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Modelling heat and electricity supply in multifamily buildings with energy storage and solar PVs

Master's thesis in Applied Physics

FILIPPA BORG

Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2015

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Abstract

The purpose of this thesis is to investigate how buildings with solar PVs and heat and electricity storage can be operated. The building considered has both a district heating connection and heat pumps, and can buy district heating and electricity on spot price. A model has been created to optimise the energy supply in the building by minimising the running cost utilising the energy storage, the price fluctuations and the produced solar electricity. The conclusion is that the combination of electrical and thermal storage works well, both are useful and contributes to the cost reduction. The running cost can be reduced with 24 % with a thermal storage capacity of 1 000 $\mathrm{kWh_{th}}$ and an electrical storage of 300 $\mathrm{kWh_{el}}$. The storage capacities reduces the dependencies from the electricity grid and the district heating network. With an electrical storage of 300 $\mathrm{kWh_{el}}$, the building can be self-sufficient on electricity 57 % of the hours of the year, while without any storage only 29 %. The decrease in running cost is largest when increasing the electrical storage, since a larger share of the produced PV electricity can be utilised in the building which saves not only the spot price of electricity, but also taxes and grid fees. Due to the large fluctuations in the marginal district heating cost, the share of heat supplied by district heating increases with increased thermal storage. The heat pumps and the district heating can efficiently collaborate. A combination of the two technologies, together with spot price on both electricity and district heating, reduces the running cost of the building regardless of storage size. Utilising energy storage in buildings, as in this thesis, will increase flexibility in the energy system in the building and reduce dependency on the surrounding energy grids.

Keywords: Buildings, heat pump, district heating, modelling, energy storage.

Modellering av värme- och elförsörjning i flerfamiljshus med energilager och solceller
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Sammanfattning

Denna rapport syftar till att undersöka hur byggnader med solceller och värme- och ellager kan styras. Byggnaden i denna rapport är kopplad till fjärrvärmenätet och har installerade värmepumpar och dessutom möjlighet att köpa både el och fjärrvärme på spotpris. En modell har skapats som optimerar energitillförseln i byggnaden genom att minska driftskostnaden med hjälp av energilagren, prisvariationerna och den producerade solelen. Slutsatsen är att kombinationen av el- och värmelager fungerar bra, båda är användbara och bidrar till minskningen av driftskostnaden. Driftskostnaden kan minskas med 24 % med en kombination av ett värmelager på 1 000 $\mathrm{kWh_{th}}$ och ett ellager på 300 $\mathrm{kWh_{el}}$. Lagren minskar beroendet från el- och fjärrvärmenäten. Med ett ellager på 300 $\mathrm{kWh_{el}}$ kan byggnaden vara självförsörjande på el 57 % av timmarna på ett år, medan utan ett lager bara 29 %. Minskningen i driftskostnad är störst vid en ökning av storleken på ellagret, eftersom en större del av den producerade solelen kan användas i byggnaden, vilket inte bara sparar in på spotpriset utan även på skatter och elnätsavgifter. De stora variationerna i marginalfjärrvärmekostnaden ökar andelen värme som tillförs via fjärrvärme, jämfört med vad som tillförs via värmepumparna, med ökad storlek på värmelagret. Värmepumparna och fjärrvärmen kan med fördel användas tillsammans och kombinationen minskar driftskostnaderna i byggnaden oavsett storlek på värmelagret. Genom att använda energilager i byggnader ökar flexibiliteten i byggnadens energisystem och beroendet av de omgivande energinäten minskar.

Nyckelord: Byggnader, värmepump, fjärrvärme, modellering, energilager.

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Filippa Borg, Gothenburg, September 2015

Contents

1
Introduction

To be able to fight global warming, the world needs to reduce the use of fossil fuels. In the energy sector, and especially in the electricity and the district heating (DH) grid, this can be done with higher energy efficiency and smarter utilisation of the energy, such as demand-side management and energy storage. Renewable energy sources together with load shifting and possibilities of energy storage in the energy system are needed for a future fossil free energy sector (Taylor et al., 2012) .

Load shifting and the possibility of storing electricity and heat are important in many ways (Taylor et al., 2012; Borg, 2014; Fritz et al., 2009). The storage possibilities reduce peak demand, which is both cost-efficient and environmentally friendly. Energy storage gives a robust protection against shortage situations, and therefore reduces the need for extra power plants. In a system with a lot of intermittent power production, the advantage of storage capacities increases according to Taylor et al. (2012), because the storage can then act as a balancing power for the fluctuating production.

Distributed storage capacities, placed close to, or at the customer, have many advantages. The storage can be as efficient as a centralised one, and it has a large potential total volume (Taylor et al., 2012). According to recent research by Borg (2014), it is also most profitable from a system perspective to have the electricity storage on the demand side of the grid, behind each customer's electricity meter. This is also favourable for the customer, if paying per hour, who can then shift his/her demand to hours where the energy is cheaper.

One way of utilising the electricity grid and the district heating network in a smarter way is to enable load shifting between the two (Averfalk et al., 2014). The possibility to make heat from electricity makes the combined heat and electricity system more flexible. When the electricity is cheap, for example when there is a lot of wind power, it can be used to produce heat. This makes use of the surplus electricity as well as producing cheap heat. With the ability to use both electricity and district heating for heating in a building, the customer is also less dependent on a specific company or technology.

Distributed power generation such as solar power is even more dependent on energy storage according to Kanamori et al. (2011), since the production cannot be controlled and might not coincide with the demand. With energy storage together with distributed power production, a larger share of the produced energy can be utilised locally and the dependency on the grid is reduced (Hill et al., 2012).

To minimise energy usage in buildings and to handle fluctuations in the district heating system as well as in the electricity system, load shifting together with energy storage can be used. The possibilities for this is modelled in this Master's thesis, which is conducted in conjunction with Göteborg Energi. To be able to analyse the energy use in buildings, a model for energy systems in buildings is developed. The model will typically consider a multifamily building, inspired by Riksbyggen Positive Footprint Housing (PFH), and optimise the energy usage in a building with solar power and energy storage capacities. Riksbyggen PFH is a residential project that will be realised first in the building cooperative brf Viva, in Gothenburg.

1.1 Purpose

The purpose of this thesis is to investigate how new types of buildings, with different energy technologies installed, can be operated. The buildings will have solar power and will be connected to a district heating network and have heat pumps installed. The buildings will also include possibilities for energy storage and posibillities to buy energy on spot price.

The goal is to create a model that will optimise the energy supply in the building from an operational strategic point of view, and to study how the different storage possibilities are, and can be, used.

1.2 Research questions

This report seeks to answer the following questions:

- How can the operational strategies of a building with solar power installations change with possibilities of
  - storing electricity in the building?
  - storing heat in the building and have the possibility to transfer energy from electricity to heat?
  - storing both electricity and heat in the building, and have the possibility to transfer energy from electricity to heat?
- How are the storage capacities utilised in the cases above?
- How does the energy storage affect the energy consumption of the building?
- How does the running cost of the building change with the storage capacities?

1.3 Scope

The modelling is performed with data from the year 2013 and from the Gothenburg region. Weather data, prices and historical user data from reference houses are collected with respect to the place and time mentioned. The specific building, Riksbyggen brf Viva, was chosen as the reference house because of the ongoing planning, with Göteborg Energi as one of the partners, and for helping the decisions when dimensioning the storage capacities in the building. However, the model is general, and input data can be chosen by the user. Values from the surrounding electricity grid and district heating network are used as an input to the model, and are not affected by the optimisation. Analysis is also made with simulated future electricity prices of 2030.

Throughout the thesis, the term storage capacities are used both regarding thermal storage and electricity storage. This is due to the model being technology independent, although losses and capacity limits has been chosen to represent common technologies. The term storage capacity is also used because it refers to the used capacity, and this might not correspond to the installed one (since for example it is disadvantageous to use a Li-ion battery's physical capacity) and because it might include a combination of different technologies like building thermal storage and load shifting.

No installation costs or fixed cost will be considered in this thesis, only running costs. Any power tariff for district heating or electricity is not included. The electricity surcharge, for both selling and buying electricity, is based on 2013 numbers, and can be changed easily in the model.

2
Theory and background

To be able to perform the optimisation as intended in this thesis, some background knowledge is necessary. The chapter starts with a literature review of what others have done in the same field. Explanations of the electricity system in Sweden, with the pricing, as well as the district heating system in Gothenburg is required for the modelling, and are included. Some examples of different energy storage technologies are then presented. Last in this chapter a short introduction to linear programming, which will be used to solve the optimisation problem, is presented.

2.1 Literature review

Several different studies has been made to investigate the usage of electrical storage capacities in the electricity grid. Kanamori et al. (2011) points out that when combining the storage with solar PV (photovoltaic) installations in residential homes, a reduction of the amount of purchased electricity can be made. A UK study by Vytelingum et al. (2010) shows that a battery of 4 kWh, could make consumers on the UK electricity market to save up to 13 % on their electricity bill. The same study also shows that an equilibrium exists to maximise social welfare where 38 % of the UK households would own electrical storage, with an overall annual saving of nearly GBP 1.5 billion.

