Tank

By adding a hot water accumulator tank to the DH system in Gothenburg, peak loads can be reduced throughout the entire year. Figure 4.4 shows a comparison of the heat generation dispatch between the base case in 2032 and the dispatch when an accumulator is added. The dispatch is only shown for the Green Policy-scenario. The differences between the three electricity scenarios are too small to be seen in a dispatch graph of this scale. Excess heat includes heat from the refineries ST1 and Preem as well as heat from municipal waste incineration at Renova.

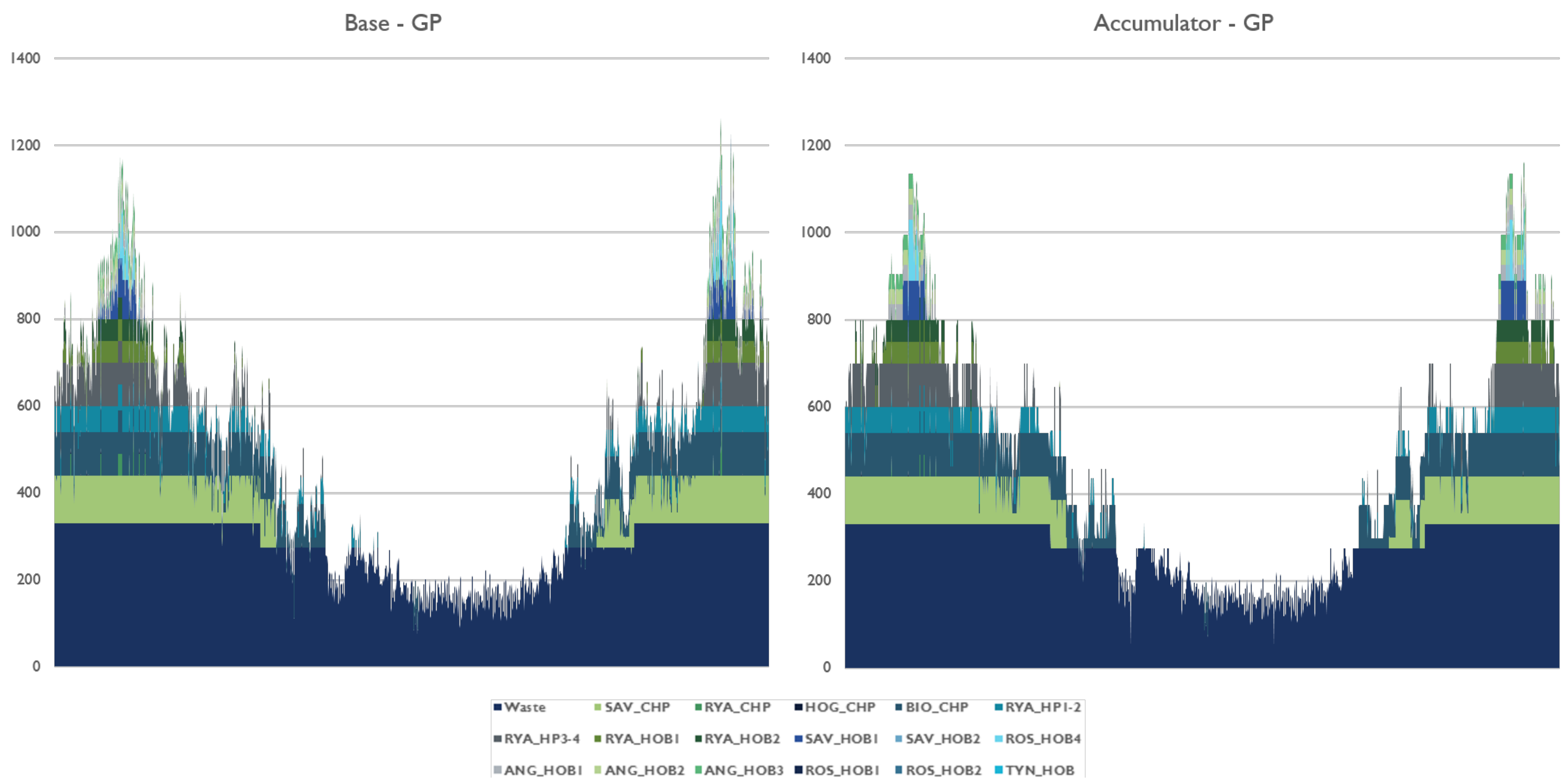


Figure 4.4: Heat generation dispatch for electricity scenario GP. Left: base case. Right: with accumulator storage

It can be seen from Figure 4.4 that the accumulator reduces the demand for heat in peak hours. This is most clear in the hours with the highest demand, compare the maximum values in the two graphs in the figure. In order to reduce the demand in these hours, the accumulator needs to be charged. When the demand is lower, and therefore the marginal cost of generating heat is lower, the generation is increased. This can be seen in the graphs as the valleys in the demand have been filled in the case with an accumulator, which is to be expected. Overall, the difference in dispatch is subtle, but this is not unexpected since the power capacity of the accumulator tank is not very large in comparison to the total heat demand. It may be difficult to properly asses the performance and impact of the accumulator by merely looking at dispatch diagrams such as these. Therefore, additional means of evaluation are used in this report, such as system cost savings, heat generation by primary fuel and the total discharged heat from the accumulator.

4.2.1 Total system costs

In Table 4.3, the difference in total system costs when an accumulator tank is added to the system are presented. The cost savings are presented for each of the three different electricity scenarios. Total system costs in this context refers to running costs including start up costs after electricity sales. No investment costs are taken into consideration. Since the absolute numbers of the costs are uncertain, only the cost difference compared to the base case are studied.

Table 4.3: Total system cost difference compared to base case

Scenario	Cost difference [MSEK/yr]
GP	-8.84 (-2.0%)
RP	-7.33 (-1.6%)
CM	-8.20 (-1.9%)

The cost savings are all in the range of 7-9 MSEK per year. This can be compared to an estimated investment cost of 50-100 MSEK which would indicate a payback period of approximately 5-15 years, depending on investment cost and electricity scenario. Note that these payback periods does not take any discount rate in to account.

The cost savings are smallest in the RP scenario. The RP scenario has the lowest average electricity prices of the three electricity scenarios and therefore, CHP plants are run less and heat pumps are more favored. This means that the revenue from electricity sales is lower, and more electricity is instead bought to generate heat. In fact, the cost for generating heat before subtracting revenue from sold electricity is actually lowest in the RP scenario. Since more heat is generated by heat pumps, less total input energy is used in the system, because heat pumps uses less electricity to generate one unit of heat than what a CHP uses fuel. The cost savings are achieved by avoiding start up costs and by avoiding the use of HOBs with high running costs through the use of the accumulator tank.

4.2.2 Heat generation

In Figure 4.5, the total amount of heat generated by each heat generation plant is shown. The plants are grouped by their primary fuel, see Table 2.1 for reference. The new bio CHP is included in the category wood chip CHPs. For readability, only the results of the GP electricity scenario are presented. The difference in generated heat between the different electricity scenarios when an accumulator is added to the system are very similar to those in the base case. Also included in the figure is the amount of heat that has been discharged from the accumulator tank during the modelled year. The total amount of generated heat in all scenarios is around 4.3 TWh, which is more than in the base case. This is explained by the fact that there are losses in the accumulator storage that increases the total demand for heat.

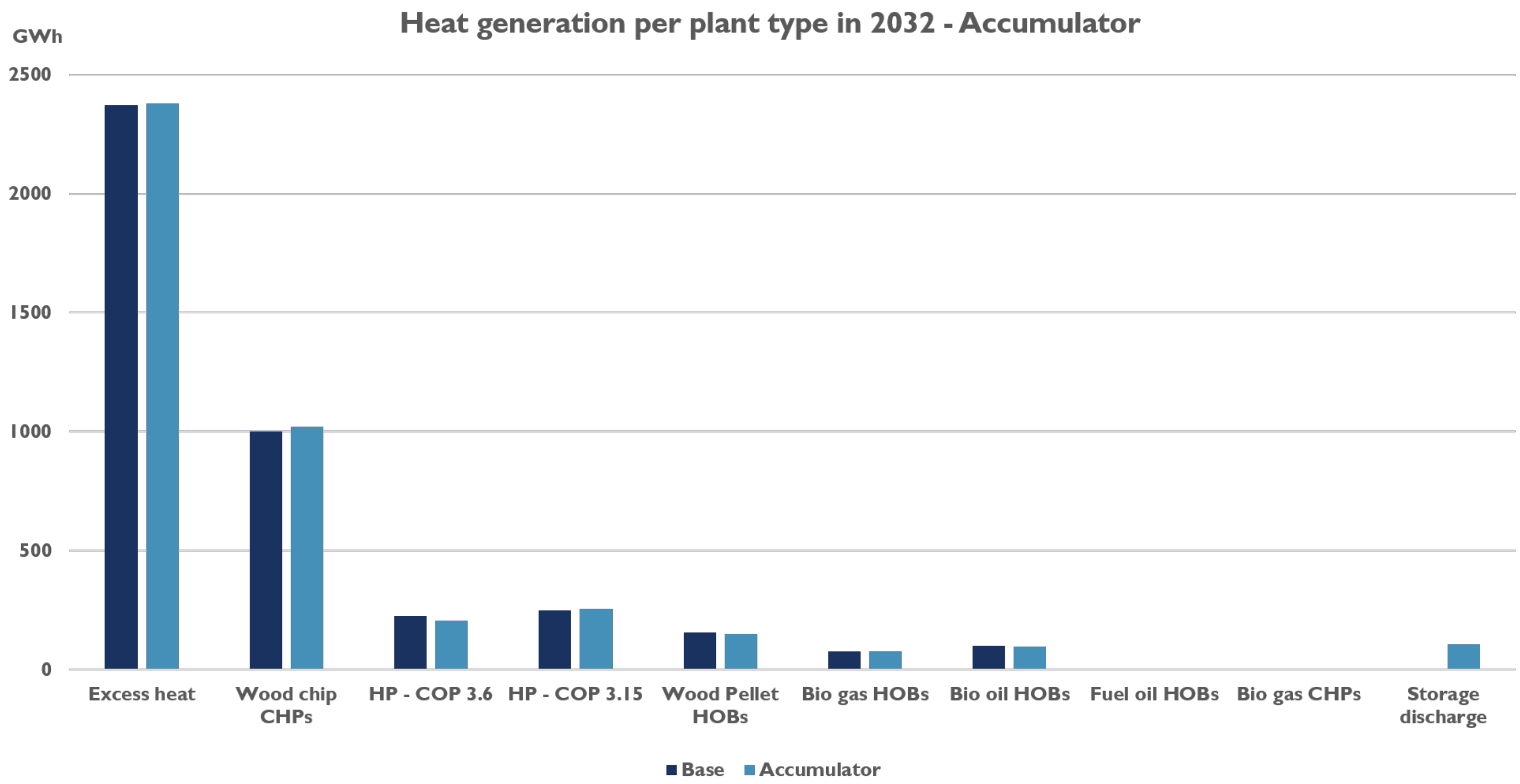


Figure 4.5: Total heat generation in 2032 in electricity scenario GP, by primary fuel/heat generation plant type. The total amount of generated heat is around 4.3 TWh

It can be seen in Figure 4.5 that use of excess heat is more or less unchanged when an accumulator is added to the system. The excess heat is already used to its full extent during winter months, and the only way to increase its use is by taking advantage of it during summer months. Since the accumulator has a loss factor, it cannot store heat from summer to winter, and therefore excess heat is used directly during summer instead.

The wood chip CHPs generates more heat when there is an accumulator available than in the base case. This means that the accumulator to some extent has been used as a heat sink for the CHPs, i.e. that electricity has been produced when there is no demand for heat and the generated heat has been stored in the accumulator. The increase in heat generation from CHPs is to some extent made on behalf of lowered heat generation from heat pumps.

The use of all types of HOBs is decreased when the accumulator is made available. No fuel oil is used, so the generation of heat is indeed completely free of direct CO_2 emissions. One can of course discuss whether or not the excess heat and electricity is CO_2-free. The heat generated from bio gas CHPs is in fact not zero, but very close to it, in relation to all other heat generation.

It is of interest to study the heat generation from the Rya CHP in detail, since it is an existing plant, which is far from the end of its technical and economic lifetime. Therefore one would like to put it to as much use as possible. However, the results of the optimisations in this thesis show that Rya CHP is not used much in a future scenario. The heat generation from the Rya CHP plant is presented in detail in Table 4.4.

Table 4.4: Generated heat from Rya CHP with accumulator storage in system

Scenario	Generated heat [GWh]
GP	1.866(-99.7%)
RP	0 (-100%)
CM	0.885 (-99.9%)

It is clear that Rya CHP is only very seldom used in a future scenario. If electricity prices are low, as in the RP scenario, Rya CHP is not put into operation at all during a year if an accumulator is added to the DH system. Compared to the base case, the use of Rya CHP have decreased. Likely, the storage has been charged with heat from the Bio CHP. When that heat has been discharged, it has replaced heat that would have been generated in Rya CHP otherwise.

4.2.3 Storage

The use of the accumulator storage tank can be measured by the amount of heat that has been discharged during the year. This is presented in Table 4.5.

Table 4.5: Total discharged heat from the accumulator storage during a year

Scenario	Discharged heat [GWh]
GP	105.8
RP	90.3
CM	94.9

It can be seen that the accumulator is used less in the RP scenario than in the GP and CM scenarios. Also, the accumulator is used the most in the GP scenario. One reason for this behaviour is the fluctuating electricity prices of the different scenarios. As described in 2.4, RP is a scenario with very low fluctuations in electricity price, whereas CM and, in particular, GP shows a large spread in electricity prices both during 24 hours and over the entire year. With larger fluctuations of the electricity price, the benefits of a storage in the DH system are larger, since one can make even more use of the principle "charge at low cost - discharge at high cost". The storage capacity of the tank is 1 GWh, so the storage tank is used for 90-105 full water changes in a year, depending on electricity scenario.

4.2.3.1 Charge/discharge cycles

The accumulator tank is not being used during the warmer periods of the year, when the demand for heat is low and there is enough waste heat available to cover the entire demand. This can be seen in Figure 4.6, where the state of charge in the accumulator is plotted for every hour of the year in the GP scenario.

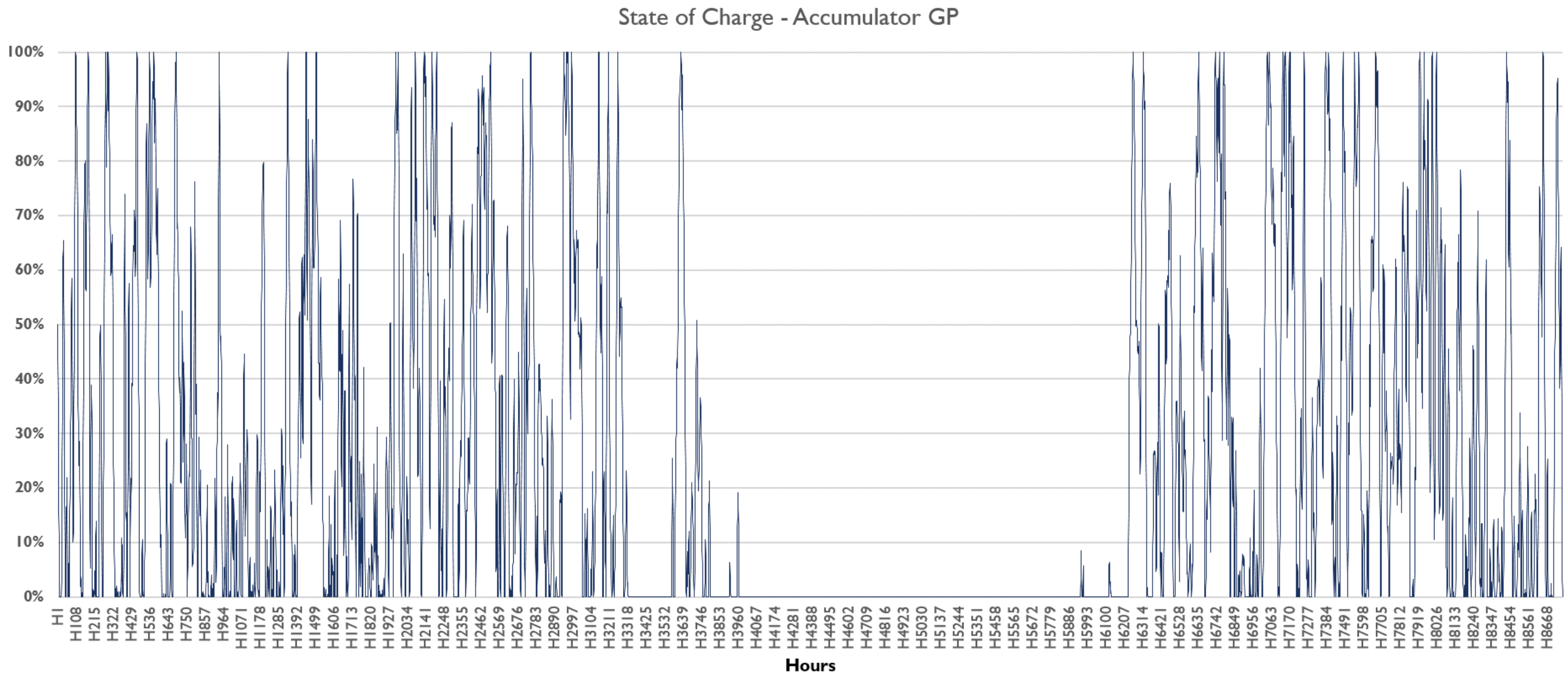


Figure 4.6: State of charge of accumulator tank storage during a year in GP scenario

This can be seen as a verification that the optimisation of the storage is plausible, since this is how an accumulator tank could have been operated in practice. Since there are heat losses in the accumulator there is a cost associated with using the accumulator. Therefore, during summer months when the available excess heat is enough to cover the entire heat demand, no heat is stored in the accumulator. If there were no heat losses in the accumulator, one could in theory charge and discharge the storage every other hour during summer. Figure 4.7 shows the state of charge in the accumulator during a week in March together with the heat demand.