A study conducted by Elforsk (Borg, 2014) from Falbygden in Sweden investigates electrical storage in the grid together with solar power and charging of electrical vehicles. This shows several benefits with the storage, and indicates that the largest savings potential is for the consumer if the storage is placed behind the consumers own electricity meter.

Fritz et al. (2009) have made an investigation to see in what level consumers are willing to adapt their consumption according to electricity spot prices, called demand response. The study was performed at households with electric heating, and both remotely managed direct load control and indirect load control were tested. The households with indirect load control expected to adapt their consumption according to the price. The study concludes that the indirect customers did not change their demand according to the actual price, but to the expected price, and thus did not hit the lowest price dips. This made the direct regulation more successful.

A report made by Power Circle (Hansson et al., 2014) pays attention to an American study which has identified not less than 21 benefits with having storage capacities in the energy system. The same report by Power Circle illustrates the benefits of having storage capacities in a house, but at the same time concludes that is is not yet profitable, with the prices of September 2014 in Sweden. But if the benefits from the distribution side can be transmitted to the customers, then it might be profitable.

Energy storage together with intermittent power production can be good since the storage can act as a balancing power, for example to handle errors in the forecast production from wind power according to Hansson et al. (2014). Possibilities to lower the cost for the balancing power by SEK 2 million in a year is shown in the report.

Some studies of load handling and/or thermal storage in district heating networks have been made. A pilot test for short term thermal storage has been performed in Gothenburg by Kensby et al. (2014). The test showed that for the specific houses, there was a storage limitation of about 0.1 kWh/m^2 floor area. Another study with automatically controlled load handling by Wernstedt and Johansson (2008), also using buildings as thermal storage, has turned out well, and the overall results presented in the paper promise both economical and environmental benefits as well as a win-win situation for the district heating provider and the customers.

The possibilities of shifting energy from electricity to heat have been investigated in systems where there is an electricity surplus and a district heating network available, and presented in a report by Averfalk et al. (2014). Although it is only cost-efficient under these circumstances, the possibility to shift between electric heating and district hating will always introduce more flexibility to an energy system since it is no longer dependent on the prices of both electricity or district heating. Boss (2012) discusses the benefits and drawbacks of combining district heating and heat pumps in buildings. The study focuses, however, more on how to combine the two and how to install them, and not so much on what to gain when they are both installed.

The conclusion of the report from Power Circle (Hansson et al., 2014) is a recommendation of which system should be most profitable. They advocate more energy efficient (and power efficient) products, intelligent control of the loads, with both thermal storage and electricity storage which in addition is most favourable together with self-produced electricity. They have not yet tested all of this combined.

Reading the articles and reports presented above, it can be seen that investigations regarding thermal storage, or electricity storage have been made, as well as studies on load shifting from electricity to heat. However, no study has been found, as far as the author is aware, that has investigated all these in combination.

2.2 The Swedish electricity market

In an electricity system, supply must always meet demand. The demand can be met by producing new electricity or use already stored energy (e.g. batteries). In Sweden, Svenska Kraftnät is the Transmission System Operator, and has the responsibility for balancing supply and demand in the electricity system. To make supply meet demand, there is an auctioning market called Nord Pool Spot market as described in Fritz and Dahlström (2012). All participants on the electricity market, producers, distributors, system operators, large customers (such as large industries) etc., place bids, for both selling and purchasing electricity, on the spot market for each hour of the following day and the corresponding spot prices for each hour the next day are then presented.

The price of electricity is often set as the variable production cost of the most expensive production plant in operation (no one wants to run their plants unless at least their variable costs are covered for) (Fritz and Dahlström, 2012). The power plant with the most expensive running cost in operation is said to be on the margin. The plant on the margin will only get paid for their operational cost, and not for their capital cost.

The price of electricity varies over time due to a difference in demand and supply and therefore also which power plant is on the margin. The price varies within the day and is usually high in the evening and low at night. The price also varies between the seasons, depending on the weather and between different areas due to limited network capacity.

It is often said that in Sweden we have coal condensing power on the margin, although almost no coal power exists in Sweden. This is because it exists in the European system, which Sweden is a part of, and electricity can be transferred between the different regions. Since Sweden is using all possible hydro power in a year, and can shift when that is used, an increase in demand will lead to import of electricity. What we consume in Sweden therefore affects what is produced in the nearby regions.

In the European Union, there is a trading scheme for carbon dioxide emission called EU ETS (European Union Emission Trading Scheme). The European Commission (2015) describes that the trading scheme exists to lower the CO_2 emission within the EU. The trading scheme makes producing electricity from CO_2 emitting plants more expensive.

In Sweden and Norway there is also a policy instrument in place in order to increase the share of renewable power production in the system. In the Renewable Electricity Certificate (REC) Market (Swedish Energy Agency, 2015), certificates are handed out to producers of renewable power and then sold to those who do not produce any renewable power. Each year, a quota of how much renewable power each producer needs to produce (or buy certificates for), is decided. How and where this renewable power is produced, is up to the market.

Table 2.1: Different parts of the end customer electricity price in Sweden 2013.

	Bought electricity [SEK/kWh$_{el}$]	Sold electricity [SEK/kWh$_{el}$]
Spot price	0.34	0.34
Grid fee/revenue	0.068	0.037
Surcharge	0.03	-
REC	0.027	0.203
Energy tax	0.293	-
VAT	25 %	-
Total	spot + 0.61	spot + 0.23

2.2.1 Electricity price in Sweden

The electricity price payed by the customers is more than just the spot price. As described above the cost for the REC needs to be covered for, as well as grid fees, surcharge for the electricity supplier, energy tax and value-added tax (VAT). In Table 2.1 the different parts of the electricity price in Sweden 2013 is shown. The spot price and the REC (values from Swedish Energy Agency, Cesar (2015)) are set to the mean value of the year, the grid fee is taken from Göteborg Energi, and the surcharge is assumed. Both the energy tax and the VAT is 2013 levels in Sweden (taken from Ekonomifakta (2015)). The grid revenue for the sold PV electricity is taken from Göteborg Energi (2015) and no extra surcharge for the sold electricity is included. The REC for produced solar electricity can be collected regardless of whether the electricity is used in the building or sold to the electricity grid.

For larger customers, like a building cooperative, a power tariff is added to the electricity bill. This will not be included in the model in this thesis, since the power tariff is calculated in different ways by different companies (per month, per year, per rolling 12 month, etc.) and it is also difficult to predict how it will change in the future.

2.3 The district heating system in Gothenburg

The district heating system in Gothenburg is operated by Göteborg Energi and supplies 90 % of the multifamily buildings in Gothenburg, and single family houses, office buildings and shops with space heating and hot tap water (Göteborg Energi, 2015). Compared to most district heating systems in the Nordic region, the system in Gothenburg is large and complex. It has a number of different power plants, including both combined heat and power (CHP) plants and heat pumps. The district heating system is mainly supplied by waste heat and power plants fired by wood chips, wood pellets and natural gas.

The multifamily building considered in this thesis is owned by a building cooperative, which is counted as a company. The district heating prices in Gothenburg for companies consists of three parts: the energy used, the power consumption and the efficiency (how low the return temperature is) (Göteborg Energi, 2015).

2.4 Energy storage technologies

A large number of different energy storage technologies exists, and some are more common than others. Regarding storing electricity it can for example be done with batteries, capacitors, flywheels, pumped hydro storage, hydrogen gas generation or air compression (Messing and Lindahl, 2008). Different storage techniques are suitable for different purposes and in different environments. For a building with solar PV installations it is common to use Li-ion batteries (Kanamori et al., 2011). One reason that makes Li-ion batteries extra interesting in the residential area, is that the market for electrical or hybrid vehicle with Li-ion batteries are growing, and the used batteries from these vehicles can most probably get a second life in buildings.

The thermal storage technologies that is most suitable for buildings are hot water storage tanks and using the building itself as thermal storage. Technologies for underground thermal storage for seasonal variations as well as melted salt methods also exist.

2.5 Linear Programming

Linear programming is an optimisation tool that can be used to achieve the best possible outcome, maximisation or minimisation, of a problem with linear relationships (Chinneck, 2015). A linear programming problem contains an objective function, f, variables, x, and constraints and boundaries for the variables. The problem can be written as equation 2.1, where f, x, b, beq, lb and ub are vectors and A and Aeq are matrices.

$$\min_x f^T x \text{ such that } \begin{cases} A \cdot x \leq b \\ Aeq \cdot x = beq \\ lb \leq x \leq ub \end{cases} \tag{2.1}$$

The goal of linear programming is to minimise $f^T x$ by changing x and without violating the lower (lb) or upper (ub) boundaries or the constraints. There are many different tools for solving linear programming problems, and Matlab will be used in this thesis.

3
Method

This chapter describes the modelled energy system, together with its input data and assumptions. The optimisation model used is also presented together with its constraints and boundaries.