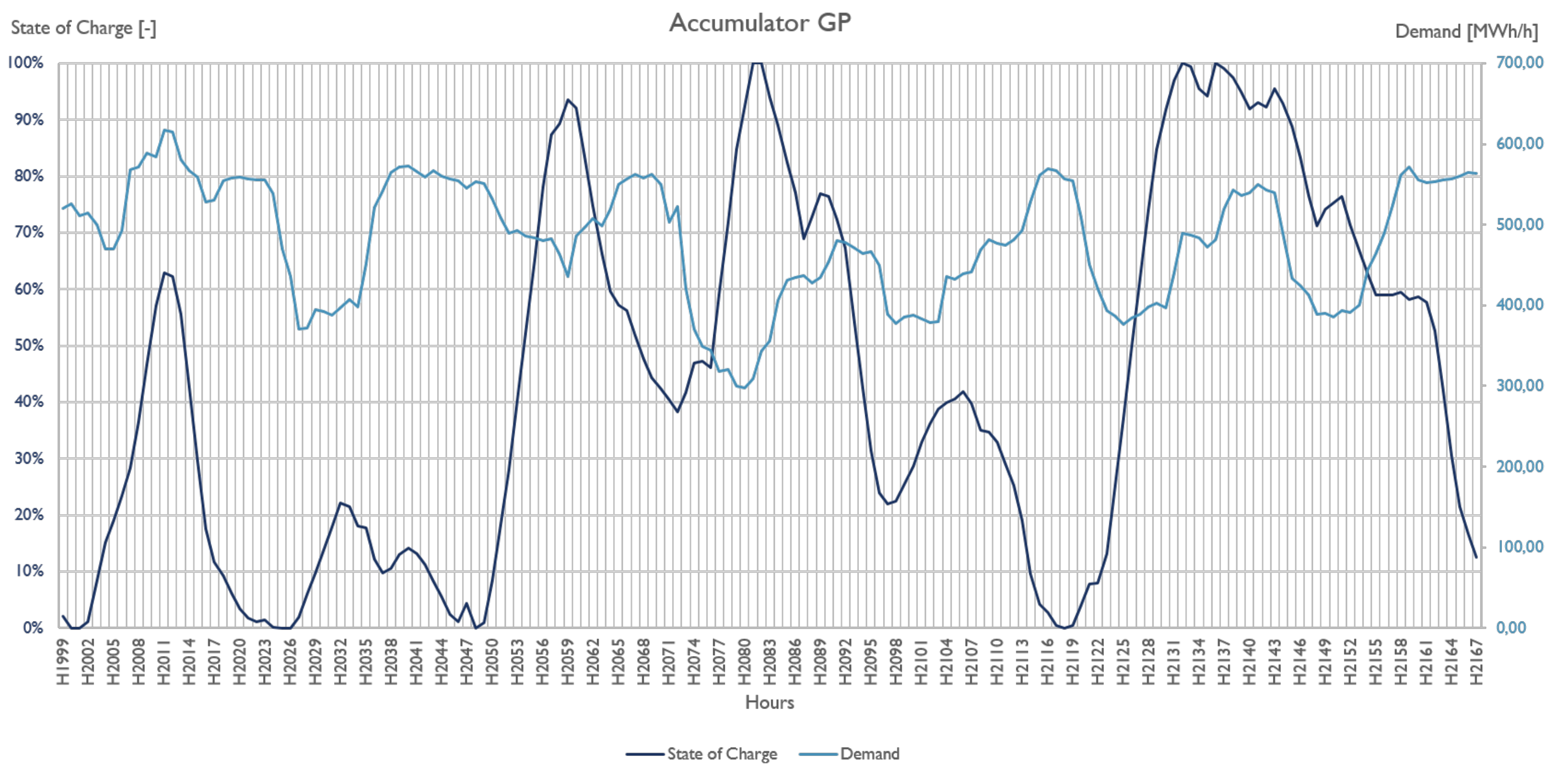


Figure 4.7: State of charge of accumulator tank storage during a week in March, together with the demand for heat

It can be seen in Figure 4.7 that the accumulator is discharged when there are peaks in the demand. In principle, the valleys of the state of charge of the accumulator corresponds to the peaks of the demand. Looking back at Table 4.5, the storage tank is used for roughly 100 cycles during a year. The time period during summer when the storage tank is not used at all is roughly 2000 hours or 12 weeks. This means that the storage is fully charged and discharged a little more than twice a week on average during the heating season. This shows that the accumulator is not only used as storage from day to day, but also stores heat over several days. The operation of the accumulator is depending on two main factors; the price of electricity and the demand for heat. The price of electricity decides whether to charge or discharge the accumulator both by being very high or very low. In hours where the electricity price is very high, CHPs are run and stores heat in the accumulator in order to increase revenue from sold electricity. On the other end of the scale, when electricity prices are low, heat pumps are used to charge the accumulator. The charged heat from low-price hours can later be used when the electricity price is higher again, and the total system cost is thus decreased. The demand for heat of course has an impact on the operation of the accumulator, which have been described earlier. From the results presented here, one can also draw the conclusion that the demand and the electricity price in combination have a large impact on the operation of the accumulator. For the accumulator to be charged with heat from a CHP, the electricity price must be low, as well as the demand for heat.

4.2.4 Heat load variation

It was seen in Figure 4.4 that peak demand were decreased and demand valleys were filled through the use of the accumulator tank TES. In order to asses the impact of this, the average daily heat load variation were studied, comparing the base case with the case of an accumulator TES. The relative daily variation in heat load is presented in Figure 4.8. Also shown is the relative daily heat load variation for the base case, for comparison. The heat load in the accumulator case is defined as the sum of all generated heat in every hour, excluding the charge/discharge to/from the accumulator.

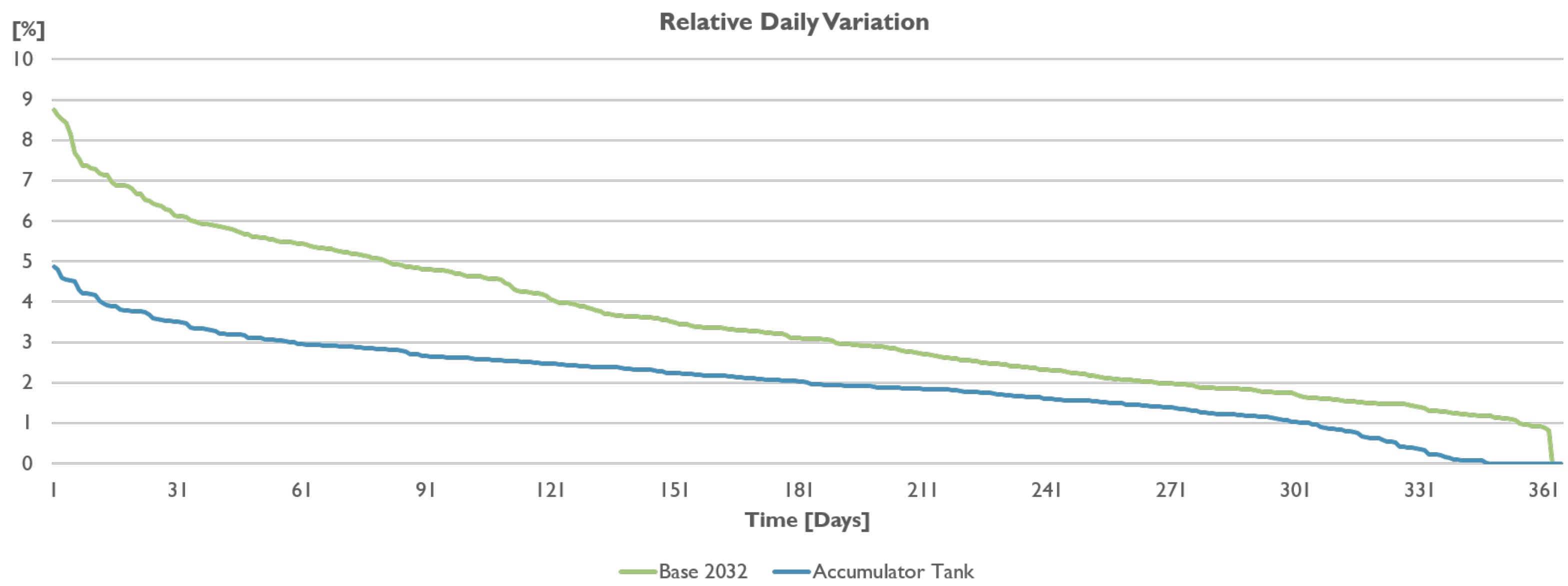


Figure 4.8: Relative daily heat load variation with accumulator and in base case

It is clear from Figure 4.8 that the relative daily heat load variation decreases substantially when an accumulator tank is used as TES. The maximum variation is decreased from around 9 % to 5 % and there are around 20 days where the variation is 0 %. These days occur when there is capacity available in the heat generation plant that is on the margin during an entire day. The output from this plant is then increased to its maximum and the heat is stored in the accumulator. The load profile becomes entirely flat and the hourly load values becomes equal to the daily average which makes the variation zero. These periods can also be seen in the dispatch shown in Figure 4.4 above, where there are periods where there are blocks of constant heat generation. Because of the lower variation in heat load, the number of start ups of generation plants have been reduced and the operation of all plants have become smoother so that the need for maintenance may have been reduced.

4.3 Buildings as Thermal Energy Storage

The results of utilizing buildings as thermal energy storage on a large scale are similar to the results of introducing an accumulator tank storage. A comparison of the heat generation dispatch in the year 2032 between the base case and when building TES is used is shown in Figure 4.9.

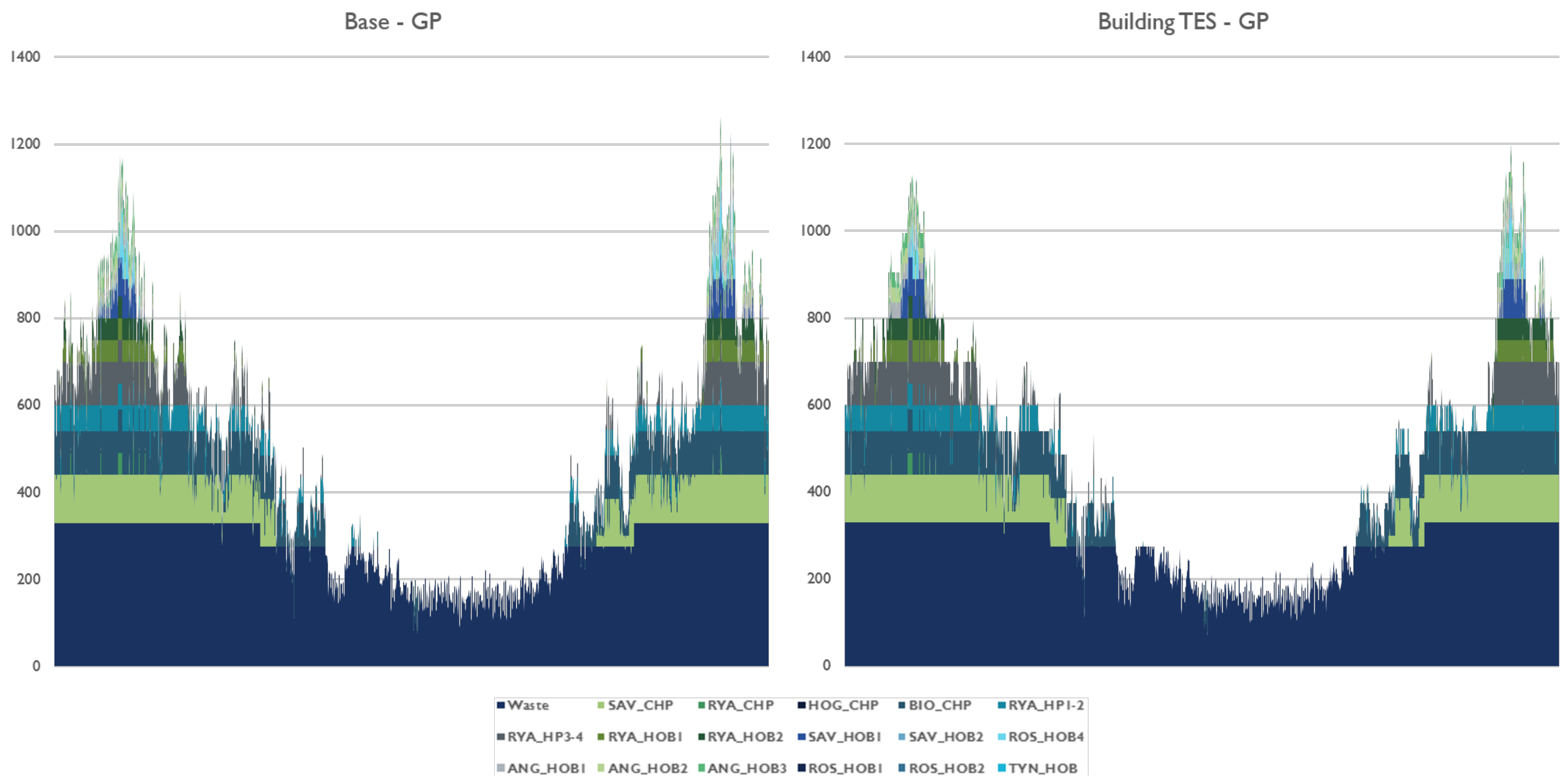


Figure 4.9: Heat generation dispatch for electricity scenario GP. Left: base case. Right: with building thermal energy storage

The dispatch of heat generation when buildings are used as TES is quite similar to when an accumulator is used as TES. This is to be expected, as both are examples of short term TES. The difference between the two is that the highest peaks in heat generation are decreased less with building TES than with an accumulator, since the power capacity of the buildings is smaller than for the accumulator. However, the total storage capacity is larger in the buildings than in the accumulator, so that more energy can be discharged over a year from buildings than from an accumulator.

4.3.1 Total system costs

In Table 4.3, the difference in total system costs when buildings are used as TES are presented. The cost savings are presented for each of the three different electricity scenarios.

Table 4.6: Total system cost difference compared to base case, with building TES

Scenario	Cost difference [MSEK/yr]
GP	-9.75 (-2.2%)
RP	-8.42 (-1.8%)
CM	-9.75 (-2.2%)

The cost savings achieved when using buildings as TES are comparable to the savings achieved with an accumulator tank. The cost savings from building TES are somewhat larger than for an accumulator. This can be explained by the facts that the storage capacity of the buildings is larger and that the building storage is modelled without any heat losses. The cost savings in all three scenarios lie between 8 and 10 MSEK/year, which can be compared to the estimated investments costs of 12 MSEK. If one neglects any discount rate, the payback period for using buildings as TES would be roughly 1-1.5 years. The savings are smaller in the RP scenario, since electricity prices are lower in this scenario than the other two, so that CHP units sell less electricity. In all electricity scenarios, the total cost of heat generation during the year is actually higher for the building case than for the accumulator case. However, since more electricity is produced from CHPs in the building case, the total cost after selling electricity is lower. This would indicate that the building TES acts even more as a heat sink for CHPs than what an accumulator does.

4.3.2 Heat generation

The difference in total heat generation per plant between the accumulator case and the building case is not very large. Figure 4.10 shows the total heat generation per plant in the GP electricity case when buildings are used as TES together with the heat generation in the base case and the same figures for the accumulator case. Compared to the accumulator case, some more heat is generated in all CHP plants, and HOBs are used slightly less. The total amount of generated heat is around 4.3 TWh, which is the same as in the accumulator case.

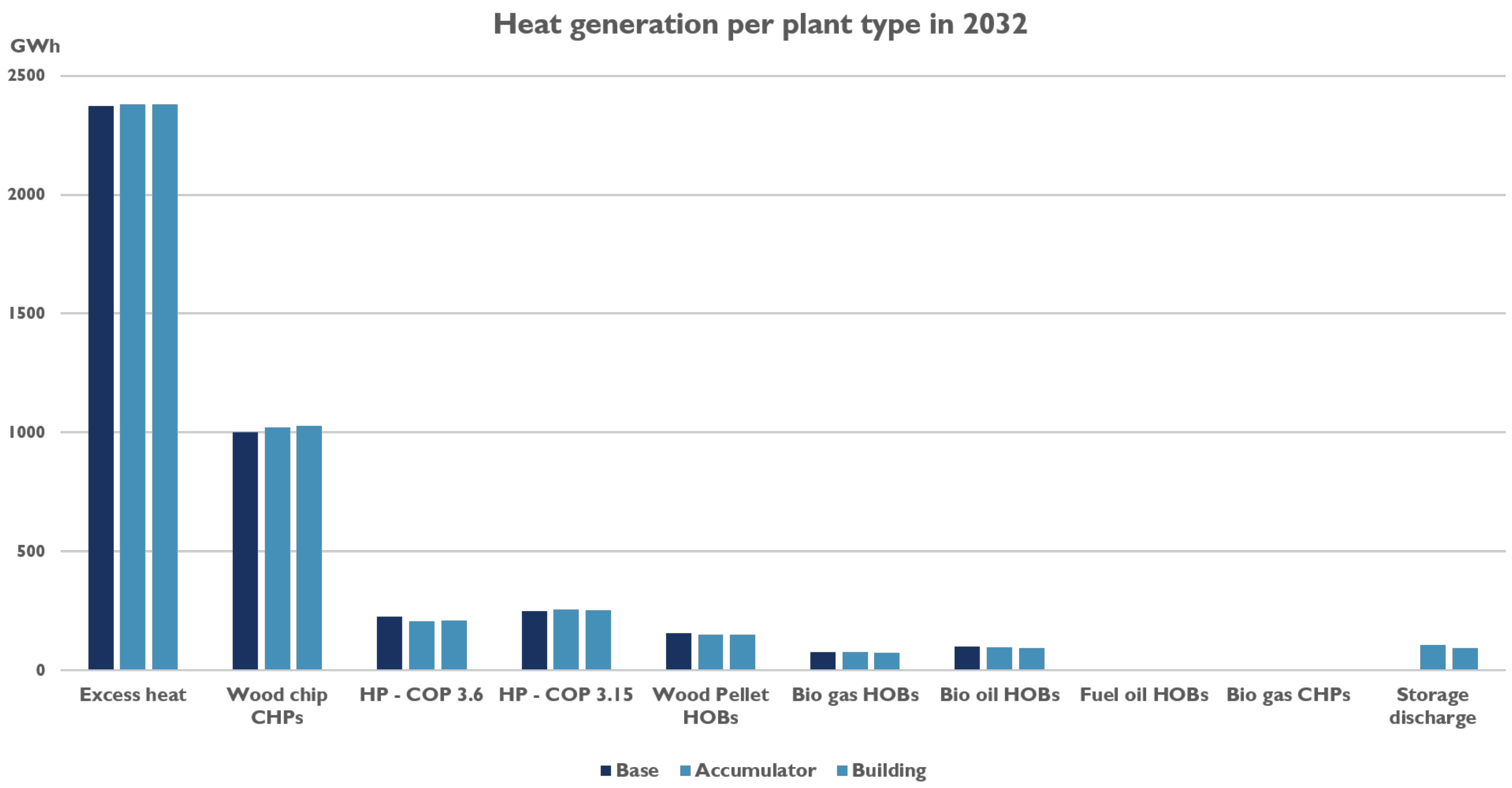


Figure 4.10: Total heat generation in 2032, electricity scenario GP. The heat generation for the base case, the accumulator case and the building storage case are shown.

Again, following the discussion regarding system cost above, the building storage is used more as a heat sink for CHPs than what an accumulator does.

Examining Rya CHP in detail again, one finds that it is being used slightly more when buildings are used as TES than with an accumulator in the system. Still, it is used very seldom and generates only 0.11% of the total heat in the system in the most favorable electricity scenario. This can be compared with the share of heat generated in Rya CHP in 2012, which was 15%. See Table 4.7 for details.

Table 4.7: Generated heat from Rya CHP with buildings used as TES

Scenario	Generated heat [GWh]
GP	4.841 (-99.2%)
RP	0 (-100%)
CM	1.008 (-99.8%)

Again, when electricity prices are generally low, Rya CHP is never put into operation during a year.

4.3.3 Storage

The total amount of heat that is discharged from buildings used as TES is presented for all electricity scenarios in Table 4.8. This is the heat that has been discharged from the shallow storage, which is the heat that is made use of in the DH system.

Table 4.8: Total discharged heat from buildings used as TES during a year

Scenario	Discharged heat [GWh]
GP	93.7
RP	88.1
CM	90.5

In general, less heat is discharged from the building shallow storage than from an accumulator. This is likely due to the fact that the discharge capacity of the buildings is lower than for the accumulator. When making an estimate of how many charging cycles are performed in building TES, it is important to remember the deep storage as well. Only looking at the shallow storage, which has a capacity of 278 MWh, the shallow storage is used for about 330 full storage cycles in a year. However, if one considers the entire storage capacity by adding the deep and shallow storage capacity together as $278 + 1758 = 2036\ MWh$, the entire storage is instead used for 50 full cycles in a year.

The state of charge in the shallow and deep storage during the year are presented in Figure 4.11 and 4.12 below. The state of charge is only shown here for the GP electricity scenario.