3.1 The modelled energy system

The building modelled in this thesis consists of two energy storage capacities, one for electricity and one for thermal storage, and a solar PV (photovoltaic) installation. Double heating facilities are available in the building i.e. its hot water demand for space heating and tap water can be supplied completely by district heating (DH) or by heat pumps (HP). The building buys both district heating and electricity on spot price, varying from hour to hour. The energy demand of the building in terms of electricity consists of the household electricity of each apartment, the building electricity and charging of a number of electrical vehicles (EVs). A diagram of the modelled energy system in the building can be seen in Figure 3.1. In the figure the red lines represents the electricity grid inside the building, and the green lines are the thermal (hot water) grid in the building. The building will also be able to sell excess electricity from the solar PV to the grid.

3.2 Modelling

To be able to optimise the operational strategies of the building by minimising the running cost, linear programming in Matlab is used. Three systems are considered when the model is made: one with only the electricity system, one with only the thermal system, and a third with the combined heat and electricity system in the building.

When considering only the electricity system in the building, the solar PV installation, the electrical storage and the electricity demand are included. The electricity is bought and sold on hourly prices. No electricity to heat pumps is included, corresponding to an assumption that all heat comes from district heating.

The case for the thermal system included heating supply with both heat pumps and district heating, and a thermal storage. Both the district heating and the

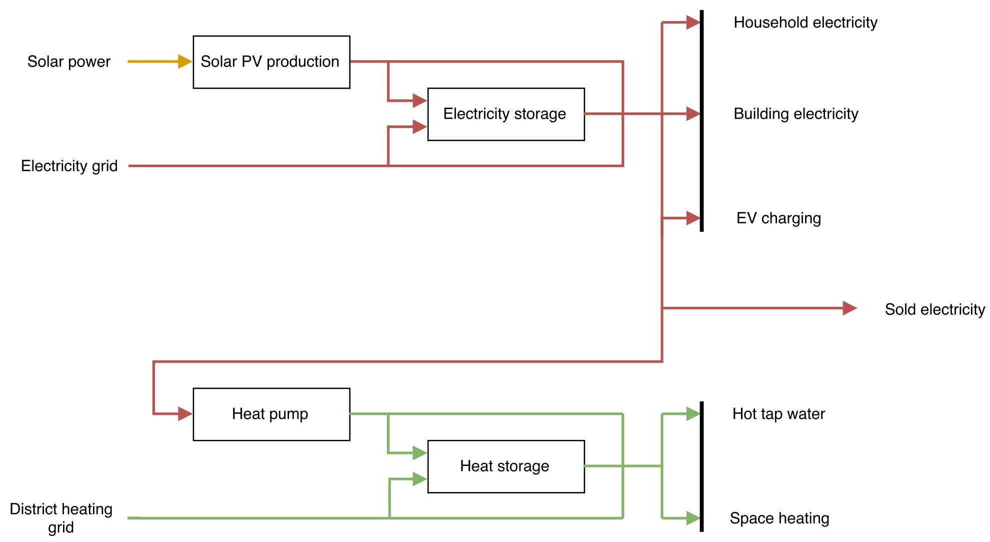


Figure 3.1: The energy system of the building. The red lines show the electricity grid, and the green lines are the thermal grid in the building. To the right is the demand for electricity and heat, and to the left is how these demands are supplied.

electricity to the heat pump are bought on hourly prices. Note that the produced solar electricity is not included here.

Combining these two approaches into a third one makes the entire energy system in the building covered. The combined heat and electricity system in the building includes the ability to store both heat and electricity, and possibilities to transfer loads from electricity to heating with the heat pumps.

3.2.1 Linear programming model

To find the optimal solution of the problem, linear programming is used. The optimisation is done in Matlab, with the built-in function linprog (MathWorks, 2015) . The complete Matlab program can be seen in Appendix B.

The function for the running cost of the electricity system is shown in Equation 3.1. All variables are per hour. $p_{el,\,buy}$ and $p_{el,\,sell}$ are the buy and sell price for electricity in SEK/kWh$_{\mathrm{el}}$, E_{el} is the electricity demand of the building and E_{PV} is the produced PV electricity, both in kWh$_{\mathrm{el}}$. The charge and discharge of the storage are represented as q^+ for charging and q^- for discharging in kW$_{\mathrm{el}}$, q^+_{elG} means charging from the electricity grid while q^+_{PV} that is charging from the solar PV. The direct used solar PV is use_{PV}, in kWh$_{\mathrm{el}}$. $curt_{PV}$ is the curtailed PV, in kWh$_{\mathrm{el}}$, that might appear if a sell limit to the electricity grid exists.

$$\begin{aligned} cost_{el} = \sum_t \Big[p_{el,\,buy}(t) \quad & \cdot [E_{el}(t) + q^+_{elG}(t) - q^-_{el}(t) - use_{PV}(t)] - \\ p_{el,\,sell}(t) \quad & \cdot [E_{PV}(t) - q^+_{PV}(t) - use_{PV}(t) - curt_{PV}] \Big] \end{aligned} \tag{3.1}$$

Equation 3.2 shows the function for the running cost of the thermal system, and as for Equation 3.1, all variables are per hour. $p_{DH,buy}$ is the price for district heating in SEK/kWh$_{\text{th}}$ and E_{th} is the heat demand in the building in kWh$_{\text{th}}$. Charging from the district heating grid, q^+_{DH}, charging from the heat pump, q^+_{HP}, and discharging the thermal storage, q^-_{th}, are all in kW$_{\text{th}}$. use_{HP} is the amount direct used heat that is supplied by the heat pump, in kWh$_{\text{th}}$, and COP_{HP} is the coefficient of performance for the heat pump in kWh$_{\text{th}}$/kWh$_{\text{el}}$.

$$
\begin{aligned}
cost_{th} = \sum_t \Big[p_{DH,buy}(t) \quad & \cdot [E_{th}(t) + q^+_{DH}(t) - q^-_{th}(t) - use_{HP}(t)] + \\
p_{el,buy}(t) \quad & \cdot [q^+_{HP}(t) + use_{HP}(t)]/COP_{HP}(t) \Big]
\end{aligned}
\tag{3.2}
$$

When combining Equation 3.1 and 3.2, the function for the running cost of the combined heat and electricity system in the building is obtained. That is: $cost_{tot} = cost_{el} + cost_{DH}$. The function for the total running cost is displayed in Equation 3.3.

$$
\begin{aligned}
cost_{tot} = \sum_t \Big[p_{el,buy}(t) \quad & \cdot [E_{el}(t) + q^+_{elG}(t) - q^-_{el}(t) - use_{PV}(t) + \\
& \Big(q^+_{HP}(t) + use_{HP}(t)\Big)/COP_{HP}(t)] \; + \\
p_{DH,buy}(t) \quad & \cdot [E_{th}(t) + q^+_{DH}(t) - q^-_{th}(t) - use_{HP}(t))] \; - \\
p_{el,sell}(t) \quad & \cdot [E_{PV}(t) - q^+_{PV}(t) - use_{PV}(t) - curt_{PV}(t)] \Big]
\end{aligned}
\tag{3.3}
$$

When running the model for one year, an optimisation on the best operational strategies for three days is made. The status of the storage after one day (24 h) is saved and used as the new start storage for the next day. The optimisation is then remade, starting on the next day. This method is used to get an estimation of how loaded the storage should be, to be prepared for the coming days. If the next day is sunny, then start the day with an empty battery etc. In a real time model, some kind of weather data can be used, together with a price forecast, to estimate the load level of the storage. If no level of how loaded the storage should be when the day ends is set, the storage will always end the day empty because it is most profitable.

3.3 Input data and assumptions

The building considered in this thesis consists of about 120 apartments divided into three house bodies. The building will be located in the area of Guldheden, in Gothenburg Sweden. All numbers for the total energy demand in the building are from the planning of the building by Riksbyggen. The model is general, though, and can be applied to any building.

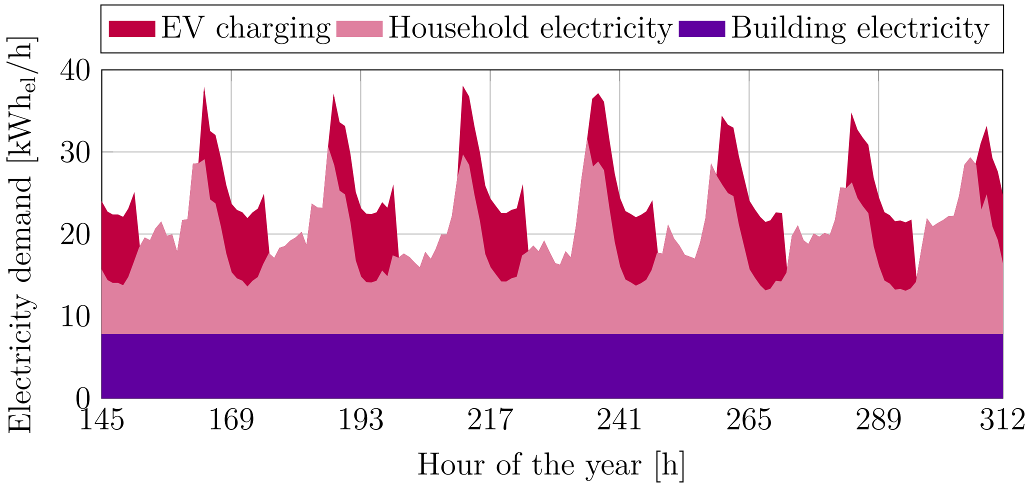


Figure 3.2: Example of the electricity demand in the building for a spring week. The lower part is the building electricity, the middle part is the household electricity and the upper part is the EV charging. The data for the household electricity was provided by Göteborg Energi and is the only one varying through the year. The data for the building electricity and the EV charging is from the planning of Riksbyggen Brf Viva.

3.3.1 The energy demand of the building

The total electricity demand of the building is split in three parts: the building electricity, the household electricity and electricity for charging EVs. The building electricity demand is set to a constant value of about 7.8 kWh$_{el}$/h, with a yearly total consumption of 68 MWh$_{el}$/yr. Charging of the electric vehicles is set to 100 kWh$_{el}$/day divided in 12 h to 8.3 kWh$_{el}$/h, corresponding to charging about five EVs a day. The charging of the EVs is placed on top of the daily maximum demand of the husehols electricity, because that is what is planned in the brf Viva. Considering the power consumption (and not only the energy consumption) in the building, it would probably be better to shift the charging until after the daily peak demand in household electricity. The household electricity demand is collected from different households in Gothenburg during 2013, the data is provided by Göteborg Energi. A mean value of the 28 households is made, and the total is then scaled to fit the predicted demand of Riksbyggen brf Viva, which is 81 MWh$_{el}$/yr. The total electricity demand of the building for a spring week can be seen in Figure 3.2. The yearly total electricity demand of the building is 185.5 MWh$_{el}$/yr. A representation of the electricity demand for each month can be seen in Appendix A in Figure A.1.

The space heating and hot tap water demand for the building is a mean value of measurements from the year 2013 from 7 different sub-stations in the district heating network in Gothenburg (measurement data provided by Göteborg Energi). This value is then scaled to match the prospective consumption of the building of 309 MWh$_{th}$/yr. Figure 3.3 shows the heat demand data for an example spring week. The total heat demand for each month is displayed in Figure 4.12 in the result section.

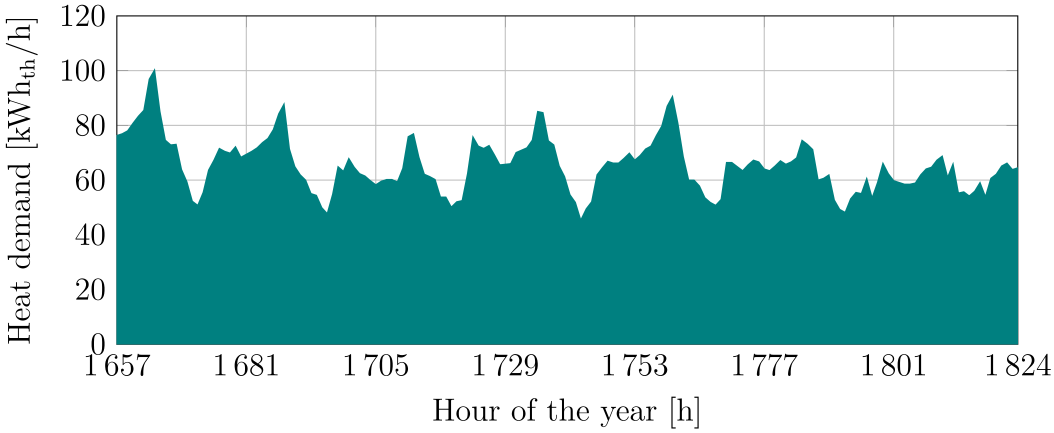


Figure 3.3: The space heating and hot tap water demand during one week in March. The data is a mean value of measurements from the year 2013 from 7 sub-stations in the district heating system. The data was provided by Göteborg Energi.

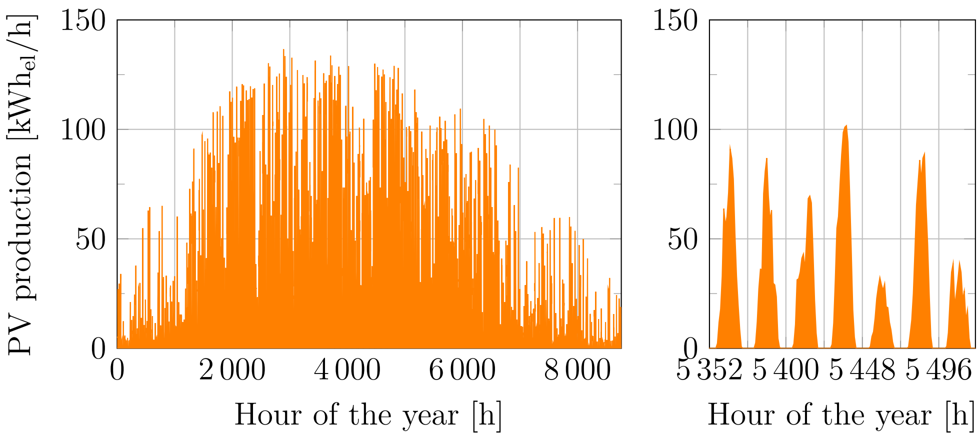
Table 3.1: The COP of the heat pumps in the building, which has been divided by month.

Jan	Feb	Mar	Apr	May	June
2.6	2.7	3.2	3.5	3.9	4.1
July	Aug	Sept	Oct	Nov	Dec
4.2	4.5	4.4	3.9	3.2	2.9

The COP (coefficient of performance) of the heat pumps is collected from the planning of Riksbyggen brf Viva and can be seen in Table 3.1. The COP is set to a mean value for each month.

3.3.2 Solar PV installation

The building is designed to produce more energy than it uses. The energy included is the building electricity and the space heating and tap water demand supplied by heat pumps (and thus no household electricity). This adds up to about 170 MWh_{el}/yr, which then has to be produced by the solar PV installation in the building. The produced PV electricity has been calculated using the free software SAM (National Renewable Energy Laboratory, 2010), and meteorological data for the specific location in Gothenburg, Longitude 57.68 and Latitude 11.98, from the year 2013 from STRÅNG (SMHI, 2015). To be able to produce 170 MWh_{el}/yr the program suggest an installed capacity of about 170 kW. The produced power from the solar PV, for the year 2013, can be seen in Figure 3.4. In Figure 3.4a, the production for the full year is displayed, while in 3.4b a selected summer week is displayed. In Figure 3.4b it is apparent that the PV produces electricity during the day, and nothing during the night.



(a) The full year production. **(b)** A week in July.

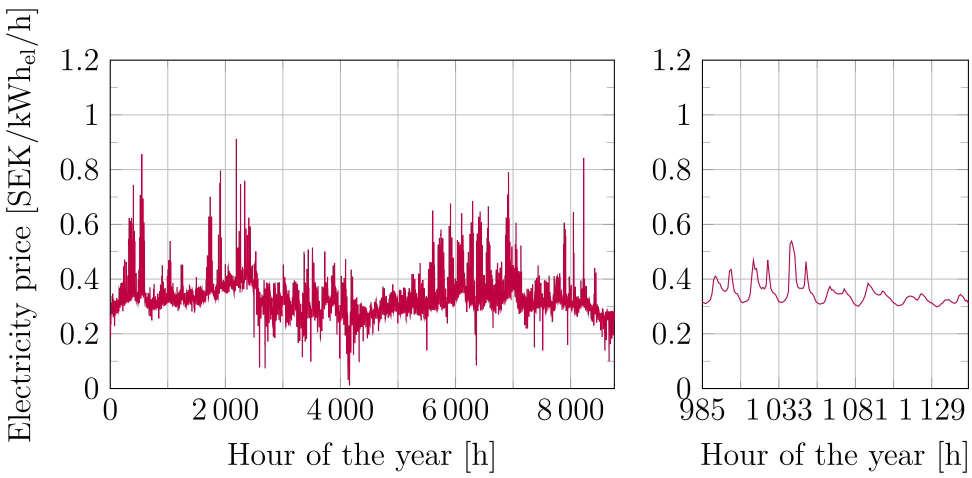
Figure 3.4: Solar PV production during 2013, with solar radiation data from STRÅNG (SMHI, 2015), and electricity production calculated with SAM (National Renewable Energy Laboratory, 2010).

For optimisations with simulated future electricity prices, the energy load curves and the PV production can no longer be correlated to the same year, because the model for the simulated fututre electricity system is based on a typical wheather data year, and not the year 2013. A new curve for the PV production can be obtained from the system production data for the simulated future electricity system, and then scaled to fit the buildings total yearly demand of 170 MWh$_{el}$/yr. This method is assumed to be good enought to get a correlation of the buildings PV production and the prices in the electricity system (as described in Section 3.3.3). The energy load in the building is still 2013 values.

3.3.3 Electricity price

To be able to calculate the running cost for the building each hour, the spot price of electricity and district heating is needed. The historical spot price for the electricity in the southern Sweden for the 2013 is collected from Nord Pool Spot (2015) and can be seen in Figure 3.5. In Figure 3.5a the price for the full year is displayed, while in 3.5b a selected week in February is displayed. In Figure 3.5b it can be seen how the price is fluctuating each day, with a lower price during the night and a higher during the day. It can also be noticed that the price is lower during the weekend.