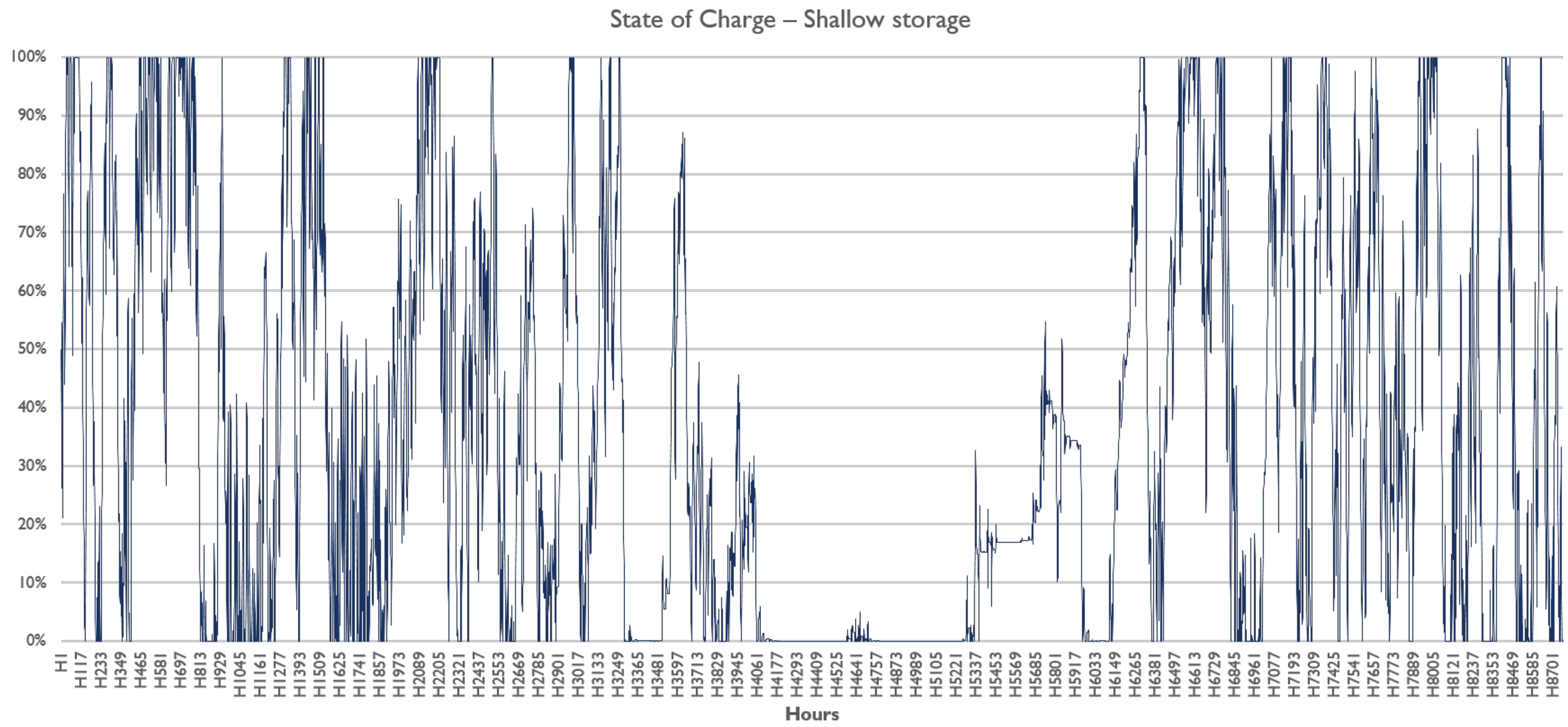


Figure 4.11: State of charge of shallow storage in buildings during a year in GP scenario

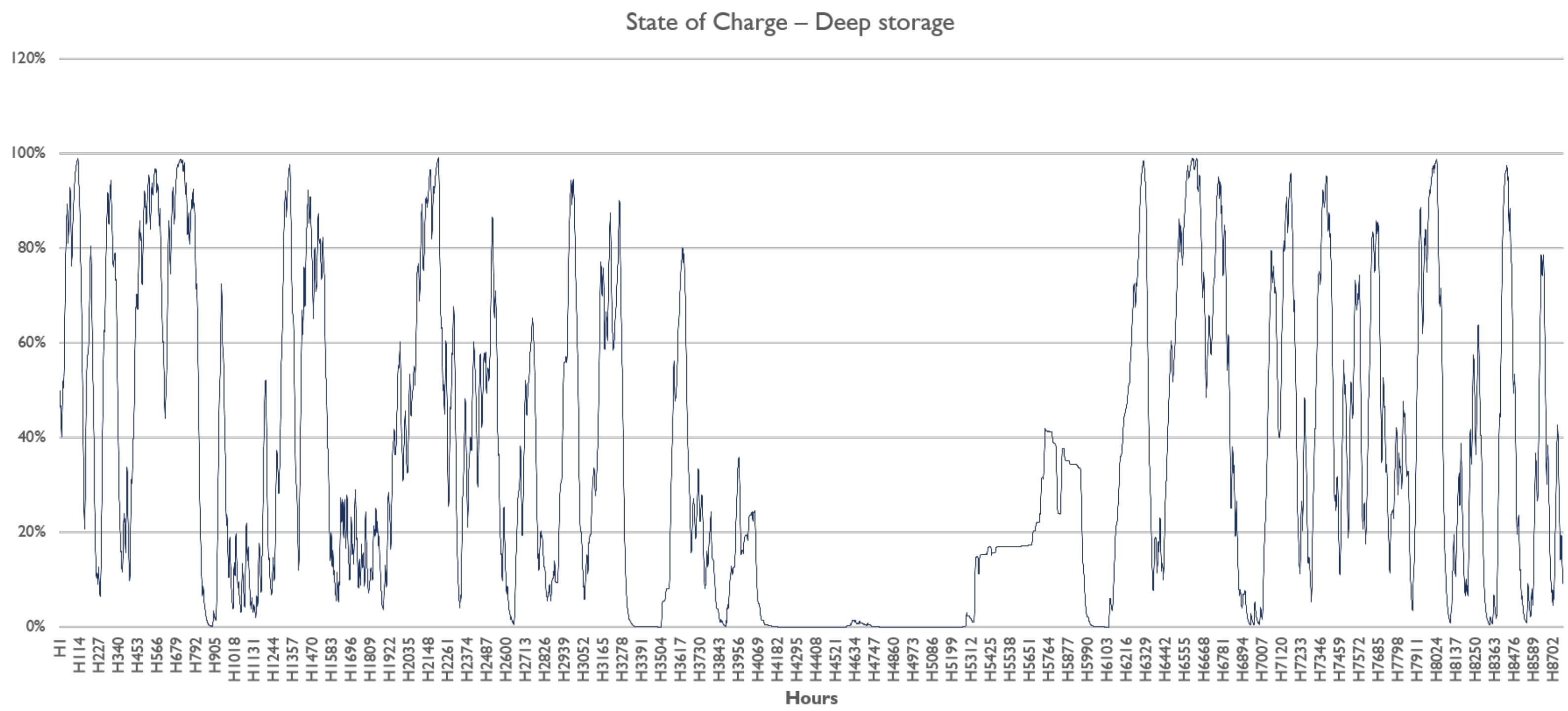


Figure 4.12: State of charge of deep storage in buildings during a year in GP scenario

It can be seen that the deep storage follows the behaviour of the shallow storage with a time delay. The storage is used to a higher extent during summer months than what an accumulator does, mainly because there are no losses modelled in the building storage.

The state of charge of both storages are plotted together with the hourly heat demand for a week in March in Figure 4.13. This is the same week that was shown for the accumulator storage in Section 4.2.3.1.

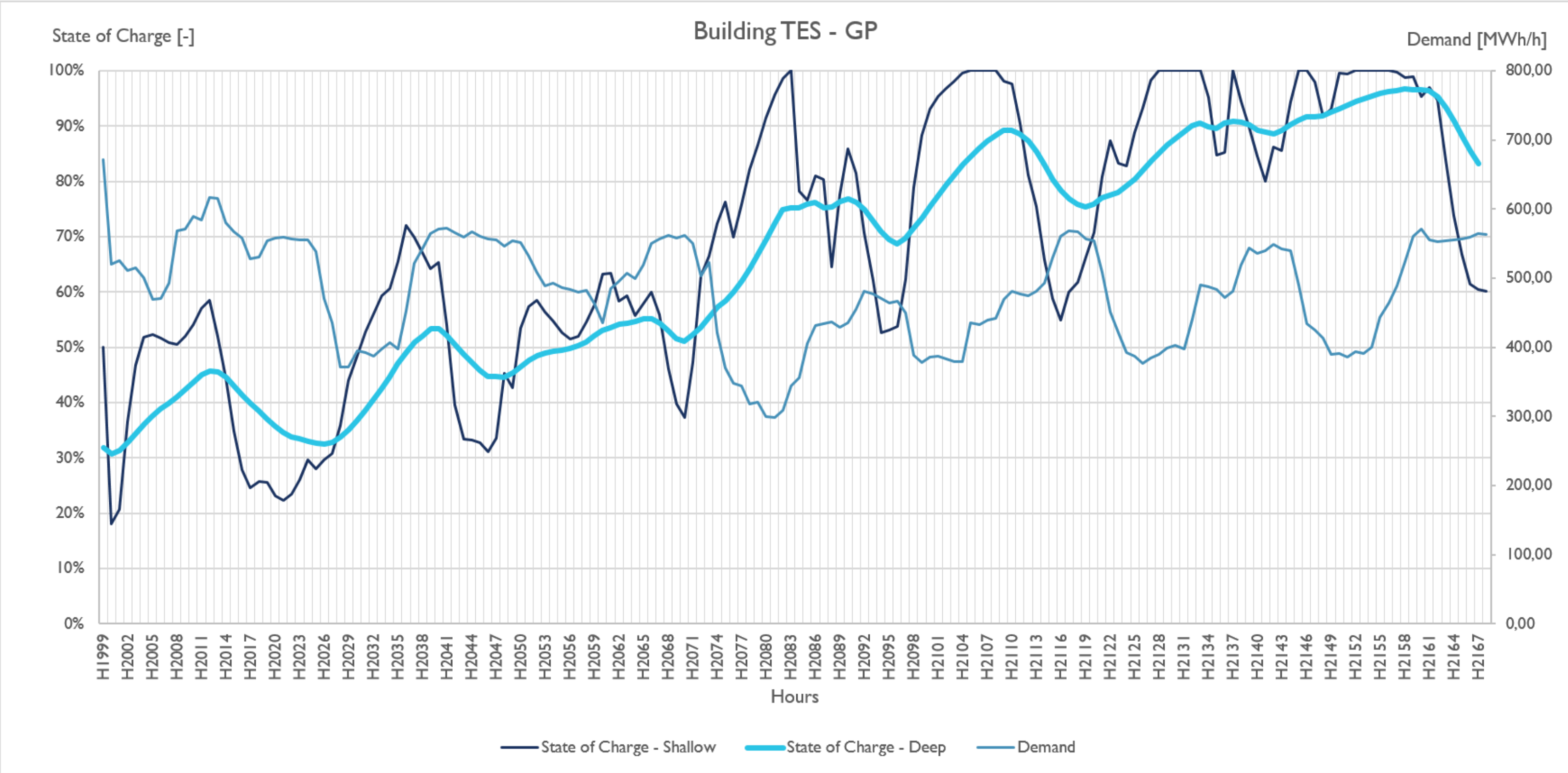


Figure 4.13: State of charge of storage in buildings and heat demand during a week in March in GP scenario

In comparison to the accumulator storage, the state of charge of the shallow storage in buildings fluctuates more, and it does not go down to zero at any time during the week. The reason that it never drops to zero is that the shallow storage gets charged from the deep storage, and the discharge rate from the shallow storage is not fast enough to completely empty the shallow storage in an hour. By comparing the charge/discharge behaviour of the shallow storage with the demand it can be seen that the storage is discharged during peaks in demand and charged in valleys. The yearly standard deviation of the state of charge of the shallow storage and the accumulator were calculated for comparison. The accumulator has a standard deviation of 0.30 while the standard deviation of the shallow storage is 0.34. This supports the conclusion that the building storage has a more fluctuating operation pattern than an accumulator. One reason that the shallow storage fluctuates more than an accumulator could be that there are no heat losses in the shallow storage. This means that there is no "cost" associated with using the building storage, one can just as well charge in one hour and use the same heat in the next consecutive hour. If a heat loss was modelled in the building storage, one could expect the state of charge in the shallow storage to fluctuate less.

4.3.4 Heat load variation

The relative daily heat load variation for the base, accumulator and building storage cases is presented in Figure 4.14. Compared to the accumulator tank, the building storage gives less reductions in daily heat load variation. The highest variation is decreased by 2 % compared to the base case and there are very few days with zero variation in heat load. This is explained by the fact that the building storage is more used as a heat sink for CHPs than as a means to reduce peak loads. The accumulator has a larger power capacity and is more effective at reducing high peak loads. The building storage reduces many peak loads by a small amount of heat, whereas the accumulator reduces fewer peak loads but with a higher amount of heat.

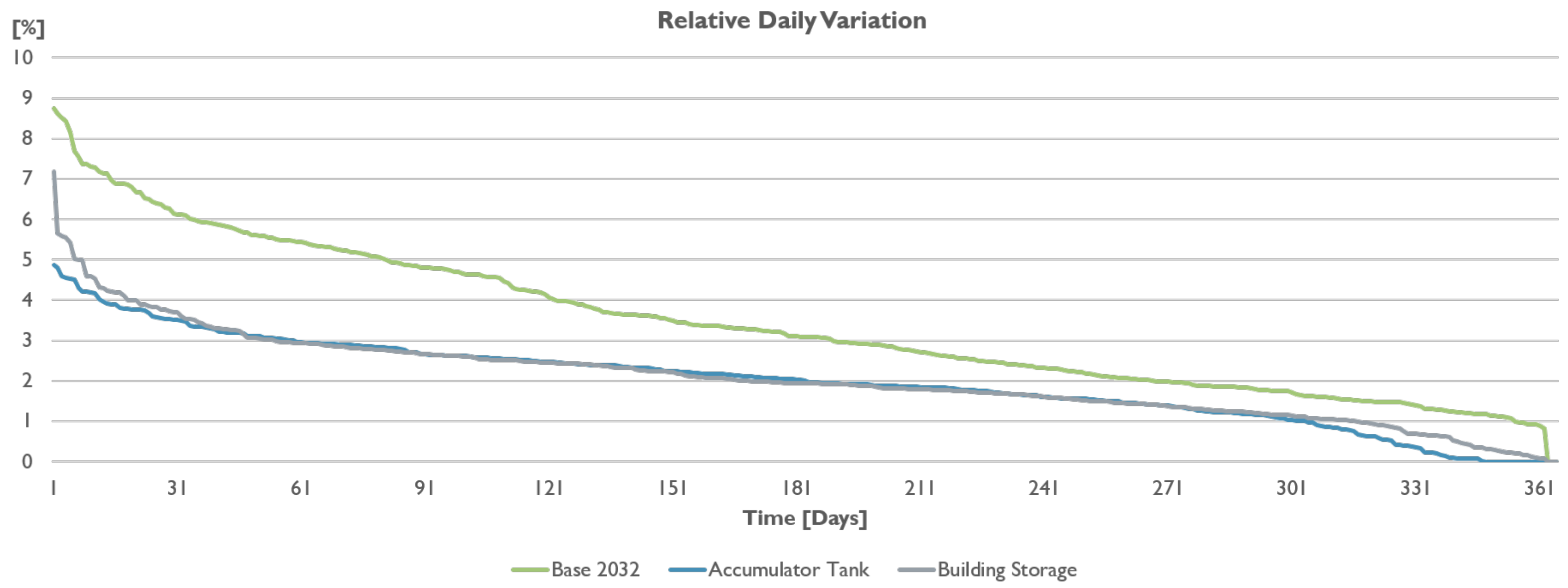


Figure 4.14: Relative daily heat load variation for base, accumulator and building storage cases

The building storage has better economic performance than the accumulator. On the other hand, the accumulator shows more benefits in terms of system operation. It should be noted that neither storage has been operated with the aim of reducing variations, but rather minimise costs in the entire system. The building storage has the advantage of not having any heat losses, which may be the cause for overestimating the benefits from a building storage.

4.4 Seasonal Thermal Energy Storage

In comparison to TES in an accumulator or in buildings, the impact of a seasonal storage in the district heating system is substantial. Figure 4.15 shows the dispatch of heat generation plants during 2032, where the base case is shown for comparison. As for the previously presented scenarios, only the GP electricity scenario is presented.

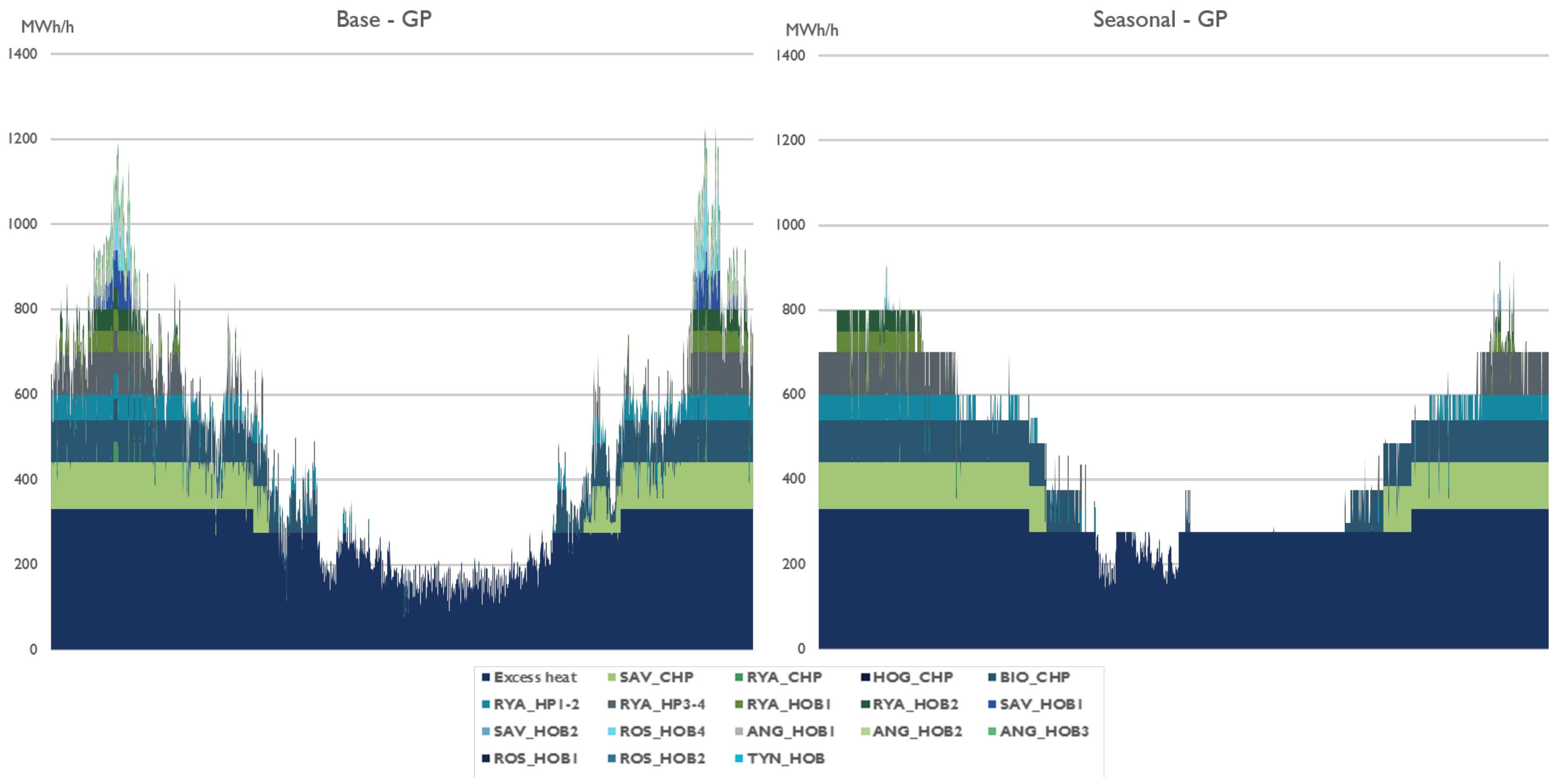


Figure 4.15: Heat generation dispatch for electricity scenario GP. Left: base case. Right: with seasonal storage

It is clear that a seasonal storage effectively reduces peak loads during winter and utilises more available excess heat in summer. The highest peaks in the year are reduced from 1270 MWh/h to 965 MWh/h. Not only are the highest peaks reduced, but also peaks during lower demand-periods. Since the seasonal storage was modelled without any restrictions as to when during the year that one could charge or discharge, the storage is also used for short term storage. This can be seen in the transition periods between summer and winter, where valleys in demand have been filled with heat from CHP plants. This heat has later been used to reduce peak loads. In principle, the seasonal storage has been used as a heat sink for CHP plants that can be used when electricity prices are high and the demand for heat is low. However, the CHPs only provide a small share of the total stored heat in the seasonal storage. The largest share is provided by excess heat that would otherwise be cooled off. Comparing the dispatch diagrams in Figure 4.15, the heat generation during summer months is vastly different when a seasonal storage is available. The excess heat is used to its full extent for the entire summer period, which in the dispatch can be seen as the large block of constant heat output. There is a short period in the beginning of summer where excess heat is cooled off, this is because the storage has not started to charge at this time. Since there are losses in the storage, it is better to start charging the storage later, rather than sooner. In the middle of the year, just after the charging of the storage has started, the bio CHP is put in to operation for a few hours. This is because the electricity prices are extremely high during these hours so that the total running costs for the CHP are actually lower than for excess heat. In practice the CHP plant would be shut down during summer and most likely not be started just to run for a few hours.