When modelling, no fixed costs for electricity are included since they would not affect the optimisation, and no power tariffs are calculated for. The end customer electricity price is as described in Table 2.1, 0.61 SEK/kWh$_{el}$ plus the spot price. The revenue for the sold electricity is 0.037 SEK/kWh$_{el}$ plus spot price, when not calculating for the REC. The revenue for the REC is not calculated for because that revenue is the same regardless of whether the electricity is used in the house or sold, and can therefore be treated as a fixed cost.



(a) The price for the full year. **(b)** A week in February.

Figure 3.5: The spot price for electricity in southern Sweden 2013, from Nord Pool Spot (2015). (b) is an example week in February.

For analysis of how the system would be affected by future electricity prices, simulated values for the year 2030 has been used. The prices are based on modelling of the entire European electricity system and different future scenarios with different electricity mixes and subsidy schemes and taxes has been used. Two different future prices has been used in this thesis, one called Green Policy, with a lot of renewable energy, for example 48 TWh (33 %) wind power in Sweden. Wind is price-setting in many hours and the price curve for the Green Policy case is displayed in Figure 3.6. The other case is called Net Metering and is the same scenario as the Green Policy but with strong incentives for solar power leading to high penetration levels and to solar power being on the margin during many hours. Net Metering has in Sweden 31 TWh (21 %) wind and 46 TWh (32 %) solar power, and can be seen as an extreme case regarding the penetration level of the solar power. In both cases all nuclear power is phased out. The price curve for Net Metering can be seen in Figure 3.7. Data for both scenarios is provided by Chalmers, Department of Energy and Environment, Division of Energy Technology.

For a comparison with the different prices, look at Figure 3.8, where all three price curves are presented as price-duration curves. Note that both simulated future prices contains many more hours with very low or zero price, compared to the historic 2013 price, but as well some hours with really high prices, which to a large extent is caused by the phase out of the nuclear power.

3.3.4 Emissions and cost for district heating

The values for the emissions and the running cost for the district heating are provided by Göteborg Energi, and based on their actual production the year 2013. The spot price used in the model for the district heating is the historical marginal (or

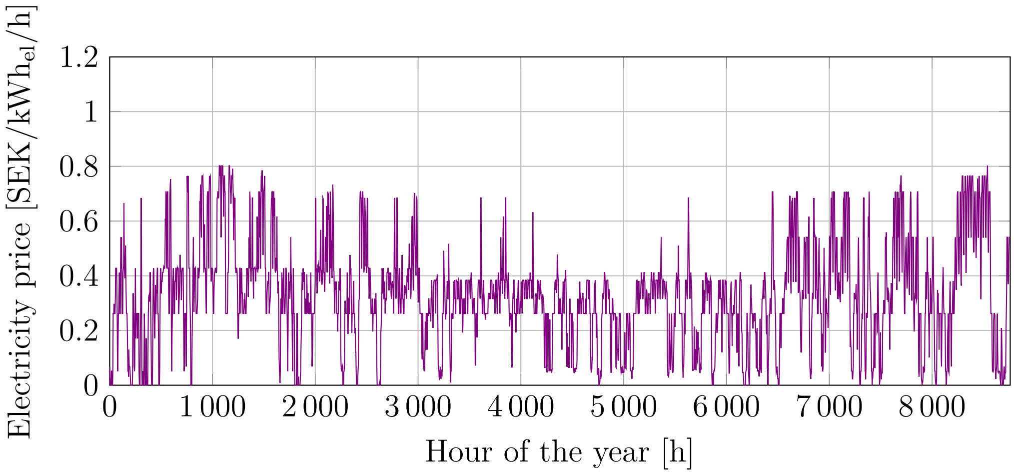


Figure 3.6: Simulated future electricity price in southern Sweden for the year 2030. A scenario called Green Policy, with a lot of renewable power production. The data is provided by Chalmers, Department of Energy and Environment, Division of Energy Technology.

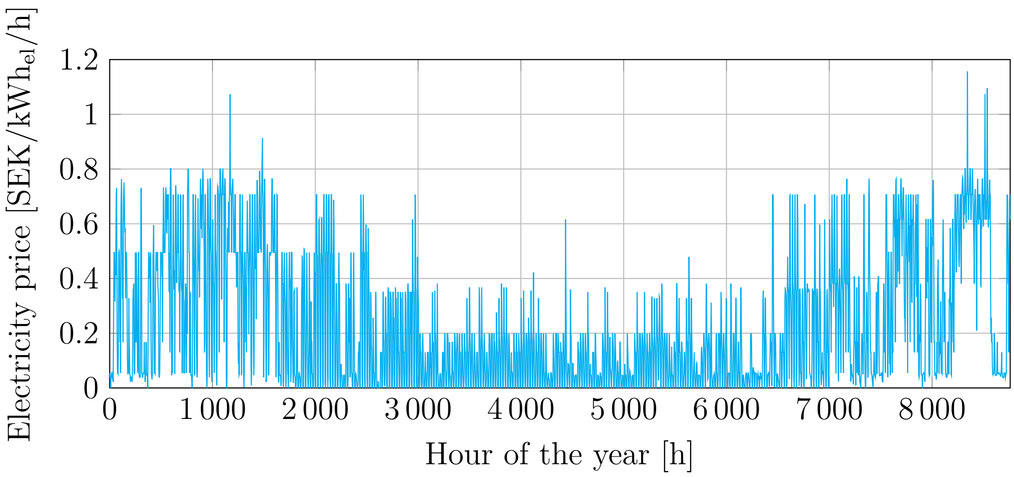


Figure 3.7: Simulated future electricity price in southern Sweden for the year 2030. A scenario called Net Metering, with a lot of subsidies for solar power. The data is provided by Chalmers, Department of Energy and Environment, Division of Energy Technology.

sometimes mean) production cost for each hour, of the district heating system in Gothenburg (data provided by Göteborg Energi through personal communication).

The emissions have been calculated based on the actual production the year 2013, with emission factors from Värmemarknadskommittén (2014) and can be seen in Figure 3.9. The data are provided by Göteborg Energi through personal communication. The marginal emissions are negative at some time-steps due to that the heat is produced in a CHP plant, and therefore also produces electricity. This electricity is then replacing other electricity with higher emissions, and the net marginal emissions are therefore negative. During the summer, the marginal emissions are zero

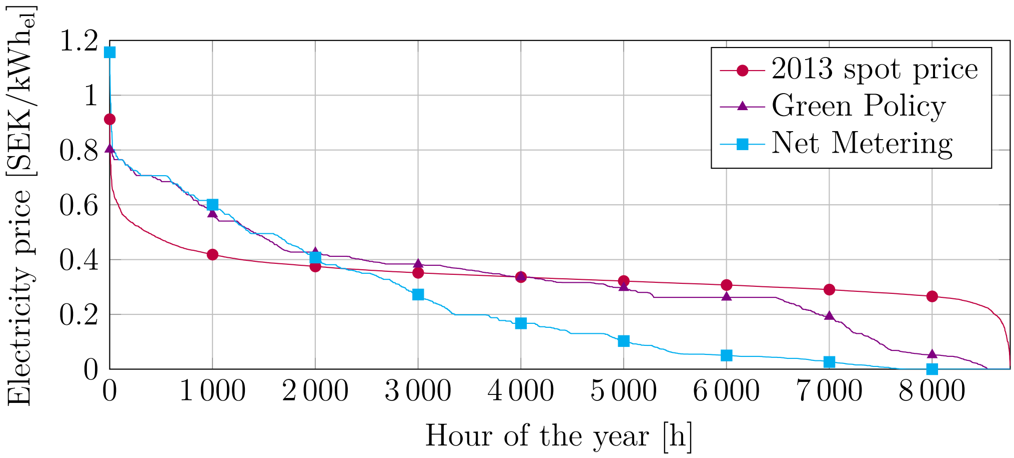


Figure 3.8: A price duration curve for the electricity. The spot price for 2013 can be seen as well as two different simulated future prices for 2030, the Green Policy and the Net Metering.

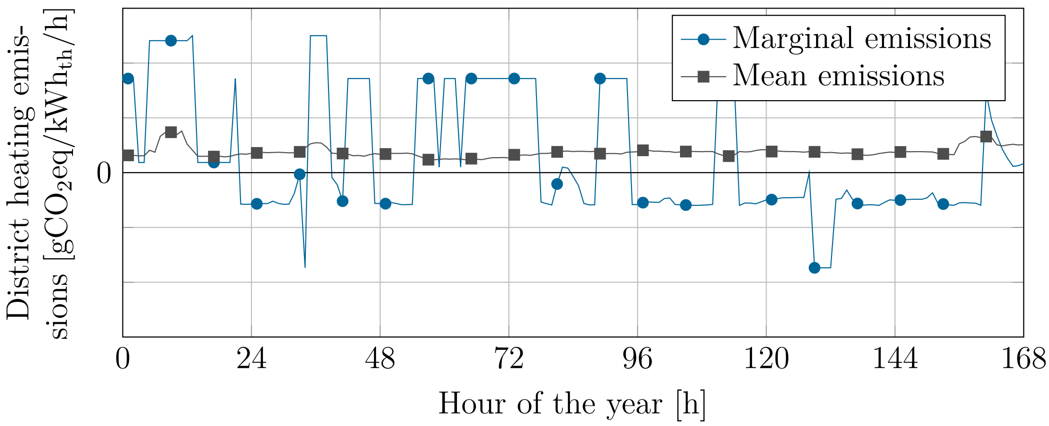


Figure 3.9: The emissions of district heating, calculated from the actual production in the district heating network in Gothenburg, with emission factors from Värmemarknadskommittén (2014). Both marginal and mean values for the emissions are shown.

at most time-steps. Due to that only industrial waste heat and waste incineration CHP plant is in the system, and those produces heat regardless of the demand, and therefore a change in the demand will not change the emissions. The same approach for calculating emissions is used for the electricity in the building. The bought electricity is counted as having a marginal emission of 625 gCO_2eq/kWh_{el}, while the sold electricity (produced by the solar PV in the building) has negative emissions of -625 gCO_2eq/kWh_{el}.

Table 3.2: Mean price and mean value of the daily standard deviations, for different price curves. The mean values for the district heating are not shown due to confidentiality.

Price curve	Daily mean [SEK/kWh]	Daily standard deviation [SEK/kWh]
2013 spot price	0.95	0.042
Green Policy	0.94	0.080
Net Metering	0.84	0.126
DH marginal cost	-	0.060
DH mean cost	-	0.014
HP (2013 spot price)	0.27	0.012

3.3.5 Variations in price

The different prices for the electricity, both the 2013 spot price and the simulated future prices, are fluctuating throughout the year. The mean values of the price and mean values of the daily standard deviation, for the different price curves, for both electricity and district heating, are presented in Table 3.2. For the electricity (including to the heat pumps), a total surcharge of 0.61 $\mathrm{SEK/kWh_{el}}$ is included.

3.3.6 Constraints and assumptions

In the models, limits for the storage capacities and for the heat pumps, as well as power limits for the bought energy can be chosen. Efficiencies for the storage capacities can also be customised to fit the specific purpose. Buy and sell surcharges for the electricity as well as price for the REC can be adjusted. The limitations and adjustment made for this thesis, with respect to Riksbyggen brf Viva is as follows.

The physical limits for both the heat pumps and the district heating connection are set to the maximum hourly heat demand of 119 $\mathrm{kWh_{th}/h}$, since they are both dimensioned to be able to supply the complete thermal demand of a building without storage capacities. An upper limit on the amount of bough or sold electricity is set to 86 $\mathrm{kWh_{el}/h}$ when including the heat pumps and 40 $\mathrm{kWh_{el}/h}$ when the heat pump is not included, which is the same as the maximum hourly electricity demand during the year. For the thermal storage, no losses are assumed, and the charge and discharge capacities are the same as the size of the storage. This means that the storage cannot be charged or discharged fully in shorter time than one hour. The charge and discharge limitations on the thermal storage might seem like a high number when the storage tank is large, but remember that there are limitations on the district heating connection and the heat pump, which means that the storage cannot be charged with higher power than $2 \cdot 119\,\mathrm{kWh_{th}/h}$, and not discharged with higher power than 119 $\mathrm{kWh_{th}/h}$ (maximum demand). The electrical storage is assumed to have 7 % losses while charging and 7 % losses while discharging, which corresponds to an overall efficiency of 86 %. The charge and discharge limits are set to 1C, i.e.

charging or discharging fully in one hour. The buy and sell surcharge that are added to the spot price for electricity are set to 0.61 SEK/kWh_{el} and 0.037 SEK/kWh_{el} respectively, as described in Table 2.1. The sell surcharge is, however, without the revenue for the REC since it can be collected regardless of if the electricity is used directly in the building or sold.

4
Results

The modelling was performed in three steps, and the results will be presented accordingly. First the results form the electricity model will be presented, including electricity production from the solar PV installation, electricity storage and buying electricity on spot price. Some outlook on how the system will work with different future electricity prices will also be shown. A separate investigation on the thermal system in the building has also been made and the results will be presented. The thermal system includes availability to fulfil the heat demand with either heat pumps or with district heating. A thermal storage was also included, and both district heating and electricity could be bought on spot price. In the end of this chapter, the results from the optimisation of the combined heat and electricity system model will be presented.

4.1 The electricity system

Optimising the operational strategies of the building's electricity system was done by minimising the running cost according to Equation 3.1. No electricity to the heat pumps were included in the electricity model.

4.1.1 Storage reduces the dependency on electricity from the grid

An electrical storage together with solar PV reduces the dependency on electricity from the grid, and makes the building more self-sufficient on electricity. The share of the hours of the year the building is self-sufficient on electricity, i.e. does not buy electricity from the grid, as a function of storage size can be seen in Figure 4.1. The share of the year that the building is self-sufficient increases with storage capacity up until a storage size of about 350 $\mathrm{kWh_{el}}$. Note that the total electricity demand (excluding the heat pumps) is 185.5 $\mathrm{MWh_{el}}$/yr while the total produced PV electricity is 170 $\mathrm{MWh_{el}}$/yr, and thus, 100 % self-sufficiency will never be reached.

The number of hours that the building needs to buy, or sell, electricity to/from the grid for different storage sizes are presented in a duration diagram, i.e. a diagram with the values sorted in descending order, in Figure 4.2. In the figure, the positive parts are bought electricity while the negative parts are sold electricity. Note the power limit on electricity that is set to the maximum hourly average demand which

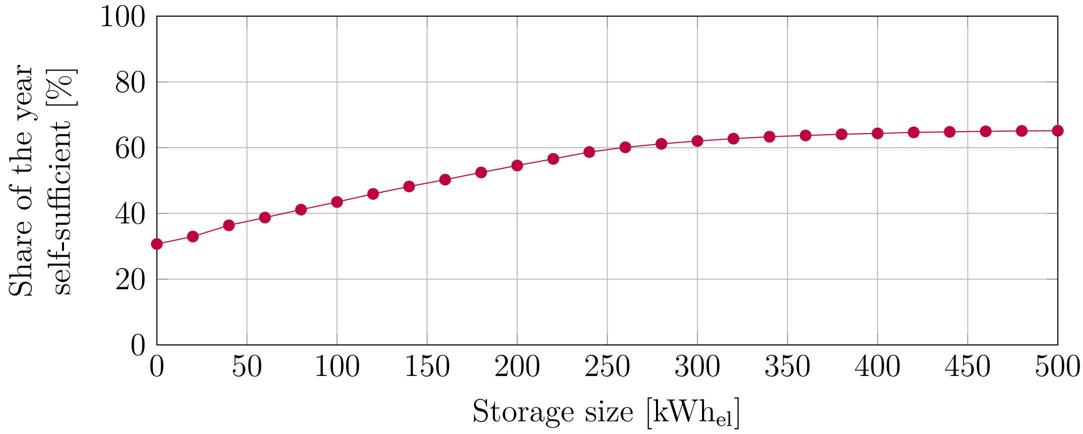
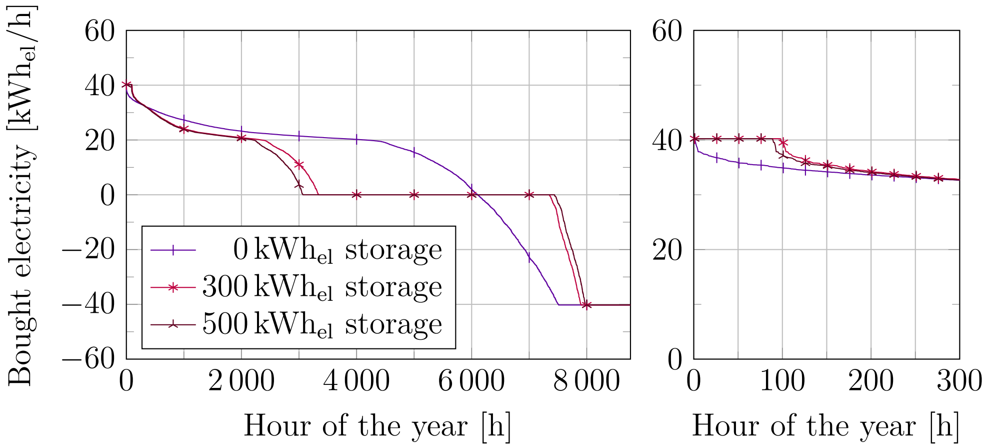


Figure 4.1: Share of the hours of the year that the building is self-sufficient on electricity, without using the heat pumps. Note that the total electricity demand (excluding the heat pumps) is 185.5 MWh$_{el}$/yr while the total produced PV electricity is 170 MWh$_{el}$/yr, and thus 100 % self-sufficiency will never be reached.

is 40 kW$_{el}$. In Figure 4.2a, it can be seen that without storage, electricity needs to be bought about 6 000 h/yr, while with a storage capacity of 300 kWh$_{el}$, electricity only needs to be bought about 3 000 h/yr. In Figure 4.2b, a zoom in of the leftmost part is displayed. There it can be seen that with a storage capacity of 300 kWh$_{el}$, more electricity than is consumed in that specific hour is bought about 200 h/yr, and saved in the storage for later use. These hours where more electricity than consumed is bought are due to low spot price. As seen in Figure 4.2b these hours are few and hence the spot price does not significantly affect the value of an electrical storage when solar PVs are in the system. Noticeable in the figure is also that a storage size of 500 kWh$_{el}$ does not significantly affect the amount of bought and sold electricity compared to a storage size of 300 kWh$_{el}$, which was also apparent in the figure with the share of the year self-sufficient on electricity, Figure 4.1.