4.4.1 Total system costs

The cost savings from a seasonal storage are of course substantial, since the peak load reductions are so large. By acting as a heat sink for CHP plants, even larger cost savings are achieved because of the additional sold electricity. Table 4.9 shows the total system costs savings compared to the reference base case in all electricity scenarios.

Table 4.9: Total system cost difference compared to base case, with seasonal TES

Scenario	Cost difference [MSEK/yr]
GP	-142.00 (-32.4%)
RP	-138.79 (-29.9%)
CM	-141.34 (-32.4%)

The cost savings that are achieved in all electricity scenarios are in between 138 and 142 MSEK per year. The RP scenario gives lower relative cost savings since electricity prices are lower. The estimated minimum investment cost for this seasonal storage is 600 MSEK, which would indicate that a simple payback period would be roughly 4.5 years. However, this figure should be seen as highly uncertain, since only the excavation costs are included in the investment costs. Also, this investment cost does not take into account the heat needed in order for the entire storage volume to reach operational temperature levels, which may take several years. Still, if one assumes that the investment cost would double, the payback period would be under 10 years. These payback periods indicates that even with the very high investment cost that a seasonal storage would bring with it, it could still be a good investment to make.

4.4.2 Heat generation

When a seasonal storage is added to the DH system, the generation of heat from multiple plants is substantially reduced. Most of the HOBs in the system are never put into operation. Instead, the use of excess heat is increased and is utilised via the seasonal storage. The use of excess heat in the seasonal storage case is presented together with the corresponding use in the base case in Table 4.10.

Table 4.10: Total use of excess heat in base case and with seasonal storage

	Total excess heat used [GWh]	
Scenario	Base	With seasonal storage
GP	2372	2586
RP	2379	2590
CM	2376	2590

Roughly, the use of excess heat increases by 210 GWh when a seasonal storage is added to the system. The heat generation from all plant types in the GP electricity scenario is presented in Figure 4.16. Also shown in Figure 4.16 is the heat generation in the base case. The total amount of generated heat when a seasonal storage is available is roughly 4.6 TWh in all electricity scenarios. This is an increase of 0.3 TWh, which corresponds to the increased use of excess heat during summer months.

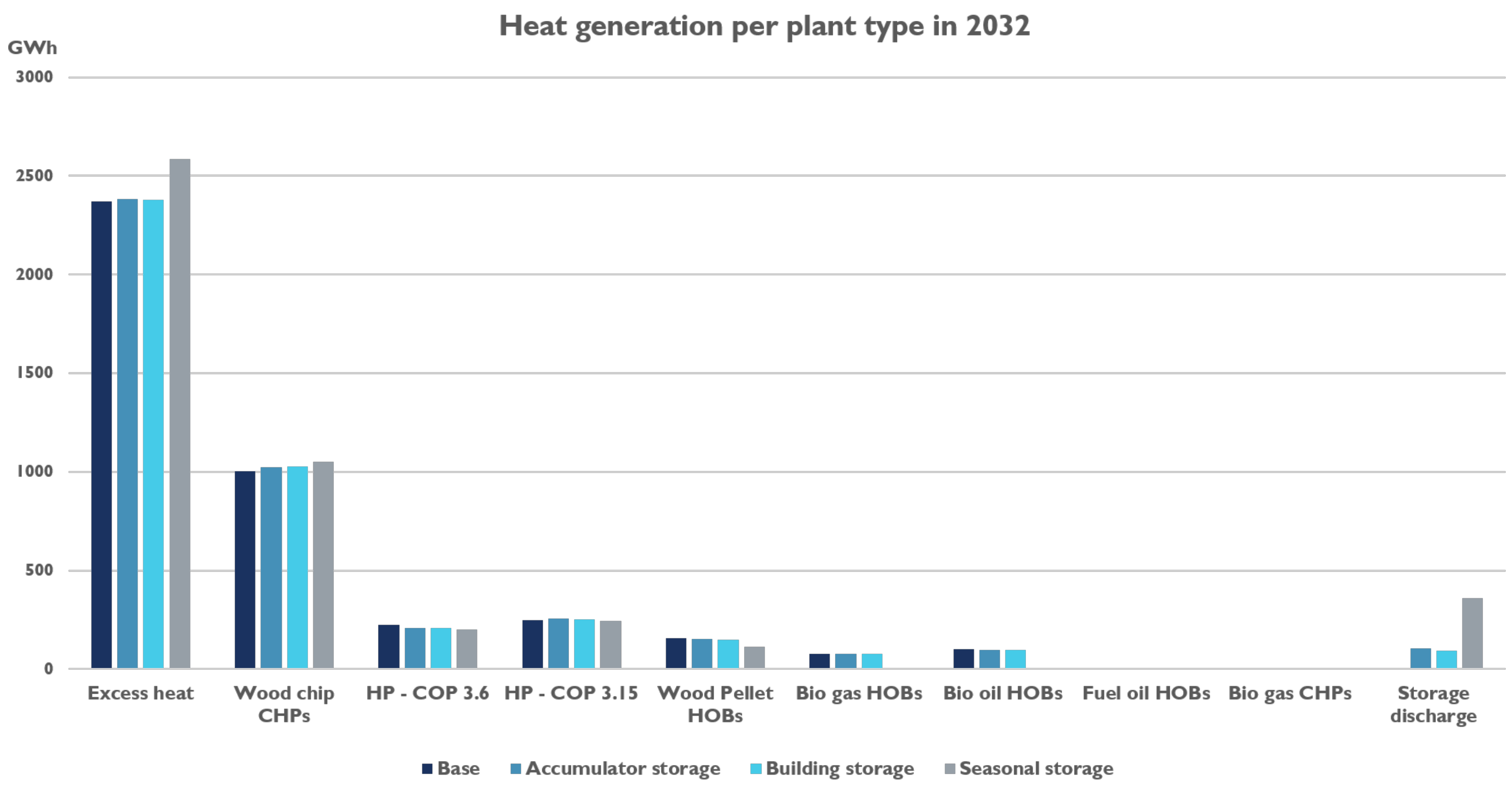


Figure 4.16: Total heat generation per plant type in 2032 for base, accumulator, building and seasonal storage cases. The data is shown for the GP electricity scenario only.

From Figure 4.16, it is clear that the use of HOBs is more or less avoided when a seasonal storage exists. The exceptions are HOB 1 and 2 at Rya, which are fuelled by wood pellets. Rya CHP is not used at all during the year in this case, regardless of electricity scenario. In fact, no bio gas is used at all for the generation of heat in the entire system. The seasonal storage makes it possible to avoid the use of bio gas and fossil fuel by enabling the increased use of excess heat during the year.

4.4.3 Storage

The amount of heat that has been discharged form the seasonal storage in all electricity scenarios is presented in Table 4.11.

Table 4.11: Total discharged heat from the seasonal storage during a year

Scenario	Discharged heat [GWh]
GP	357.4
RP	357.4
CM	357.4

The amount of heat that is being discharged from the seasonal storage is unaffected by the electricity scenarios. This is because the storage is charged with waste heat, which are not affected by electricity prices. Thus the cost of discharging the heat later in the year is roughly the same as using waste heat. This puts the seasonal storage early in the merit order and it is always used before plants that are affected by electricity prices.

By dividing the discharged heat with the storage capacity of 200 GWh, one finds that the storage is fully charged and discharged 1.8 times in a year. This can also be seen when examining the state of charge during the year, which can be seen in Figure 4.17 below. Here, the state of charge of the seasonal storage is plotted together with the hourly heat demand of a year in the GP electricity scenario.

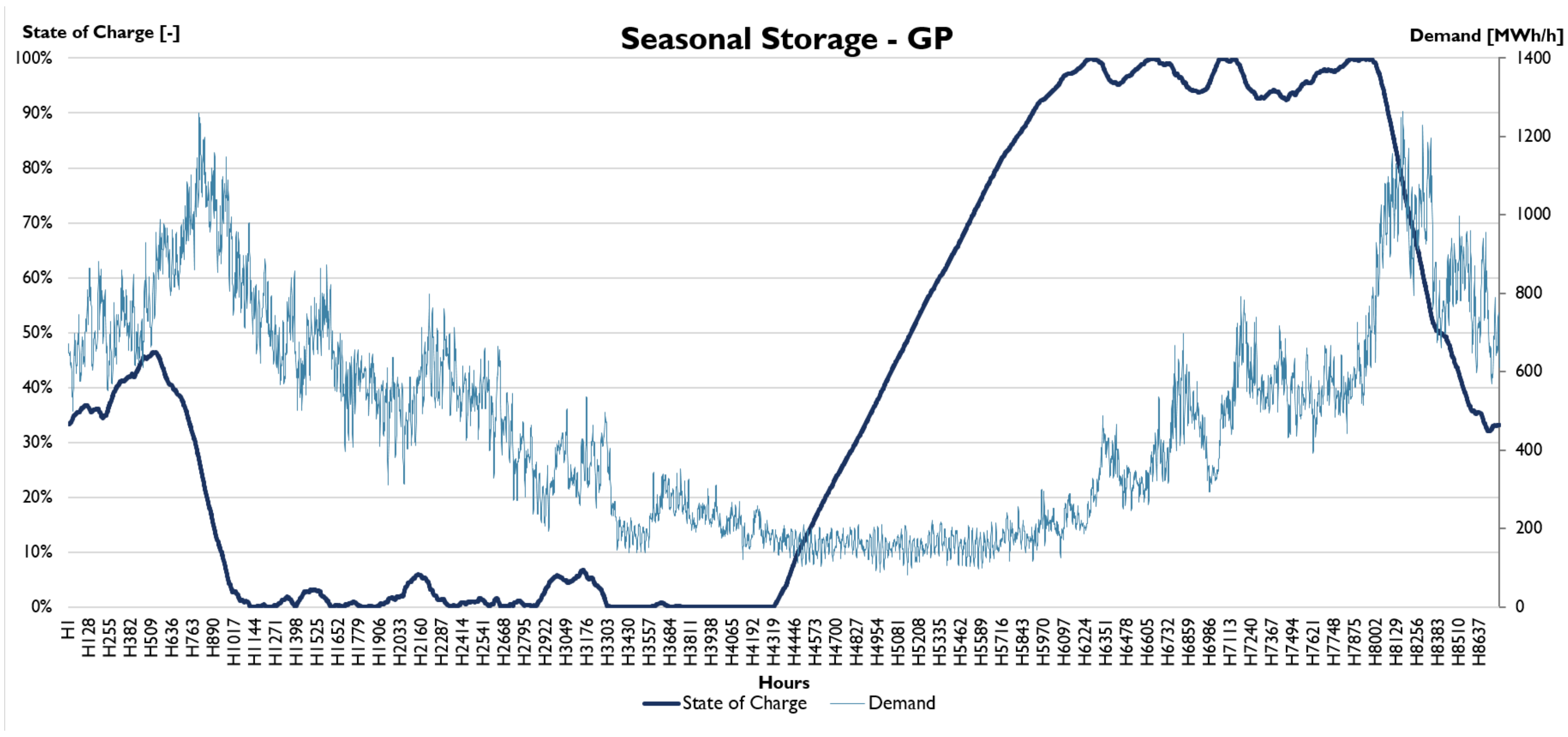


Figure 4.17: State of charge of seasonal storage and demand in 2032 in GP scenario

The seasonal storage is charged with heat during the part of the year when the demand is at its lowest, i.e. during summer. This of course coincides with the lowest marginal cost for generating heat. The storage is empty by the beginning of the spring period and starts charging hour 4300, which is in the end of June. This is partly because the optimisation was performed with hour 3300 as starting point, as described in Section 3.3.3.

The storage is kept more or less fully charged throughout the fall, it used to cover some smaller peaks and then recharged again. The largest discharge of the seasonal storage occurs between hours 8000 and 8760, which is the entire month of December. During these hours, more than half of the energy in the storage is discharged.

The remaining energy is saved for the second largest peak in demand, which occurs around hour 700 where the storage is fully emptied. During the following winter/spring period, the storage is used more like a short term storage would be used.

4.4.4 Heat load variation

The seasonal storage makes it possible to increase the use of excess heat during summer, so that the total heat load during the summer months is constant at the rated maximum output of the excess heat. During winter, peak loads are heavily reduced. These two effects leads to a significant reduction in both daily and seasonal heat load variation. The relative daily heat load variation during the year 2032 for all studied cases so far is plotted in Figure 4.18.

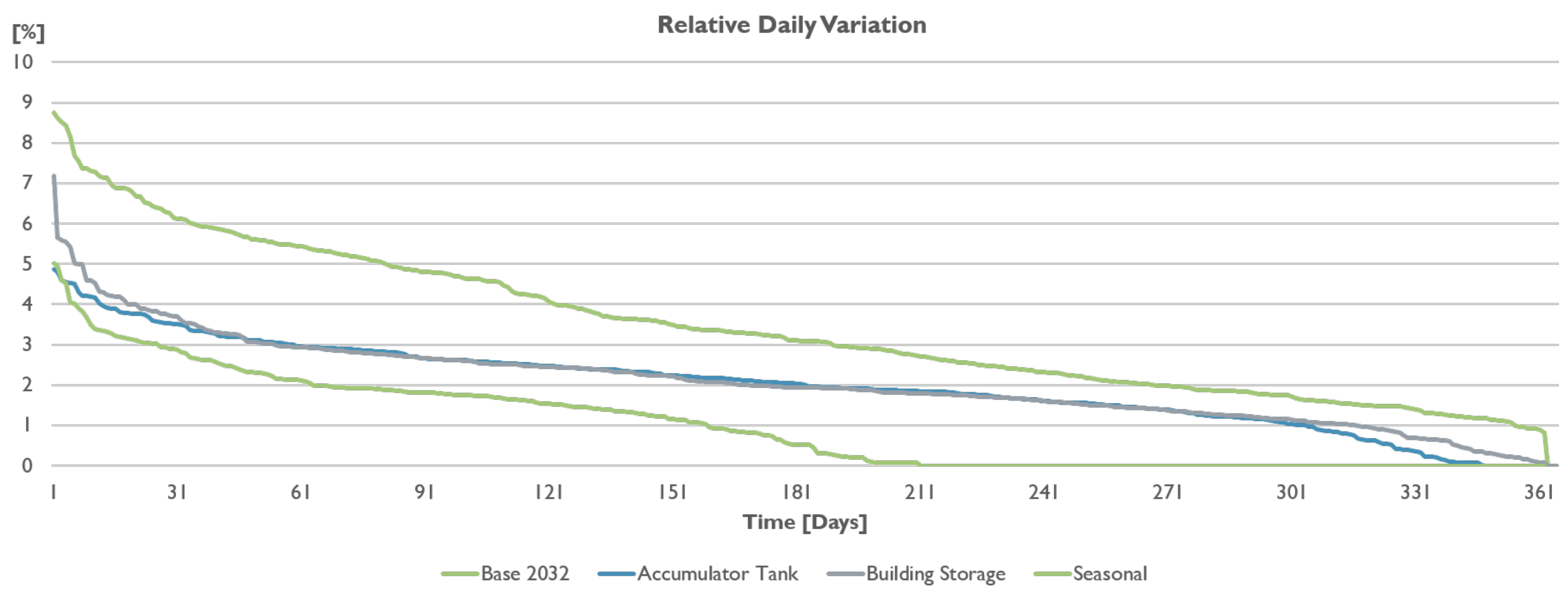


Figure 4.18: Relative daily heat load variation in 2032 for base, accumulator, building and seasonal storage cases.

For more than 100 days, the relative daily heat load variation is zero when there is a seasonal storage available. These days occur during summer when the storage is charged with excess heat, and during days when the discharged heat from the storage makes it possible to use all excess heat at a constant level for the entire day. The maximum relative variation with a seasonal storage is somewhat higher than with an accumulator. This is most likely the result of the seasonal storage not being used during the beginning of the summer period, where the accumulator is actually used to reduce peaks and/or fill valleys of heat demand. Since peak loads are reduced during winter and the load is increased during summer, the yearly load profile approaches the yearly average load. This is verified by calculating the annual relative seasonal heat load variation, which is 13.77 % when a seasonal storage is available. The annual seasonal variation can thus be reduced by 10 percentage points compared to the base case, which has a annual seasonal variation in heat load of 23.8%. In addition to giving large yearly savings based on running costs of the heat generation plants, one could also expect cost savings in the form of a reduced need for maintenance since plants can be operated more smoothly.

4.5 Exhaust air heat pumps

The results obtained from the modeling of exhaust air heat pumps in the future district heating system contains; total system running cost, heat generation and the EAHPs effect on the hourly operation of the district heating system. Followed by this is a comparison between the results obtained from the prioritized scenarios and the scenarios, which utilize heat source shifting control. See section 2.6.1.1 for detailed information regarding the different control schemes.

For the sake of readability, the results from the two different control schemes are presented separately. The results from running the optimisation models with exhaust air heat pumps under prioritized control scheme is first presented. The reason for showing results from prioritized control strategy first is motivated by this being the traditional way of running the heat pumps and implementation of new heat pumps today and at least the near future would primarily have this control. In addition to model two different control schemes also five different deployment levels, 10,20,30,50 and 100 %, of EAHPs in the new and refurbished apartment buildings were modeled. The five deployment levels will be referred to as a % of apartments with EAHP installed, in short % of apt.

The resulting dispatch of the heat generation for the base case and a scenario where 100% of the refurbished and new buildings in Gothenburg are equipped with EAHPs are presented below in figure 4.19. The electricity scenario presented is the GP-case.

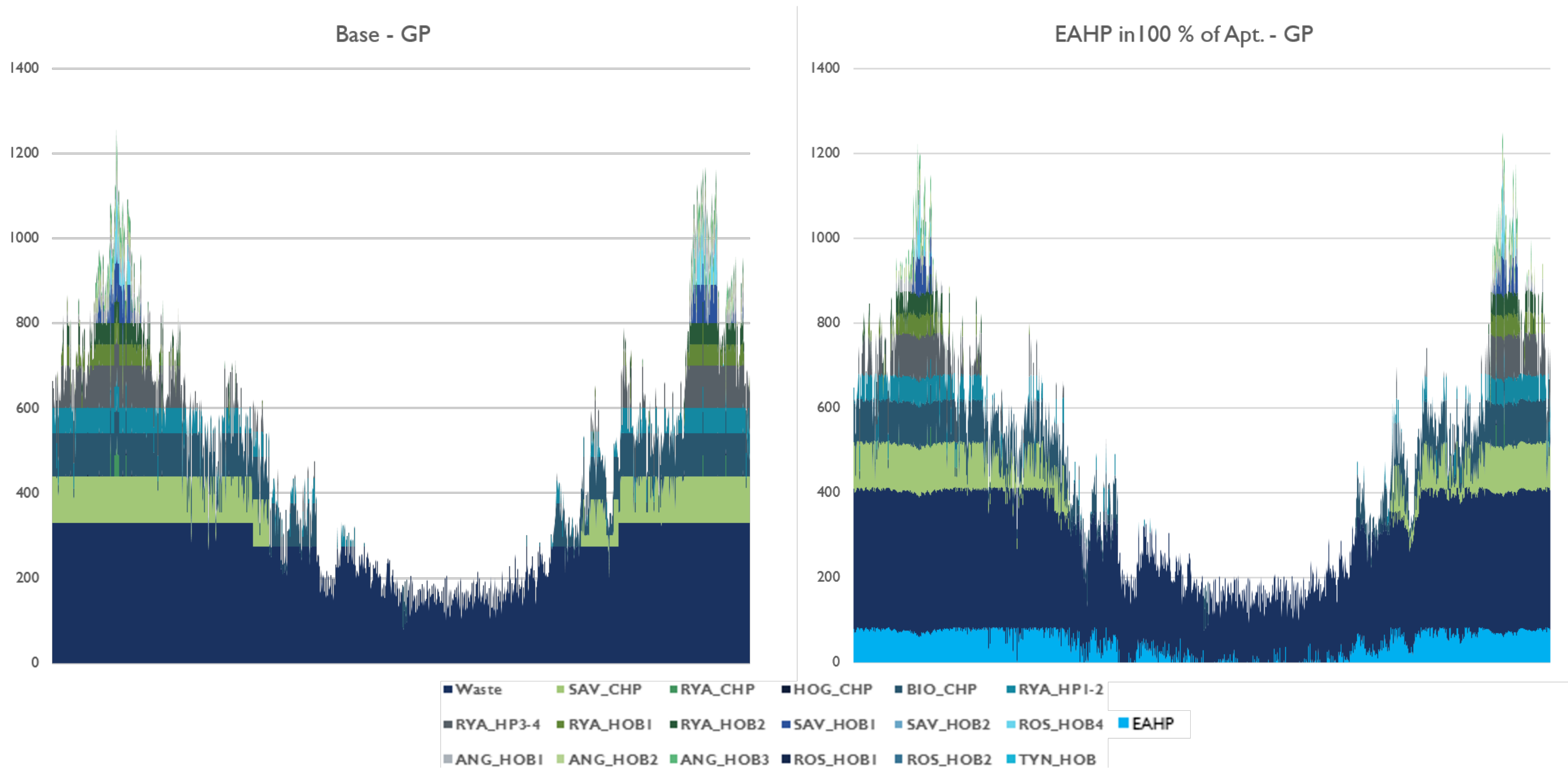


Figure 4.19: Heat generation dispatch for electricity scenario GP. Left: base case. Right: with EAHPs in 100 % of new and refurbished buildings.

The choice of using the 100% deployment scenario is made because of easier visualization of the impact that the EAHPs can have on the operation of heat generation plants. From the figure it can be seen that the EAHPs supply space heating as soon as there is a heat demand and during warm hours they completely turned off.

This is expected since the prioritized control scheme is used and the EAHPs is run regardless of it being the most cost optimal option for the heat generation system.

A 100% deployment is a strictly theoretical scenario and the magnitude of the EAHPs impact should not be too deeply analyzed. Instead a scenario with a deployment level of 30% is more thoroughly investigate in following sections, 30% is a high level of deployment compared to historical values but it is still a plausible development.

4.5.1 Total system running costs

The modeling is carried out in such a manner that the running cost of the EAHPs are included in the minimized objective function of the whole heating system. A decrease in system cost then means, from a strictly economical point of view, that the supply of space heating through the use of EAHPs would benefit the total system of meeting the heat demand in Gothenburg. For prioritized control the total system cost difference for the three different electricity scenarios and the five levels of deployment are displayed below in table 4.12.

Table 4.12: Total system cost difference compared to base case, with prioritized control of EAHPs.

	Cost saving [MSEK/year]		
% of apt.	GP	RP	CM
100	-54.1 (-12.3%)	-71.4 (-15.4%)	-53.2 (-12.2%)
50	-30.3 (-6.9%)	-38.2 (-8.2%)	-30.0 (-6.8%)
30	-18.9 (-4.3%)	-23.6 (-5.1%)	-18.8 (-4.3%)
20	-12.9 (-2.9%)	-16.0 (-3.4%)	-12.8 (-2.9%)
10	-6.6 (-1.5%)	-8.2 (-1.8%)	-6.5 (-1.5%)

By deploying EAHPs in the system, heat can be supplied with lower total running cost. In table 4.12 the RP electricity case, which have the lowest average electricity cost, is the most profitable for EAHPs. A EAHPs consumes electricity in order to generate heat and lower electricity prices naturally favors the run time of a EAHP. The cost reduction for the GP and CM case is very similar and the total system costs are on average 16.0 and 16.3 % more expensive compared to RP. An interesting observation is that the savings arising from the deployment of heat pumps are not completely linear with respect to increasing deployment levels. The introduction of EAHPs affect the marginal cost of heat for some hours of the year since they are utilized before other intermediate and peak heat generating units. The heat generating plants on the margin will be taken offline as new heat generating capacity is introduced through the EAHPs. The marginal cost of heat is then decreased and with a larger implementation of EAHPs more hours have their marginal cost of heat decreased resulting in less savings for additional EAHP deployment.

4.5.1.1 Investment costs and system benefit

The reduction in running costs stems from EAHPs supplying heat, through the use of exhaust air and electricity that would otherwise be supplied by a more expensive production unit. From this it is evident that a utility company could stand to lose heat deliveries and revenue when exhaust air heat pumps are deployed as an additional source of heating. In order to evaluate if EAHPs are a wise investment for the heating system as a whole one need to look at the costs associated with acquiring a heat pump since investments have to be made by buildings owners or utilities in order to access these lower running costs.

For calculating the investment and installation cost the exhaust air heat pump MEGA XL manufactured by Danfoss Värmepumpar AB was used. This heat pump has a power capacity of 88 kW which is very large and the investment and installation cost is approximated as 300 000 SEK (E. Olsson 2016). The cost of one EAHP was scaled with the required amount of installed EAHPs in each scenario yielding the total investment cost. By comparing the investment cost with the system savings for each scenario one reaches a payback period for the investment of the EAHP. The payback period at a 10, 20 and 30% deployment level is presented in table 4.13 for the three electricity scenarios.

Table 4.13: Payback period for EAHPs at the lower deployment levels.

	Payback period [years]		
% of apt.	GP	RP	CM
30	4.5	3.6	4.5
20	4.4	3.5	4.4
10	4.3	3.4	4.3

A payback period between 3.4 and 4.5 years, depending on the electricity and deployment level scenario, is found for the EAHPs. The payback periods for the GP and CM case is about the same which corresponds to their savings being almost equal as well. The shortest payback period of 3.4 years arises for the RP-scenario with 10% deployment level. This is directly linked to the results above regarding the cost differences, the investment cost of EAHPs increases linearly with deployment levels while the increase in savings are slowly diminishing. However, all of the payback periods are relatively short in contrast to economical life times of a heat pump which would suggest that investing in a EAHPs favors the heating system from an economical point of view.

The payback calculation performed above includes both installation and heat pump investment costs, one should note here that installation cost for a EAHP can vary significantly depending on specific building conditions. Further, the size of the chosen heat pump to base the calculations on is quite large, 88 kW, a smaller heat pump would result in a higher cost due to more installations being required to cover the need. The payback time for more smaller heat pumps would have to be paid back with the same savings and thus an increase in payback time would be expected.

4.5.2 Heat generation

The total heat generation are to different degrees affected by an introduction of EAHPs in new and refurbished buildings. The general trend for all five scenarios with different levels of EAHP deployment is that some heat generated by CHPs, HPs and HOBs decreases and is replaced by space heating generation in buildings that have a EAHP. In figure 4.20 the heat generation per plant type during the GP electricity scenario can be seen for the base case and the EAHP scenarios with 30 and 100 % deployment level.

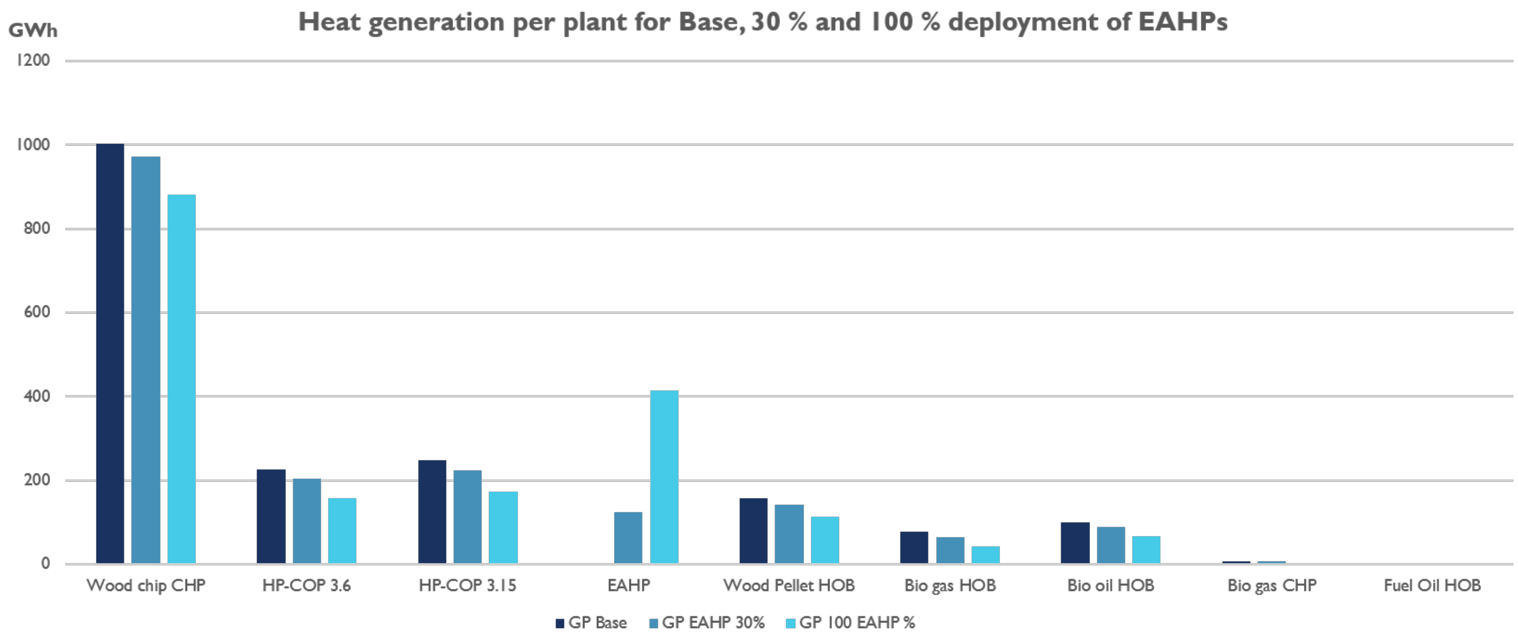


Figure 4.20: Heat generation per plant type

The chart above gives an indication of how much heat demand that the utility company in Gothenburg potentially can loose to the EAHPs. The maximum theoretical heat load loss is seen when looking at the 100 % EAHP deployment bar, about 400 GWh could be lost in heat load due to EAHPs. For the more reasonable scenario with 30 % deployment of EAHPs the lost heat load amounts to 124 GWh, about 2.96% of the total yearly load. The reduction in heat generated from bio gas, bio oil and wood chips reveals that the heat generation is less dependent on bio fuels with an introduction of EAHPs in the system.

In prioritized scenarios the EAHPs are always operated when there is a demand for space heat. The changes to total heat generation is therefore not only a result from plants running costs since the heat pumps will be run even though they are not the most cost optimal solution. The EAHPs used in these scenarios have a high COP, which makes them cost efficient in the majority of hours during the year. From this follows that the cost penalty for running the EAHPs in hours where the electricity price is high and/or the demand is low does not offset the overall cost benefit from having them as an heat generation alternative for the other hours of the year. In figure 4.21 the hourly heat generation from the EAHP and the heat demand can be seen together with a horizontal bar representing the maximum available generation capacity from excess heat. The figure illustrates the operative behaviour of the EAHPs and it can be clearly seen that they are operated during periods where the excess heat is not yet fully utilized.

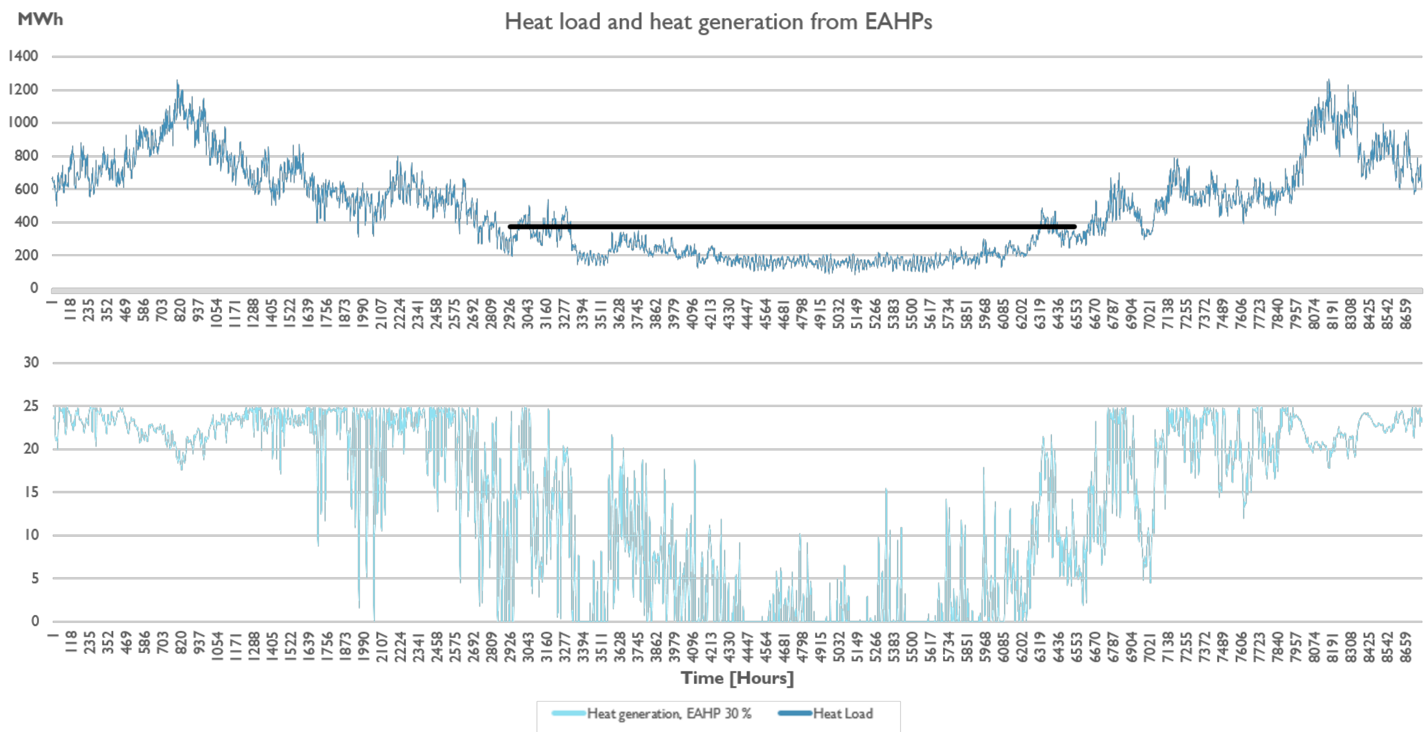


Figure 4.21: Hourly heat load with horizontal line indicating available excess heat and heat generation from EAHPs at 30% deployment level.

It is clear from 4.19 that their are opportunities to optimise the generation from EAHPs during hours where they are not cost optimal, the results from this would be an additional cost reduction for supplying heat to the system. The effect of operating the EAHPs after the running cost is investigated in section 4.5.5 where the decision to operate a EAHP is based on the cost of heat and electricity in every hour.

4.5.3 Heat load variations

When combining a EAHP with an already existing district heating connection the base load is traditionally covered by the new EAHP and the intermediate and peak loads are supplied by district heating. Moving towards being a intermediate and peak load supplier could increase the daily heat load variations. This is contrary to what a utility company wants and the advantages of having low daily heat load variations can be reviewed in 2.3.1. The effect on the daily heat load variations is presented below in figure 4.22. The figure contains the relative daily variation for the base case and the EAHP scenarios with 30 and 100 % deployment levels.

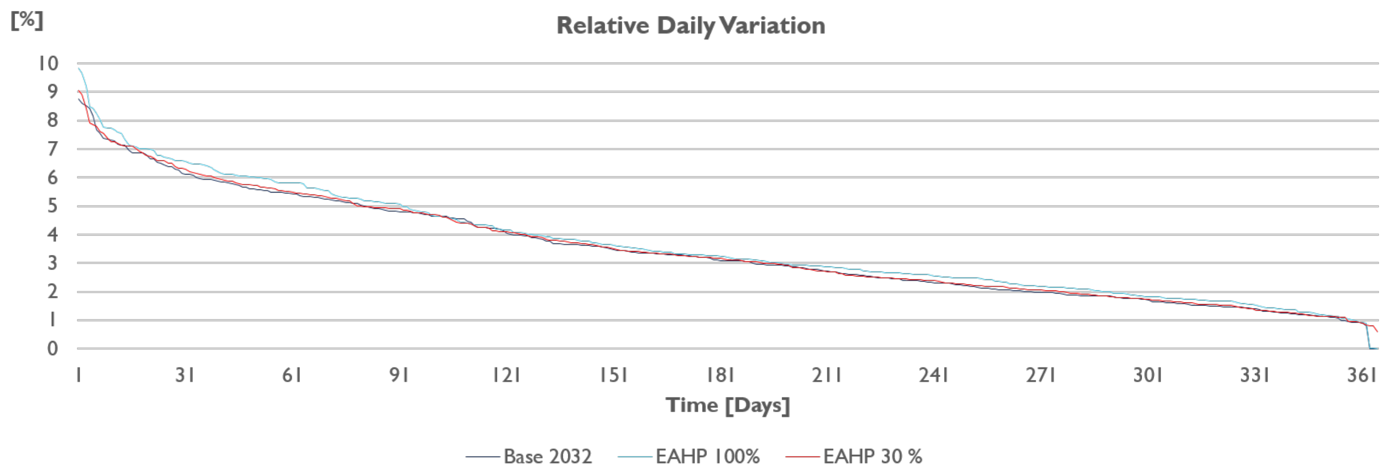


Figure 4.22: Relative daily heat load variations for base case 2032 and two scenarios with 30 % and 100 % deployment of EAHPs.