4.1.2 The electrical storage is used year round

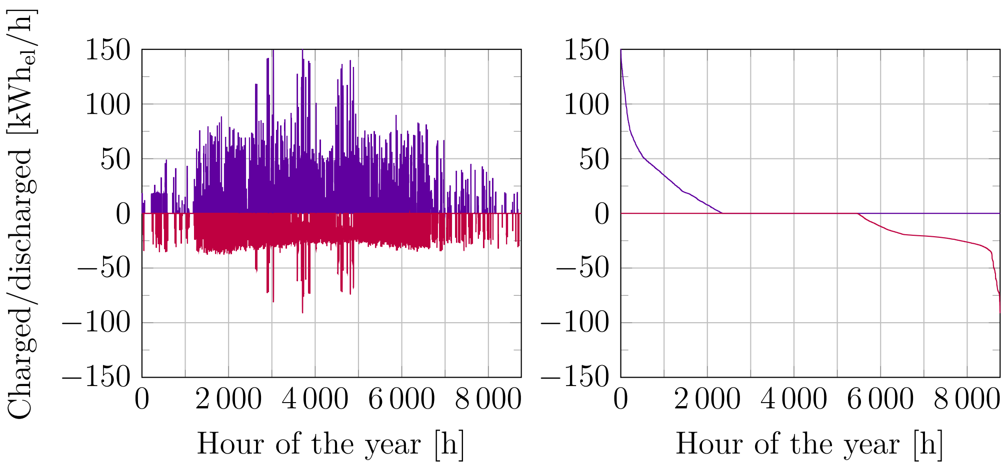
Looking at Figure 4.3, it can be observed how the electrical storage is utilised. The figure shows how the storage is charged (positive part) and discharged (negative part) for a storage size of 300 kWh$_{el}$ and with the spot price on electricity for 2013. In Figure 4.3a the data are displayed in chronological order, while in Figure 4.3b the data are displayed in a duration curve. It can be noticed that the storage is used year round, although mostly during the summer when the solar PV produces most (se Figure 3.4). The total number of hours that the storage is charging is about 27 % of the year, and discharging 37 % of the year.



(a) A full year duration curve.

(b) A zoom of the left most part.

Figure 4.2: Amount of bought and sold electricity, in kWh$_{el}$/h, during one year with the spot price of 2013. The values are presented in a duration curve, i.e. the values sorted in descending order, where the positive part is bought electricity and the negative part is sold electricity. Three different graphs for different storage sizes are shown. Note the power limit of 40 kW$_{el}$ in both directions.



(a) In chronological order.

(b) A duration curve.

Figure 4.3: Amount of electricity charged or discharged from the electric storage, with a storage size of 300 kWh$_{el}$ and with the spot price of 2013. The positive parts of the graphs are charging the electricity storage, and the negative parts are discharging.

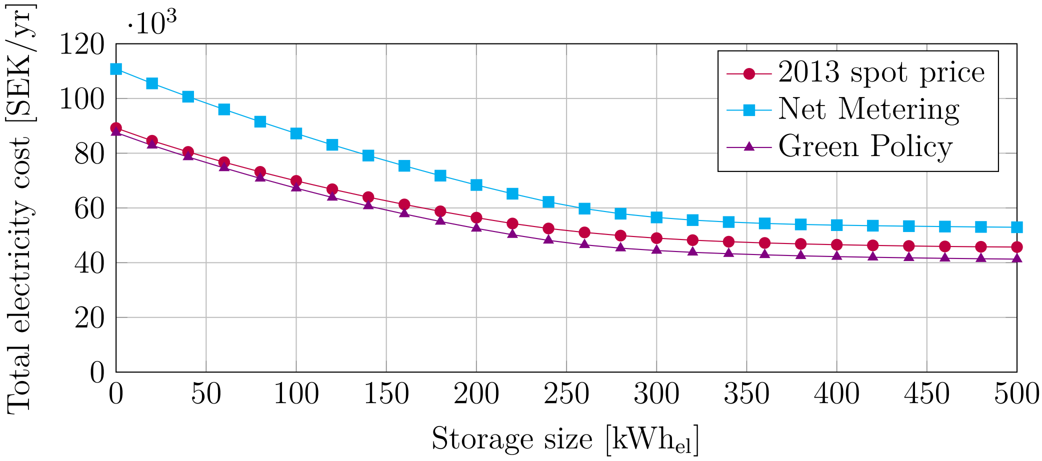


Figure 4.4: Total variable electricity cost per year for different storage sizes. The optimisation has been made with 2013 spot price as well as for future simulated prices for the year 2030. Note that no electricity to heat pumps are included and no fixed costs or power tariffs are included.

4.1.3 The running cost decreases with increased storage size

The total running cost per year decreases with increased electrical storage size, up to a storage size of about 300 kWh_{el}. This decrease in running cost is obtained with both the spot price of 2013, and with simulated future electricity prices of 2030, the Net Metering case and the Green Policy. The running costs for all three data sets are displayed in Figure 4.4 as a function of storage size. The cost reduction is diminishing, this means that the first kWh storage capacity is more worth than the 100th.

With a storage capacity of 300 kWh_{el}, with the spot price of 2013, the running cost can be reduced with 45 % compared to without storage. In Figure 4.4 it is apparent that the cost reduction with storage is slightly larger in the Net Metering case, compared to the other cases. This is because that for small storage sizes, a lot of solar electricity needs to be sold, and with the Net Metering scenario, electricity prices are often close to zero the hours when the sun is shining, and it is therefore more valuable with a storage. Note that no fixed costs or power tariffs are included here. The slightly larger reduction with the simulated future prices can also be because of the price is fluctuating more compared to the spot price of 2013, and these fluctuations can then be utilised in a favourable way with the storage, by buying more electricity during the cheaper hours, and avoiding the more expensive hours.

This difference in cost between the spot price of 2013 and the Net Metering case can be viewed in a duration curve in Figure 4.5, where the electricity cost per hour for a storage size of 300 kWh_{el} is displayed. With a storage size of 300 kWh_{el} and with the spot price of 2013, 27 % of the expenses are covered by the revenues, while for the Net Metering case only 5 % of the expenses are covered by the revenues. Note that no revenue for electricity certificates has been calculated for.

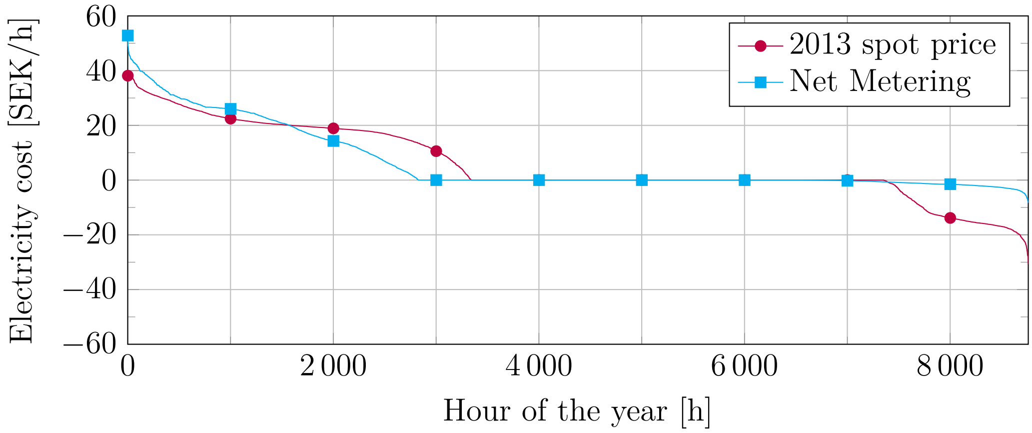


Figure 4.5: Electricity cost per hour with a storage size of 300 $\mathrm{kWh_{el}}$ presented in a duration curve, with the spot price of 2013 and with simulated future prices of the Net Metering case. Note that the expenses are in the same magnitude for the two cases, while the revenues are much smaller for the Net Metering case.

4.2 The thermal system

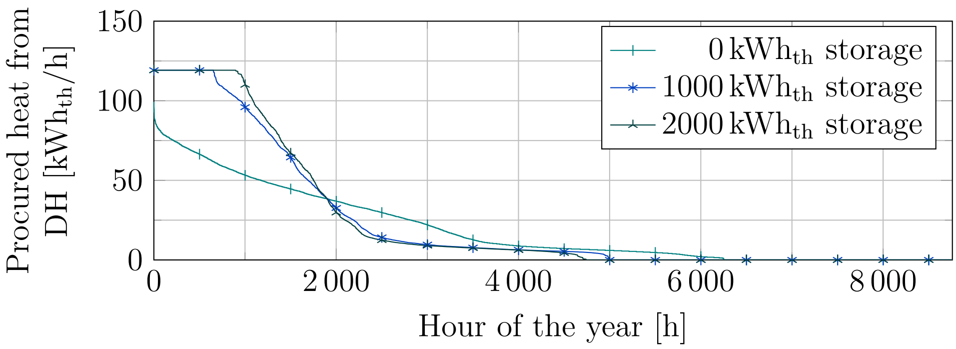
Minimising the running cost of the thermal system was done according to Equation 3.2 to be able to optimise the operational strategies of the building. The optimisation used the thermal storage as well as the price shifting in the district heating system in correlation to the fluctuations in the electricity spot price of 2013.