The relative daily variations experienced by the utility were calculated by subtracting the EAHPs heat generation from the total heat demand. The relative daily variations generally increases as the amount of heat pumps introduced into the system increases. The trend towards higher daily heat load variations are not good but the increased amount of daily variations are still small even at the theoretical scenario of 100% deployment level of EAHPs. The results here does not take in to account the deployment density of EAHPs in the region of Gothenburg and local heat load variations in the system due to EAHPs are not covered.

The annual relative seasonal variations for the base case and the EAHP scenarios with deployment levels 30 and 100 % are presented in table 4.14.

Table 4.14: Annual relative seasonal variations for base case and EAHP scenarios with 30 and % deployment levels.

Scenario	Annual relative seasonal variation
2032	23.90
EAHP 30%	23.75
EAHP 100%	23.39

The seasonal variations for the district heating supplier decreases as EAHPs are deployed throughout the system. The EAHPs replaces generation capacity that during the winter, spring and autumn helps reduce the average seasonal loads. During the summer the heat pumps are still operated but the amount of heat load due to space heat is much less and the average heat load during the summer is not as much affected as the rest of the seasons. This brings the seasons average loads closer to each other and thus effectively reduces the annual seasonal relative variation.

4.5.4 Effect of enabling heat source shifting

The EAHPs were also modeled with a smarter control scheme that decides if the EAHPs should be used based on actual running cost for each hour. A building equipped with a EAHP and a district heating connection could then utilize the most cost effective source of heating. In order for this to be possible either a EAHP owner would need access to hourly electricity and heat prices or a utility could invest and control the operation of the heat pumps. With heat source shifting the EAHPs operation is changed and the hourly heat generation is now decided according to the merit order. The EAHP heat generation when using heat source shifting can be seen in figure 4.23. The electricity scenario used is the GP case.

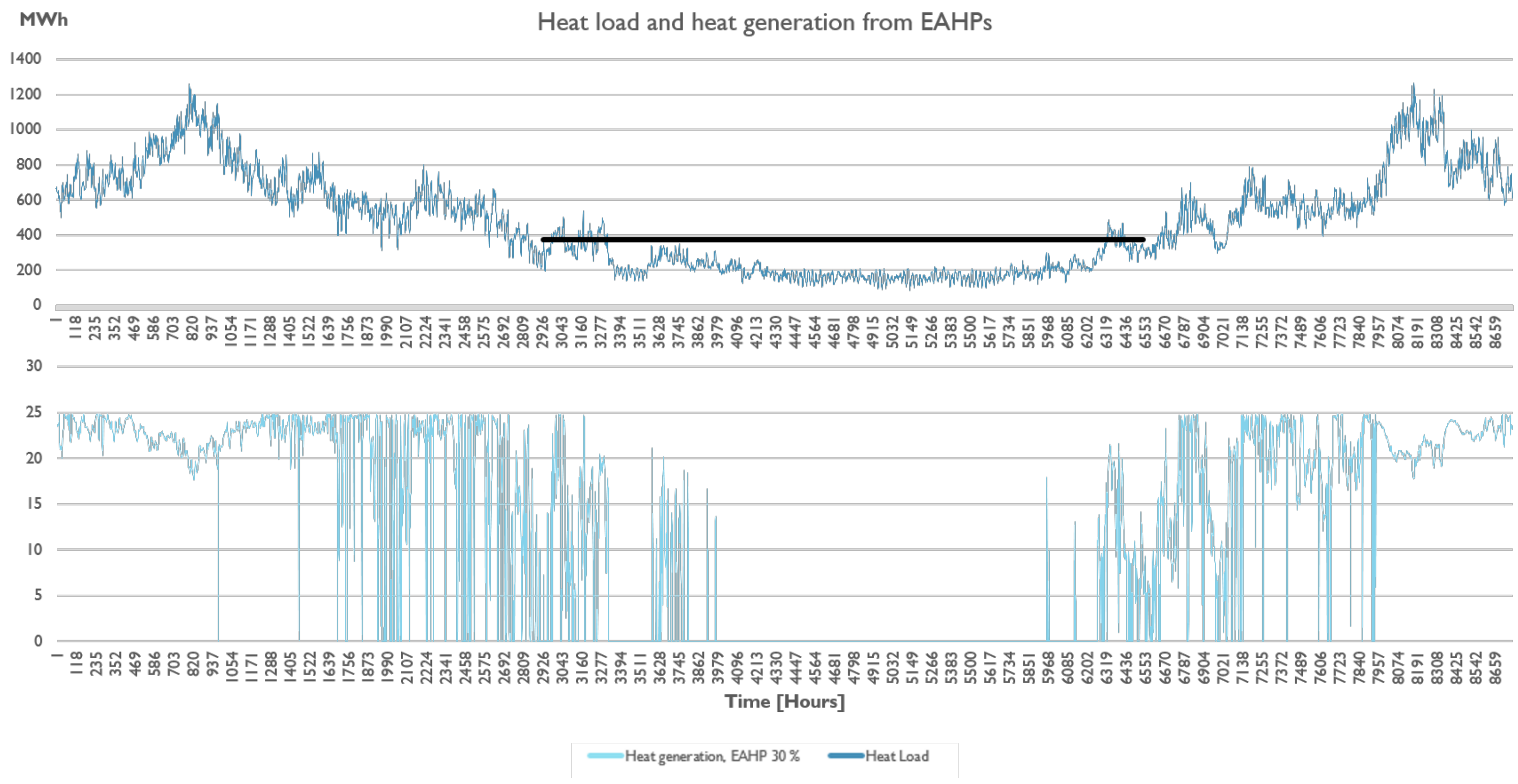


Figure 4.23: Hourly heat load with horizontal bar indicating available excess heat and heat generation from EAHPs at 30% deployment level.

By comparing figure 4.21 and 4.23 it can be clearly seen that the EAHPs have been turned of effectively during the summer when the demand for heat is low and excess heat is available for space heating. It can also be seen that the EAHP has been turned off for a number of other hours, primarily during spring and fall. The hours were the EAHPs are turned off corresponds to either high electricity prices and/or low heat demand.

The total system running cost for both control schemes were calculated and compared, the cost reduction achieved when enabling heat source shifting control compared to prioritized control can be seen below in table 4.15.

Table 4.15: Comparison of total system running cost between heat source shifting and prioritized control scenarios.

	Cost saving [MSEK/year]		
% EAHP in apts.	GP	RP	CM
100	-5.0(-1.31%)	-2.2(-0.57%)	-5.7(-1.48%)
50	-2.1(-0.52%)	-1.0(-0.24%)	-2.4(-0.59%)
30	-1.2(-0.29%)	-0.6(-0.14%)	-1.4(-0.33%)
20	-0.8(-0.19%)	-0.4(-0.09%)	-0.9(-0.21%)
10	-0.4(-0.09%)	-0.2(-0.04%)	-0.4(-0.10%)

The cost reduction when utilizing heat source shifting shows that the system running cost of the district heating system decreases. By comparing the savings from EAHPs using traditional control, see table 4.12, and EAHPs using heat source shifting control the increase in savings can be calculated. The additional savings when running the EAHPs with heat source shifting control are for these cases 5%. The savings increases as the amount of deployed EAHP increase but so does also the additional investment cost for a utility or EAHP owner. In order to evaluate if these measures should be implemented one have to look at the actual investment that is required to allow for this kind of control strategy.

4.6 Combinations of scenarios

Two combinations of scenarios were studied in the GP electricity price scenario. The results from this are presented in the two following sections.

4.6.1 Buildings as TES and exhaust air heat pumps

Exhaust air heat pumps were added to the scenario where buildings are used as TES. The amount of heat pumps added correspond to the 30% case described in Section 4.5. The added exhaust air heat pumps have the ability shift heat source. By adding exhaust air heat pumps, neither the operation of the buildings used as TES nor the exhaust air heat pumps are changed from their individual cases. The amount of discharged heat from the shallow storage in buildings is increased by 345 MWh or 0.3% and the total heat generated by exhaust air heat pumps is decreased by 242 MWh or 0.2%. The total system costs are decreased by 29.4 MSEK or 6.7 % per year, which is close to the sum of the savings achieved from the two scenarios individually. Table 4.16 shows the achieved cost savings from the individual measures compared to the base case together with the cost saving from the combination of the two. In fact the sum of the cost savings in the individual cases is 28.7 MSEK/year so by implementing both technologies, additional savings can be achieved. This can be explained by the fact that exhaust air heat pumps in the system increases the daily heat load variations so that a thermal energy storage is even more beneficial.

Table 4.16: Cost savings from buildings used as TES, EAHP:s and the combination of the two compared to the base case.

Scenario	Cost saving [MSEK/year]
Buildings as TES	-9.8 (-2.2%)
EAHP (30%)	-18.9 (-4.3%)
Building + EAHP	-29.4 (-6.7%)

From this, it can be concluded that EAHPs and using buildings as TES have little effect on each other on a yearly basis. However, on an hourly basis, the operation of the building storage and the EAHPs differs. During the spring and fall periods, when EAHPs often are the heat generation that is on the margin, they will be operated differently, as they may be used to charge the storage. Therefore, the EAHPs are used in hours where they are not used without storage. The difference in heat generation achieved from the two generation types comes from a period during spring where the storage is charged almost fully and later discharged, replacing EAHPs. The lost cost savings are likely stemming from the fact that EAHPs have replaced some generation of heat from CHPs, resulting in lost income from electricity sales.

4.6.2 Buildings as TES, distributed heat pumps and accumulator tank

When combining buildings used as TES, EAHPs and an accumulator tank, the combined cost savings achieved are smaller than the sum of all individual cost savings. This is shown in more detail in Table 4.17. The more measures that are implemented, the harder it gets to achieve savings, if the measures compete with each other. The system that is being optimised is already optimised to some extent and the measures compete with each other.

Table 4.17: Cost savings from buildings used as TES, EAHP:s, accumulator and the combination of the three compared to the base case.

Scenario	Cost saving [MSEK/year]
Buildings as TES	-9.75 (-2.2%)
EAHP (30%)	-18.90 (-4.3%)
Accumulator	-8.84 (-2.0%)
Building + EAHP + Accumulator	-34.54 (-7.9%)

The sum of the cost savings from the individual measures is -39.09 MSEK/year, so 4.5 MSEK are lost when all three measures are implemented. The total heat generated by EAHPs is the same as in its individual case, while the discharged heat from both the buildings and the accumulator have decreased. The shallow storage in buildings have discharged 18.4 GWh or 19.6% of heat less than in its individual case and the heat discharged from the accumulator has decreased by 20.7 GWh or 19.6%. This could be explained by the fact that the two types of storages have slightly different operational characteristics. The building storage works over longer time periods since it has no losses and the accumulator has a larger power capacity and shorter time horizon. In their individual cases, they are to some extent used as both types of storages, since there is no better option available. When both types of storages indeed are available, one can store the heat more efficiently by selecting the correct type of storage in more situations. Therefore, one can store less heat and still get roughly the same cost savings.

The total heat generation by heat plant type in the combination case is shown together with the heat generation in the base case in Figure 4.24.

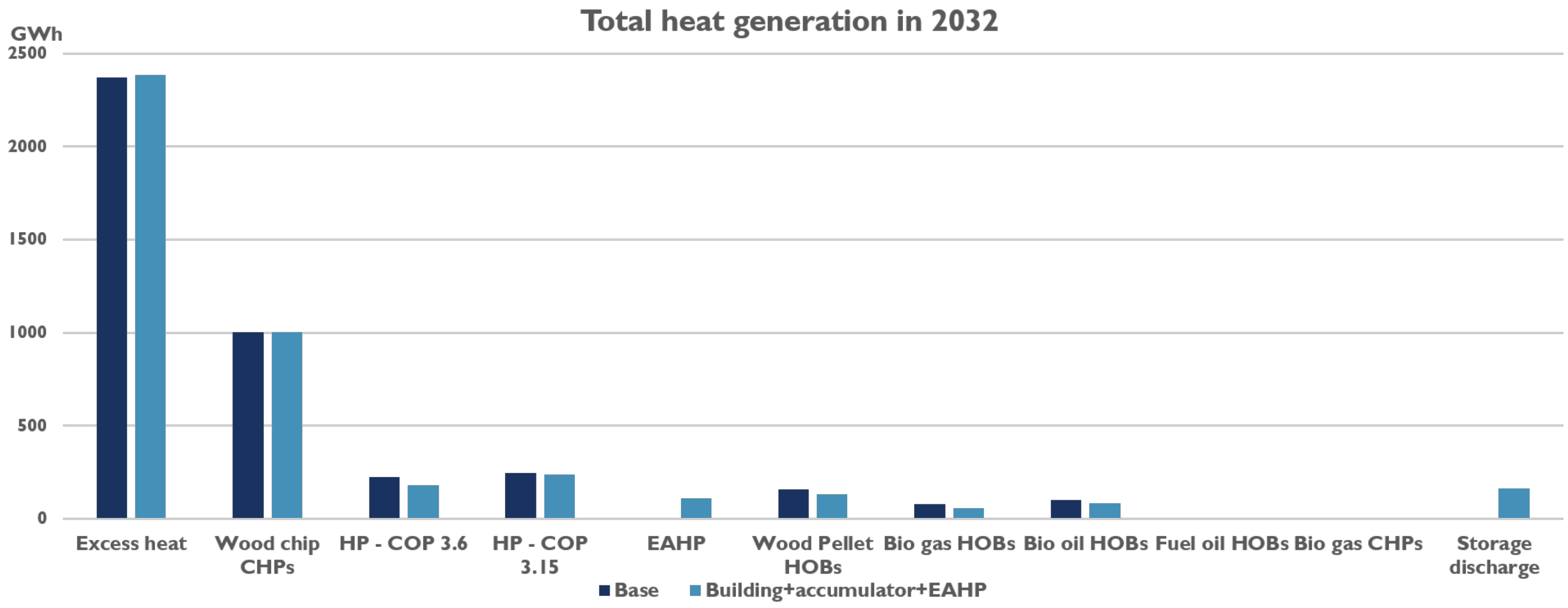


Figure 4.24: Total heat generation in 2032 if buildings are used as TES, there is an accumulator tank and 30 % of all new and refurbished buildings install an exhaust air heat pump. The heat generation in the base case is also shown. All results are from the GP electricity scenario.

The resulting total heat generation in this combination case is quite expected. The generation of heat in central, large heat pumps is decreased and the heat generation is instead taking place in the exhaust air heat pumps that have better performance. The heat generation in all HOBs is decreased substantially and is replaced by discharged heat from the two storages and by EAHPs. The fuel mix is entirely free of fossil fuels in this scenario.

When adding the two storages to the system, one does not achieve all of the individual benefits regarding heat load variation as one gets when implementing the storage one at a time. Figure 4.25 shows the relative daily heat load variation for the combination of building TES, accumulator tank and 30 % EAHP together with the base case and the individual cases.

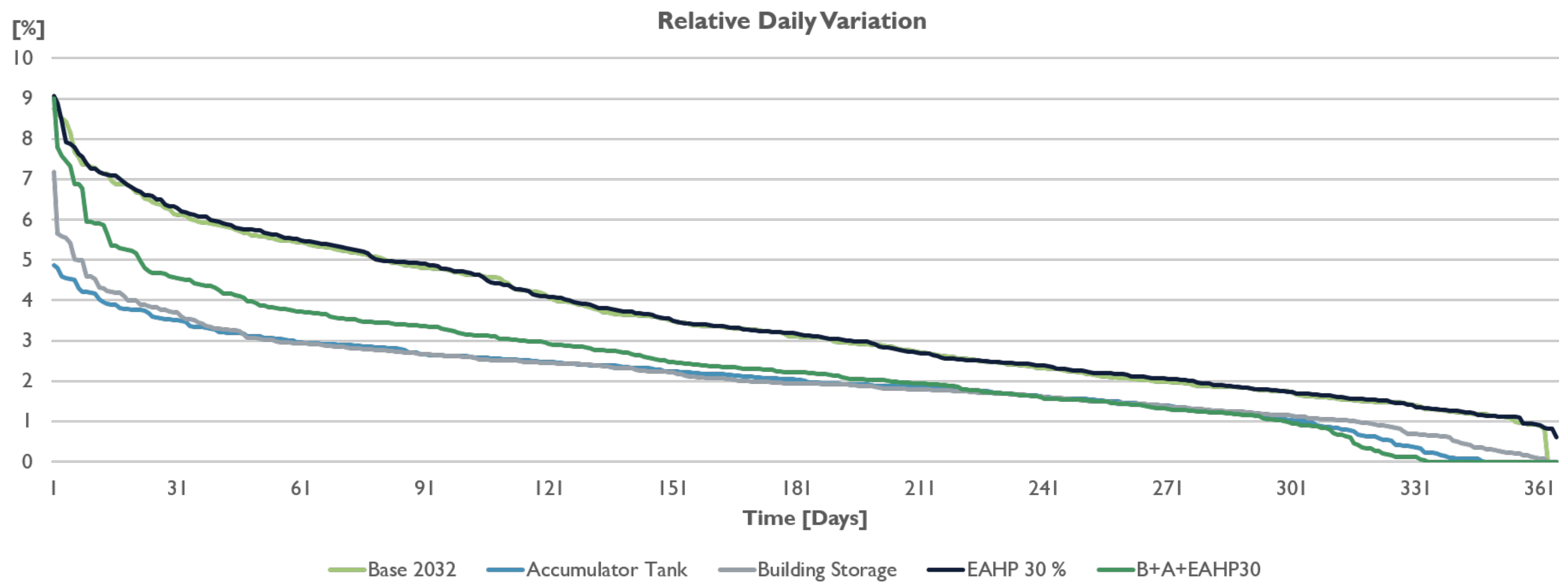


Figure 4.25: Relative daily heat load variation in 2032 if buildings are used as TES, there is an accumulator tank and 30 % of all new and refurbished buildings install an exhaust air heat pump. All results are from the GP electricity scenario.

The relative daily heat load variation achieved in the combination case is higher than in the two individual storage cases. This is likely due to the fact that the system is optimised for the least possible total system cost. With the combined power capacity of the two storages, the output can be increased in hours with low demand in order to just avoid the start-up or continuous operation an expensive plant. The increase in heat generation when charging is then higher than what the decreased heat load is when discharging and the heat load variation becomes higher. However, overall costs are decreased.

4.7 Sensitivity Analysis

Several sensitivity analyses were performed during this thesis to highlight the impact that changes to some of the assumptions has on the overall performance of the district heating system.

4.7.1 Sensitivity Analysis: Price of bio gas

The heat generation per plant from the base case and the two sensitivity analyses where the bio gas fuel price were defined as 500 and 900 SEK/MWh_{fuel} is presented in figure 4.26. The electricity scenario used here is the GP-scenario. The excess heat and the bio-fuelled CHPs are excluded from the figure below because they basically did not change their amount of generation.

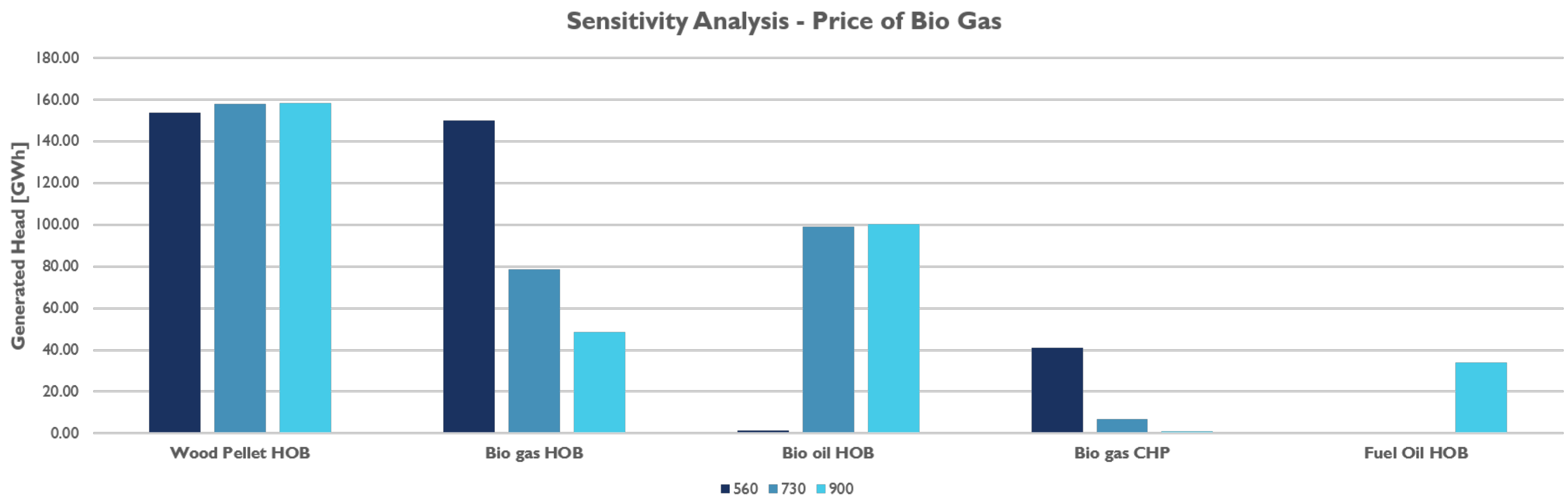


Figure 4.26: Heat generation per plant with excess heat and bio-fuelled CHP excluded.

The first thing to be noted in figure 4.26 is that with more expensive bio gas prices there is a risk of having to use fossil fueled heat generation units at peak loads, unless an active decision of operating a more expensive heat generation unit is made. Lower price of bio gas increased the fuel use substantially, the total heat generated from bio gas sources increases by 124% compared to the base case. Most of this increase is due to the fact that the HOBs that runs on bio gas have a lower fuel price than the ones running on bio oil thus replacing most of the bio oil heat generation. The heat generation from Bio gas CHP increase by a factor of 6 but still the total heat generated in the Bio gas CHP is very small compared to the levels in 2012.

4.7.2 Sensitivity Analysis: No new bio-fuelled CHP

The influence of the new bio-fuelled CHP was to be assessed by removing it from the heat generation model. By removing the CHP less cheap base and intermediate heat generation is available, this increased the total system running cost and the cost difference between the base case and the no-chp scenario is presented in table 4.19.

Table 4.18: Cost difference between the no-CHP scenario and the base case.

El. Scenario	Cost difference [MSEK/year]
GP	+ 150(+34,2%)
RP	+ 97(+20,8%)
CM	+ 156(+35,7%)

The largest increase in running cost are found in the GP and CM scenarios which have higher average electricity prices. The increase in running costs are mainly due to heat being generated in more expensive plants as well as revenue from sold electricity is lost when the CHP is not available. The amount of heat generated per plant can be seen in figure 4.27 and the increased heat generation in HPs and HOBs can be observed.

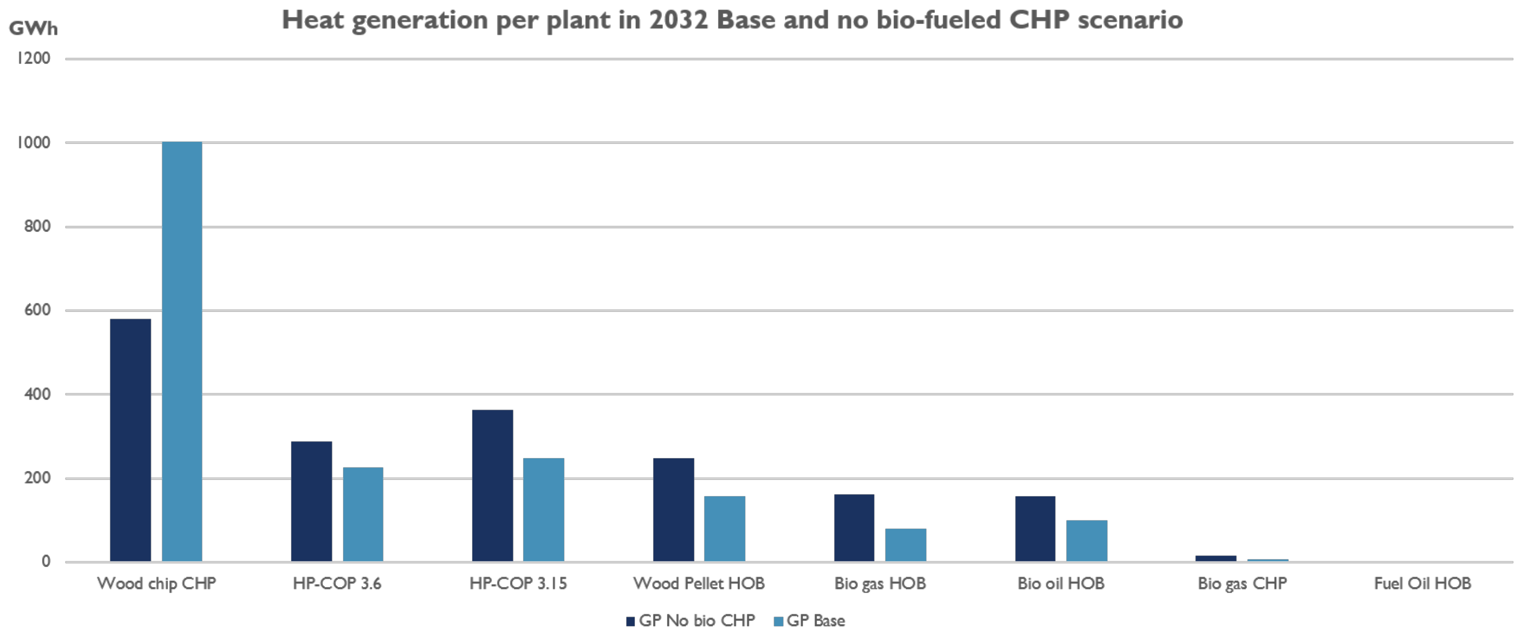


Figure 4.27: Heat generation for the base case and sensitivity analysis with bio-fuelled CHP removed.

Even without the bio-fuelled CHP the heat generation is still free from carbon emissions. However the amount of heat generated from bio gas has increased by 110 % with a total heat generation of 178 GWh. This additional supply of bio gas should be compared with the amount of bio gas available in 2032. The results from this sensitivity analysis shows that the district heating system can be operated without the new bio-fuelled CHP but at greatly increased total running cost and higher dependence on bio gas. The bio-fuelled CHP is definitely a tool for generating heat at low associated carbon emissions while doing so at a competitive cost.

4.7.3 Sensitivity Analysis: Price of electricity certificates

The last sensitivity analysis revolved around the price of electricity certificates. An assumption regarding the price of future electricity certificates was made by the authors in 3.2.1.3, which is associated with uncertainties. Therefore the effect of different prices of electricity certificates were tested. Two different price levels were examined a zero price and a price of 350 SEK/certificate. The total cost difference compared to the base case with a certificate price of 120 SEK is presented below.

Table 4.19: Cost difference between the base case and sensitivity scenarios regarding electricity certificates price.

	Cost difference [MSEK/year]		
El. Scenario	GP	RP	CM
REC 0	+30.7	+16.6	+32.0
REC 350	-65.9	-53.3	-67.3

By lowering the price of electricity certificates the total system cost increases and vice versa when increasing the price. The reason for this is that the CHPs that runs as base and intermediate load generate less revenue when the certificates are worth less. The heat generation per plant can be seen in figure 4.28 below, notice the increase in CHP heat generation when the price of electricity certificates are increased.

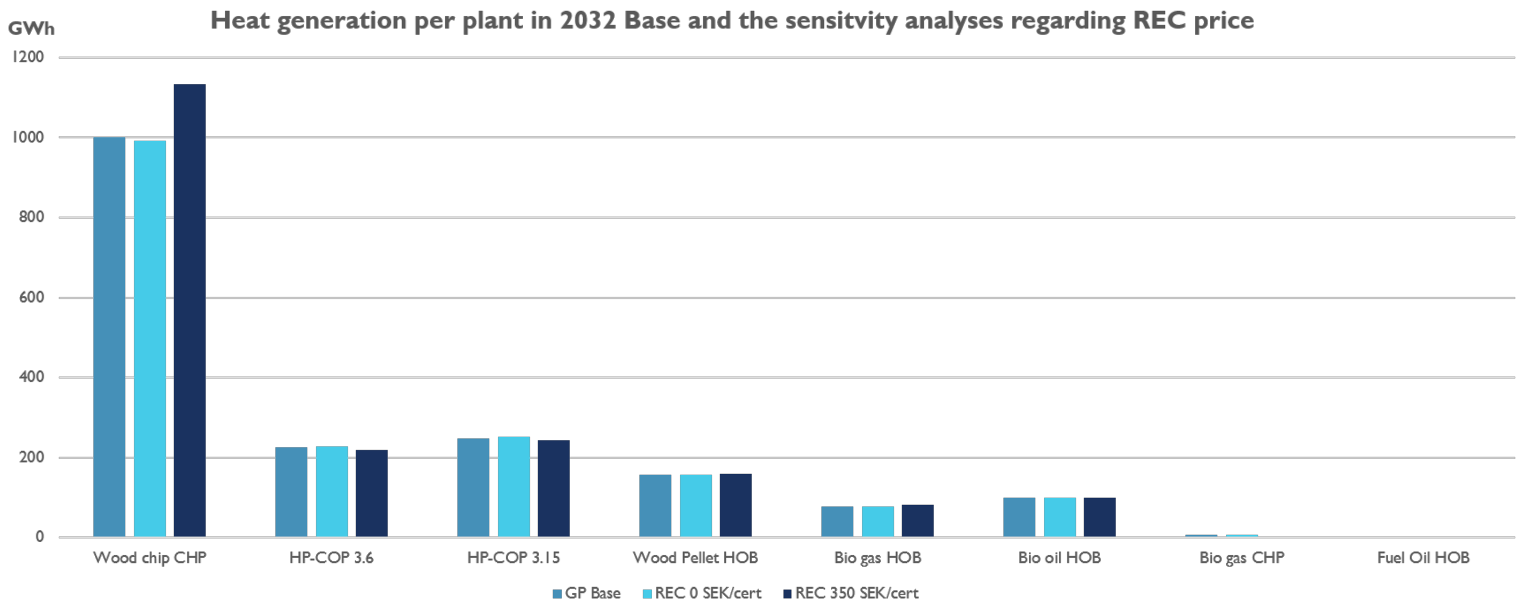


Figure 4.28: Heat generation for the base case and sensitivity analyses of electricity certificates.

The excess heat is not included in the figure above but the increase in CHP generation is balanced by a small decrease in heat generation from excess heat and heat pumps. The total system costs vary quite significantly but the impact on dispatch of heat generation units is quite small. Overall the price of electricity certificates have more impact on the total system running cost then the actual dispatch. In this system the hourly merit order does not change too often due to the increase in REC price, instead hours that already operate CHPs just generate more income.

5

Discussion

The results presented in this thesis are results obtained from models and optimisations. In all work where a model has been used, there will be some limitations in what the model can achieve. This is of course true for this thesis as well. This chapter discusses the major limitations found associated with the model used in this thesis. The chapter is concluded with some remarks regarding possible future similar work.

5.1 Heat demand adaption

An approach was made in this thesis to adapt a heat load profile from 2012 to represent the heat load profile in 2032. The adaption work was limited to the increased energy efficiency in the current building stock together with the new water demand arising from future residential buildings. New space heating demand from future buildings as well as new water usage from commercial buildings, industry and smaller houses were not assessed closely. An assumption was made that new demand would be distributed according to the existing load profile and that this is included in the heat load profile for 2032. The adaption of the load profile could have been improved by including more parameters but the main focus of this thesis was not to adapt the load profile. The intent with adapting the load profile was to give an indication on how the future loads could be distributed. With more time additional work would have been dedicated to investigating more parameters affecting the load profile.

5.2 Weather

All optimizations have been performed with the year 2012 as a basis. The demand for heat is based on the demand for heat in 2012, and electricity prices are based on weather data from 2012. 2012 was a relatively normal year in terms of temperatures, with neither extremely cold nor hot days and nights. Therefore, one should keep in mind that the demand for heat could become higher than what is modelled here, if there is a particularly cold year, peak load boilers would increase their heat generation. If the temperature gets low enough, it is likely that some fossil fuel units will have to be put into operation. A main reason for selecting 2012 as the basis year was that input data was readily available and that the modelled electricity prices for 2032 were based on the weather in 2012.

5.3 Electricity scenarios

Three electricity scenarios have been used throughout the modeling work as a means of establishing a knowledge base regarding the influence of different developments in the electricity sector. The differences when it comes to heat generation in the electricity scenarios are mainly seen in the operation of CHP plants and industrial heat pumps. The GP and CM case have very similar heat generation per plant while the RP case did have more heat generated in heat pumps and less in CHPs due to it having lower electricity prices. For simplicity, the analyses made in this thesis were mainly focused on the GP electricity scenario. The reason for focusing on the GP scenario is because it captures the possible challenges related to more intermittent electricity production and the inherent problems that arises with more fluctuating electricity prices. The CM scenario gave similar results to the GP scenario and the RP scenario was generally more expensive than the other two scenarios. It should be stressed that all electricity prices used in the thesis are obtained from other simulations and should be seen as uncertain.

5.4 Fuel costs

All fuel costs except for the cost of bio gas in the optimisation were set to 2012 levels. In all studied future scenarios, biomass is extensively used for the generation of heat and the cost of it affects the optimisation. In further work, more effort can be put into examining the effect of changed costs of fuels, especially biomass fuels. In this thesis, the level of uncertainties stemming from other factors is already high, and adding projections of fuel costs would only give more uncertainties.

5.5 Perfect foresight

All optimisations have been made with *perfect foresight* given to the optimisation model. This means that when e.g. optimising the heat generation for a full year, the model can make decisions for what to run in January based on what will happen in November. In reality, this will never be the case. Also, the demand for heat and the cost of electricity is known at all time, and there is never any need for back-up generation because of uncertainties in the forecast for demand and electricity prices. This will give a cheaper operation than what will be possible in practice and therefore the results achieved here must be seen as optimistic and as best-case scenarios. However, this dilemma arises in most optimization problems and is hard to avoid.

5.6 Optimisation time horizon

In order to reduce computation time for the optimizations, the accumulator- and building TES cases were divided into shorter optimization periods. In the accumulator case, a little more than a month were optimized at a time, while for the building TES case, even shorter optimization periods were used. As a result of this, the TES in both cases will be emptied by the end of each optimisation period. This obviously differs from how the storages would be operated in practice. However, both storages are able to charge and discharge quite fast in comparison to their respective energy storage capacity. This means that not more than one full charge cycle per optimisation period is affected by the shorter optimisation period. In relation to the number of full charge cycles per year, this is an acceptable loss of precision for the sake of computational time.

5.7 Availability of excess heat

The results of this thesis show that Göteborg Energi indeed have a good opportunity to become fossil-free by 2032 but this depends to a very large extent on the availability of large amounts of cheap excess heat. One could also discuss exactly how fossil-free the excess heat really is. The major part of the excess heat comes from oil refineries that produce a product that is certainly not fossil free. The incineration of municipal waste is associated with emissions as well. In a broad perspective, society is more and more trying to avoid the use of oil products and the assumption that excess heat will be available from oil refineries by 2032 can be questioned. Also, the heat made available from waste incineration may decrease if people start to reduce the waste that can be incinerated because of less packaging material and a more extensive sorting of recyclable waste. On the other hand, the population in the Gothenburg is projected to increase, which would mean that there will be more municipal waste available. Additionally, it is not implausible that new sources of excess heat may become available in the future, for example newly established industries and server halls.

5.8 Modeling of distribution network

The modeling work have not taken into account problems with distributing the generated heat. The model only generates the amount of heat needed in the system in order to supply the demand for heat. How the heat is distributed to the different parts of the district heating network is not investigated in this thesis. Associated with this is also the calculation of daily heat load variations, which are performed on the entire system assuming equal distribution of heat load variations in the heat generating system. However the actual heat load variation experienced by plants and substations could be much larger or smaller depending on where the variations arise.

5.9 Economic evaluation

When assessing the economic performance of all studied measures, only a simple payback period have been calculated. In practice, one should also take an interest rate and economic lifetime of the investment in to consideration. However, when comparing multiple investments which is done here, a simple payback period at least gives a first indication if one investment is very much better or worse than the others. The initial investment costs calculated here are rather rough estimates, and adding a interest rate and economic lifetime would add even more uncertainty to the analysis, as one would have to estimate those figures in a future scenario. In addition, the estimated achieved cost savings must also be seen as merely indications of trends and not be taken for absolute figures.

5.10 Buildings as TES

One major source of error in the optimisation of the buildings used as TES is that there are no losses modelled in the building TES. This was done since it was believed that the increase and decrease of heat losses from the two storages in the buildings would cancel out each other over the course of a year, and for simplicity losses were neglected. This is likely to overestimate the potential of the building TES and in future work, a heat loss should be added to the building TES model. There is also an ethical dilemma associated with the use of buildings used as TES, as it is operated in this optimisation. The building TES is used as a heat sink for CHPs in order to increase profits for the owner of the CHP, i.e. Göteborg Energi. It is debatable if residents would be willing to let Göteborg Energi control their indoor climate, so that Göteborg Energi can make more money. On the other hand, the marginal cost of heat is decreased because of this, and if there is a business model in place where customers pay for heat based on actual marginal cost, they would also benefit from this.

5.11 Investment cost of Seasonal TES

The cost of a seasonal storage is very difficult to estimate, because of its scale and that there are few similar projects performed that are comparable. The calculated cost for the seasonal storage in this thesis is merely estimated from the required water volume in order to store 200 GWh of heat. This is done based on the assumption that the temperature difference needed is 50°C. 50°C is the temperature difference in the present DH network of Gothenburg, but in a future system, the temperature difference might very well be lower. For future DH systems, it is considered that supply and return temperatures will be substantially lower than what they are today (Lund et al. 2014). With a smaller temperature difference, the needed water volume would be smaller and thereby, the cost of the storage would also be smaller. A 40 % decrease in temperature difference is stated as plausible by (Lund et al. 2014), which would in turn give a 40 % decrease of the cost for excavating a seasonal heat storage.

5.12 Exhaust air heat pumps performance and cost

The performance of the heat pumps are calculated in a fairly simple manner with the COP-value being a function of only the outdoor temperature. This simplified approach of determining COP-values in the model stems from the outdoor temperature being directly linked to the radiator temperatures in a building and thus related to the temperature levels in the heat pump. Only two different simulations of a heat pump in the area of Gothenburg were used for acquiring the COP versus outdoor temperature function and more heat pumps could have been investigated in order to get more representative values. With additional data set of COP-values for different exhaust air heat pumps a diverse EAHP stock could have been used instead of using an average of two simulations that resulted in identical performance of all the exhaust air heat pumps being deployed. Furthermore no decrease in efficiency related to running the heat pumps on part load were modeled. However, the EAHPs are usually run to their full capacity in the different scenarios that will mean that a decrease in efficiency would have limited impact on the operation characteristics.

5.13 Future work

This thesis has a wide scope and the studied scenarios can be investigated further and modelled with a higher degree of detail. The authors recommend that future similar work focuses on one or two of the measures studied in this thesis and model them with more sophisticated methods. All investment costs are roughly estimated from figures found in literature and a more extensive survey among with basis in industry is recommended in order to get more up-to-date figures regarding costs.

Further, it would be interesting to further investigate the size and design of the different TES measures that have been investigated in this thesis. A similar optimisation study could have the objective to determine the optimal size of a TES, based on minimal system cost. For an accumulator tank, further work would include investigations regarding the placement of the tank in the DH system, as the benefits from an accumulator tank can be increased by placing it strategically in the system. For buildings used as TES, it is preferable that an effort is made to refine the model of the deep and shallow storage. I this thesis, no additional heat losses are included in the model of the building storage, which likely overestimates its potential.

The modeling regarding exhaust air heat pumps in this thesis showed that deploying exhaust air heat pumps in the future could prove economically viable. A significant deployment of EAHPs could potentially have significant impact on the heat deliveries and the associated income for a utility. It would therefore be interesting to further investigate what different owner structures and business arrangements that could be used when acquiring a EAHP. An example could be a utility owned EAHP that could be centrally operated after the marginal generating cost and the building only pays for the delivered heat.

6 Conclusions

In this thesis four main areas of technologies and strategies that are possible to deploy by 2032 have been surveyed. Among these are three different thermal storage technologies and the influence of exhaust air heat pumps. A base model for the district heat generation in 2032 have been developed as a means for comparing different future scenarios that incorporate one of the technologies mentioned above or a combination of them. The comparison between the base model and scenarios aims to evaluate the economical effect that the new scenarios would have on the future district heating system as well as the consequences for the dispatch of heat generation units. Furthermore three different electricity scenarios were included in this study in order to capture the influence that the future electricity system will have on the heat generation through synergy effects in CHPs and HPs.

It is possible for Göteborg Energi AB to have a fossil-free generation of heat by the year 2032 if the measures outlined in the BioPrio initiative are realized. However, the cost of supplying Gothenburg with heat in 2032 could be decreased with a deployment of exhaust air heat pumps or thermal storage options.

The sensitivity analyses performed shows that the a high price of bio gas could potentially create situations where one would operate fossil-fuelled heat generation units. A way to counter this is to run other more expensive but non-fossil fuelled units. Further, if no new bio-fuelled CHP is constructed the system running cost would increase between 20-35% and more heat would be generated in the heat pumps and HOBs. However this would not result in heat being generated in fossil fuelled units, instead heat is generated in HOBs that run on bio oil, wood pellets and bio gas. The last sensitivity analysis showed that a the price of electricity certificates have mainly an impact on the operation of CHP plants. With a high price the sold electricity in CHP plants will help reduce the cost of supplying heat to Gothenburg and vice versa.

Modeling of the different electricity scenarios show that higher future electricity prices results in lower system running costs. The sensitivity analysis where the new bio-fuelled CHP is not constructed shows that the relative increase in system running costs are greater for electricity scenarios with higher average prices. Sold electricity helps to greatly reduce the cost of generating heat in the system and higher electricity prices favors the operation of CHPs.

One of the major conclusions drawn in this thesis is that the bio gas CHP plant will not be used in the future, at least not if heat is to be generated at a minimum system cost. The start-up cost and high cost of fuel associated with running bio gas CHP on bio gas limits the use of it substantially. In most scenarios, bio gas CHP is only run for a few hours during a year and it can be argued that bio gas CHP should be decommissioned by the year 2032.

By adding any type of thermal energy storage to the Gothenburg district heating system, cost savings are achieved compared to when there is no TES available. In addition to the direct cost savings calculated from running costs of plants, one can also expect additional cost savings in the form of avoided maintenance. The maintenance costs can be avoided by implementing TES since the daily heat load variations are reduced, making it possible to run heat generation plants at more constant loads. This decreases the wear on components in the plants. Using buildings as thermal energy storage can give similar system benefits as an accumulator tank at a much lower investment cost. However, the implementation of this faces other problems such as price models for customers and justifying that a company controls the indoor climate of its customers.

A seasonal thermal energy storage will give substantial benefits in terms of reduced running costs of the heat generation and reduced heat load variations. The investment cost of a seasonal storage is however very high and it is hard to initialise such a large project of which there is little experience. Gothenburg is nonetheless a very strong candidate for this type of thermal energy storage, considering that there are such large quantities of unused excess heat during large parts of the year.

Deploying exhaust air heat pumps in combination with district heating results in lower total system running costs for supplying heat but introduces additional heat load variations. The ownership and operational structure of the EAHPs will determine the economical effect on the utility company. With owners and operators that are external to Göteborg Energi heat deliveries and income will be lost. However, with Göteborg Energi as the operator and or owner heat could be supplied at a lower cost and savings that arise could benefit both Göteborg Energi and the building owners that utilize a EAHP. The decision if Göteborg Energi should pursue ownership of EAHPs needs to be made with considerations of system savings and total investment costs. A simple payback period in this thesis showed for a small to moderate deployment of EAHPs that the payback period to be in the range of 3.6 - 4.5 years.

Finally, it is concluded that Göteborg Energi has a good opportunity to become fossil free by the year 2032, but that this to a very large extent depends on the availability of cheap excess heat. The large amounts of excess heat used in the Gothenburg district heating system makes it unique in Sweden, and especially a seasonal thermal energy storage would have a large impact on the generation of district heat.

Bibliography

Akkaya, B M. and Romanchenko, D. (2013). *Modeling and analysis of a district heating system containing thermal storage*. Examensarbete. Institutionen för energi och miljö, Avdelningen för energiteknik, Chalmers tekniska högskola.

Åström, C. (2011). *Solvärme med säsongslager i Lyckebo - Utredning av värmeförluster och dimensionering av solfält*. Uppsala Universitet. Teknisk-naturvetenskaplig fakultet, Examensarbete UPTEC ES 11 032.

Averfalk, H., Ingvarsson, P., Persson, U., and Werner, S. (2014). "On the use of surplus in district heating systems". In: *The 14th International Symposium on District Heating and Cooling*. DOI: http://dx.doi.org/10.1016/j.apenergy.2011.12.045.

Berkel, J., Rindt, C., and Steenhoven, A. (1999). "Modelling of two-layer stratified stores". In: *Solar Energy*.

Bogdan, Z. and Kopjar, D. (2006). "Improvement of the cogeneration plant economy by using heat accumulator". In: *Energy* 31.13. DOI: 10.1016/j.energy.2006.01.012.

Börjesson, P., Lundgren, J., Ahlgren, S., and Nyström, I. (2013). "Dagens och framtidens hållbara biodrivmedel". In: *Underlagsrapport från f3 till utredningen om fossilfri fordonstrafik. Rapport f3.*

Boss, A. (2012). *fjärrvärmecentral och frånluftsvärmepump i kombination*. URL: http://www.svenskfjarrvarme.se/Global/FJ%C3%84RRSYN/Rapporter%5C%20och%5C%20resultatblad/Rapporter%5C%20teknik/2012/2012_11%5C%20Fr%C3%A5nluftv%C3%A4rmepump%5C%20och%5C%20fj%C3%A4rrv%C3%A4rmecentral%5C%20i%5C%20kombination/Fj%C3%A4rrv%C3%A4rmecentral%5C%20och%5C%20fr%C3%A5nluftsv%C3%A4rmepump.pdf (visited on 09/17/2016).

Boverket (2010). *Energi i bebyggelsen – tekniska egenskaper och beräkningar – resultat från projektet BETSI*. URL: http://www.boverket.se/globalassets/publikationer/dokument/2011/betsi-energi-i-bebyggelsen.pdf (visited on 07/20/2016).

– (2014). *Värme och varmvatten*. URL: http://www.boverket.se/sv/byggande/bygg-och-renovera-energieffektivt/energikrav/varme-och-varmvatten/ (visited on 09/11/2016).

Brunström, C, Eftring, B, and Claesson, J (1987). "The Lyckebo-project–Heat Losses from the rock cavern storage". In: *Report RUL-FUD-B 87. Vattenfall, Sweden.*

Carlsson, J. (2016). *Marginal Price Control of Buildings Utilised as Thermal Energy Storage*. Chalmers University of Technology.

Dincer, I. (2002). "On thermal energy storage systems and applications in buildings". In: *Energy and Buildings* 34.4. DOI: http://dx.doi.org/10.1016/S0378-7788(01)00126-8.

Dotzauer, E. (2002). "Simple model for prediction of loads in district - heating systems". In: *Applied Energy* 73. DOI: 10.1016/S0306-2619(02)00078-8.

Energimarknadsinspektionen (2014). *Så sätts ditt elpris*. URL: http://ei.se/Documents/Publikationer/fakta_och_informationsmaterial/Sa_satts_ditt_elpris.pdf (visited on 09/11/2016).

Energimyndigheten (2015a). *Elkundens bidrag till förnybar elproduktion*. URL: http://www.energimyndigheten.se/fornybart/elcertifikatsystemet/om-el%5C%5Ccertifikatsystemet/elkundens-bidrag-till-fornybar-elproduktion/ (visited on 11/26/2015).

– (2015b). *En svensk-norsk elcertifikatsmarknad*. URL: http://www.energimyndigheten.se/fornybart/elcertifikatsystemet/om-elcertifikatsystemet/en-svensk-norsk-elcertifikatsmarknad (visited on 11/26/2015).

– (2012). *Energy in Sweden - facts and figures 2012*. Energimyndigheten.

– (2016a). *Kvotnivåer*. URL: http://www.energimyndigheten.se/fornybart/elcertifikatsystemet/kvotpliktig/kvotnivaer/ (visited on 05/26/2016).

– (2016b). *Kvotnivåer*. URL: https://cesar.energimyndigheten.se/WebPartPages/AveragePricePage.aspx (visited on 08/16/2016).

– (2014). *Statistik*. URL: http://energimyndigheten.se (visited on 09/23/2016).

European Comission (2016). *2030 climate & energy framework*. URL: http://ec.europa.eu/clima/policies/strategies/2030/index_en.htm (visited on 09/23/2016).

Frederiksen, S. and Werner, S. (2013). *District heating and cooling*. 1st ed. ISBN: 9789144085302.

Gadd, H. and Werner, S. (2013). "Daily heat load variations in Swedish district heating systems". In: *Applied Energy* 37.2. DOI: 10.1016/j.enpol.2008.10.003.

Göransson, A., Johnsson, J., Sköldberg, H., Stridsman, D., Unger, T., and Westholm, E (2009). *"Fjärrvärmen i framtiden - behovet"*. (in Swedish). Svensk Fjärrvärme AB. URL: http://www.svenskfjarrvarme.se/Global/FJ%C3%84RRSYN/Rapporter%5C%20och%5C%20resultatblad/Rapporter%5C%20omv%C3%A4rld/2009/Fj%C3%A4rrv%C3%A4rmen%5C%20i%5C%20framtiden.pdf/.

Göteborg Energi (2012). *Års- och hållbarhetsredovisning 2012*. Göteborg Energi.

– (2014). *Års- och hållbarhetsredovisning 2014*. Göteborg Energi.

Göteborg Energi (2016a). *Bioprio - fossilfri fjärrvärme till 2030*. URL: `https://www.goteborgenergi.se/Foretag/Produkter_och_tjanster/Fjarrvarme/Priser/Bioprio` (visited on 09/05/2016).

– (2016b). *FAQ Bioprio och klimatåtgärder för minskade lokala CO2-utsläpp*. URL: `http://intranet.goteborgenergi.se/Goteborg-Energi/Nyhetsarkiv/Koncernnyheter/Fjarrvarmepris-och-bioprio` (visited on 06/13/2016).

– (2016c). *Våra anläggningar*. URL: `http://www.goteborgenergi.se.` (visited on 06/29/2016).

Gretzer, E. M., Spakovszky, Z. S., and Waitz, I. A. (2006). *H3.4 Refrigerators and Heat Pumps*. MIT. URL: `http://web.mit.edu/16.unified/www/SPRING/propulsion/notes/node24.html`.

Hallqvist, K. (2014). *Högtempererat borrhålslager för fjärrvärme*. Uppsala Universitet. Teknisk-naturvetenskaplig fakultet, Examensarbete UPTEC ES 14033.

Heier, J. (2013). *Energy Efficiency through Thermal Energy Storage: Possibilities for the Swedish Building Stock*. KTH Royal Institute of Technology.

Hillström, C-G. and Åstrand, L. (1985). *Solvärme med säsongvärmelagring i berg för 550 lägenheter i Lyckebo, Uppsala. Från idé till idrifttagning. R 43:1985*. Byggforskningsrådet, Stockholm.

Hjalmarsson, L (2016). “Personal communication with Lennert Hjalmarsson at Göteborg Energi”.

Incropera, F., Lavine, A., Bergman, T., and DeWitt, D. (2013). *Principles of heat and mass transfer*. Wiley. ISBN: 9780470646151.

Johansson, C. and Wernstedt, F. (2010a). “Heat load reductions and their effect on energy consumption”. In: *12th International Symposium on District Heating and Cooling*, pp. 244–249.

Johansson, C., Wernstedt, F., and Davidsson, P. (2010b). “Deployment of agent based load control in district heating systems”. In: *First International Workshop on AgentTechnologies for Energy Systems, Canada.*

Johnsson J. Göransson, A. and Ludvig, K. (2016). *"Fjärrvärmeleveranser till 2035 i Göteborg, Partille och Ale"*. Profu AB.

Kärkkäinen, S. et al. (2003). “Demand side management of the district heating systems”. In: *VTT Research Notes* 2247.

Kensby, J. (2016). “Personal communication with Johan Kensby at Göteborg Energi/Chalmers”.

Kensby, J., Trüschel, A., and Dalenbäck, J. (2014). “Utilizing Buildings as Short-Term Thermal Energy Storage”. In: *The 14th International Symposium on District Heating and Cooling, September 7th to September 9th, 2014, Stockholm, Sweden.*

Kensby, J., Truschel, A, and Dalenbäck, J.O. (2016). *Heat Source Shifting in Buildings Supplied by District Heating and Exhaust Air Heat Pump*. Division of Building Services Engineering, Department of Civil and Environmental Engineering at Chalmers University of Technology.

Kensby, J., Trüschel, A., and Dalenbäck, J.-O. (2015). "Potential of residential buildings as thermal energy storage in district heating systems - Results from a pilot test". In: *Applied Energy* 137. DOI: 10.1016/j.apenergy.2014.07.026.

Kraftringen (2015). *Om Örtoftaverket*. URL: http://www.kraftringen.se/Om-Kraftringen/Om-foretaget/Anlaggningar/Ortoftaverket/Om-Ortoftaverket/ (visited on 06/30/2016).

Lee, K S. (2013). "Cavern Thermal Energy Storage Systems". In: *Underground Thermal Energy Storage*. Springer.

Lindholm, A. and Ångström, A. (2011). *Konsekvenser av tredjepartstillträde till fjärrvärmenäten*. Fjärrsyn. URL: http://www.svenskfjarrvarme.se/Global/FJ%5C%C3%5C%84RRSYN/Rapporter%5C%20och%5C%20resultatblad/Rapport%5C%20marknad/2011/Konsekvenser%5C%20av%5C%20tredjepartstilltr%5C%C3%5C%A4de%5C%20till%5C%20fj%5C%C3%5C%A4rrv%5C%C3%5C%A4rmen%5C%C3%5C%A4ten.pdf.

Lund, H., Werner, S., Wiltshire, R., Svendsen, S, Thorsen, J., Hvelplund, F, and Vad Mathiesen, B. (2014). "4th Generation District Heating (4GDH): Integrating smart thermal grids into future sustainable energy systems". In: *Energy* 68. DOI: http://dx.doi.org/10.1016/j.energy.2014.02.089.

Mörtstedt, Sten-Erik and Hellsten, Gunnar (1999). *Data och diagram:[energi-och kemitekniska tabeller]*. Esselte studium.

Nordell, B. (1994). *Borehole heat store design optimization*. Luleå tekniska universitet,

Nordell, B., Grein, M., and Kharseh, M. (2007). "Large-scale utilisation of renewable energy requires energy storage". In: *Proceedings of international conference for renewable energies and sustainable development (ICRESD_07)*.

Nordpool (2011a). *Day-ahead market*. URL: http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/ (visited on 09/11/2016).

– (2011b). *Price formation*. URL: http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/Price-formation/ (visited on 09/11/2016).

Nyholm, E. and Steen, D. (2014). "Can demand response mitigate the impact of intermittent supply?" In: *Systems Perspectives on Renewable Power*. Chalmers University of Technology.

Olsson, D. (2016a). "Personal communication with Daniel Olsson at CIT Energy Mangement AB".

– (2016b). *Värmeåtervinning av frånluft i befintliga flerbostadshus - Påverkan på fjärrvärme- och elleveranser*. (in Swedish). CIT Energy Management AB.

Olsson, E (2016). “Personal communication with Erik Olsson at Danfoss”.

Pinel, P., Cruickshank, C.A., Beausoleil-Morrison, I., and Wills, A. (2011). “A review of available methods for seasonal storage of solar thermal energy in residential applications”. In: *Renewable and Sustainable Energy Reviews* 15.7. DOI: 10.1016/j.rser.2011.04.013.

Schäfer, A., Grote, F., and Moser, A. (2012). “Optimization of Thermal Energy Storage Systems in Distributed Generation Systems”. In: *Zeitschrift für Energiewirtschaft* 36.2. DOI: 10.1007/s12398-012-0075-3.

Skogfält, M. (2009). *Dimensionering av ackumulatortank vid LKABs förädlingsverk i Kiruna – för uppvärmning av processvatten och minskad oljeanvändning.* Umeå Universitet. Examensarbete.

Sköldberg H. Unger, T. and Holmström, D. (2015). *El och Fjärrvärme - samverkan mellan marknaderna.* (in Swedish). Energiforsk. URL: http://www.energiforsk.se/nyhetsarkiv/samverkan-mellan-el-och-fjarrvarme/.

Sommansson, C. (2016). “Personal communication with Claes Somansson at Göteborg Energi”.

Steen, D, Stadler, M., Cardoso, G., Groissböck, M, DeForest, N., and Marnay, C. (2015). “Modeling of thermal storage systems in {MILP} distributed energy resource models”. In: *Applied Energy* 137. DOI: http://dx.doi.org/10.1016/j.apenergy.2014.07.036.

Svensk Fjärrvärme (2003). *Effektutjämning med ackumulatortank.* URL: http://www.svenskfjarrvarme.se/Global/Rapporter%5C%20och%5C%20dokument%5C%20INTE%5C%20Fj%C3%A4rrsyn/FOU-rapporter%5C%20INTE%5C%20Fj%C3%A4rrsyn/Hetvattenprogrammet,%5C%20rapporter/2003/Kopplingsprinciper_for_fjarrvarmecentral_FOU_2003-94.pdf (visited on 09/17/2016).

– (2010). *Effektutjämning med ackumulatortank.* URL: http://www.svenskfjarrvarme.se/Medlem/Fokusomraden-/Fjarrvarldens-omvarld/Energieffektivistering/Energieffektiviseringsexempel/Intern-energieffektivisering/Effektutjamning-med-auckumulatortank/ (visited on 09/08/2016).

Svenska Petroleum- och Biodrivmedel Institutet (2016). *Energiinnehåll, densitet och koldioxidemission.* URL: http://spbi.se/blog/faktadatabas/artiklar/berakningsmodeller/ (visited on 08/22/2016).

Svenskenergi (2016). *Elpriser och skatter.* URL: http://www.svenskenergi.se/Elfakta/Elpriser-och-skatter/ (visited on 09/16/2016).

Utzinger, M. and Wasley, J H. (2016). *Vital Signs - Building balance point.* URL: http://vitalsigns.ced.berkeley.edu/res/downloads/rp/balance_point/balance_point_big.pdf (visited on 09/11/2016).

Verda, V. and Colella, F. (2011). “Primary energy savings through thermal storage in district heating networks”. In: *Energy* 36.7. DOI: 10.1016/j.energy.2011.04.015.

Zinko, H. and Gebremedhin, A. (2008). *Säsongvärmelager i kraftvärmesystem (Fjärrsyn Rapport 2008:1*. Svensk Fjärrvärme.

Zinn, E. (2016). "Personal communication with Eric Zinn at Göteborg Energi".