4.2.1 Storage reduces the dependencies on the grids

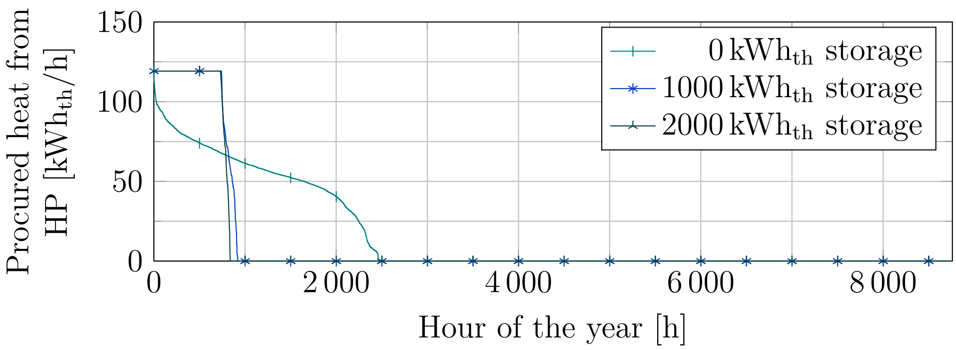
With a thermal storage in the building the number of hours that both district heating and electricity to the heat pumps needs to be bought are reduced, although that the total amount of procured heat is the same. This mean that more heat per hour is procured those fewer hours. The amount of procured heat from district heating and heat pumps are shown in Figure 4.6a and 4.6b respectively, the district heating is bought with marginal pricing. In the figure, it can be noticed that the number of hours that heat is procured are about the same for a storage size of 1 000 $\mathrm{kWh_{th}}$ as for a storage size of 2 000 $\mathrm{kWh_{th}}$, and thus, the larger storage size does not affect the result in the same extent as the smaller does.

4.2.2 The thermal storage is used almost constantly

The thermal storage in the building is used almost constantly, but with very small volumes charged or discharged during the summer. This is because no losses are included, and therefor even the smallest price change activates the storage. The utilisation of the thermal storage, with a storage capacity of 1 000 $\mathrm{kWh_{th}}$ and with the marginal pricing of district heating, can be seen in Figure 4.7, both in chronological



(a) Procured heat from district heating.



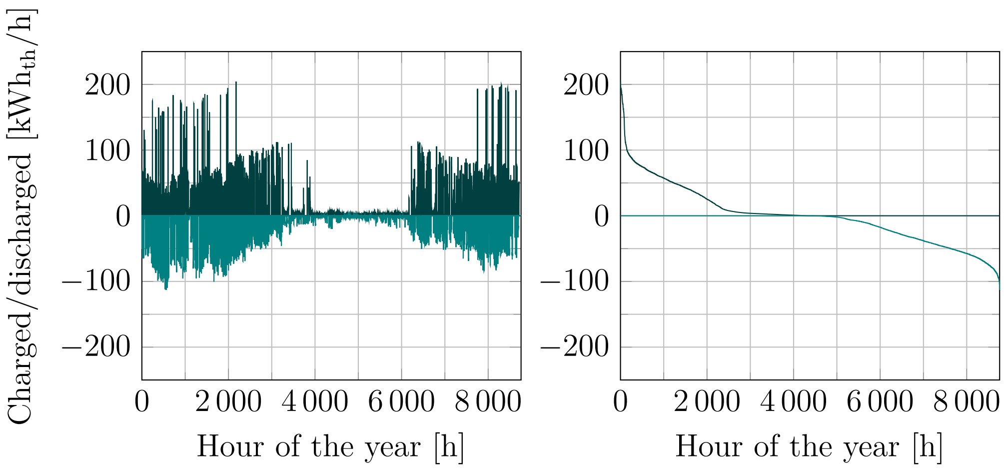
(b) Procured heat from the heat pumps.

Figure 4.6: (a) shows the amount of procured heat from district heating, while (b) shows the procured heat from heat pumps. Both graphs shows data from three different sizes of the thermal storage. With a storage, heat is procured fewer hours of the year, but instead more heat is procured each of those hours.

order (4.7a) and in a duration graph (4.7b). The positive parts of the graphs are charging, while the negative parts are discharging. In the figure it can be noticed that the storage are charged at its maximum with both district heating and the heat pumps very few hours of the year, and most of the time it is charged with less than 100 kWh$_{th}$/h. It can also be noticed that the storage is sparsely used during the summer. This is due to constant low district heating cost, making the storage unnecessary. Recall that no PV electricity is included in this part of the model.

4.2.3 The share of district heating increases with storage size

The share of the heat supplied by district heating is slightly increasing with increased thermal storage capacity. This can be viewed in Figure 4.8, for both marginal and mean pricing for district heating. The electricity to the heat pumps is always bought with the spot price of 2013. The values in the figure are the total energy bought



(a) Data in chronological order.

(b) A duration curve.

Figure 4.7: Amount of heat charged or discharged from the thermal storage, with a storage size of 1 000 kWh$_{th}$ and with the marginal pricing of district heating. The positive parts of the graphs are charging the thermal storage and the negative parts are discharging. In (a) the data are presented in descending order, while in (b) the same data is presented in a duration graph.

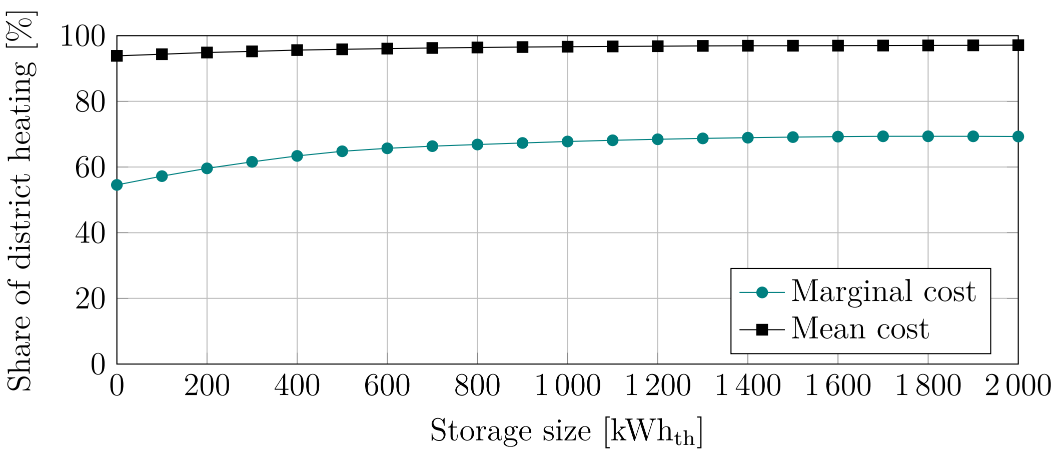


Figure 4.8: The share of district heating supplying the heat demand in the building during one year, for different storage sizes. The remaining heat is supplied by heat pumps. The lower graph is with marginal pricing on district heating, while the upper graph is with mean pricing.

from district heating compared to the total heat demand during one year. The share of district heating, with the marginal pricing, is increasing up to a storage size of about 1 000 kWh_{th}. The increase is due to that the marginal district heating cost is fluctuating more than the price for heat from heat pumps (see Table 3.2), and when the storage size increases, the hours with low district heating prices can be utilised to a larger extent. When running the optimisation with the mean pricing on district heating, the share of district heating is always above 90 %, due to constant low district heating costs.

4.2.4 The running cost decreases when using both district heating and heat pumps

The total running cost per year for the thermal system decreases when using a combination of district heating and heat pumps compared to only using one of the technologies. This decrease can be seen in Figure 4.9 where the running cost is displayed as a function of storage size. In the figure the running cost with marginal district heating price as well as for mean district heating price are shown. The running cost for the thermal system with only heat pumps (and no district heating) is also shown, as well as the opposite with only district heating with marginal pricing and no heat pumps. All cases are using the spot price of the year 2013 on electricity for the heat pumps, and keep in mind that no electricity from the solar PV is included in the thermal system. In the figure it can be seen that using both district heating and heat pumps together is favourable compared to using only one of them, regardless of pricing and storage size. With marginal pricing on district heating, and with both district heating and heat pumps available, a cost reduction of 12 % can be obtained with a thermal storage of 1 000 kWh_{th}. If looking at Figure 4.8, it can be seen that with the mean price of district heating, the district heating is supplying almost all heat to the building. This indicates that the curve in Figure 4.9 with both techniques and mean price on district heating, is in fact an only district heating curve, with mean pricing.

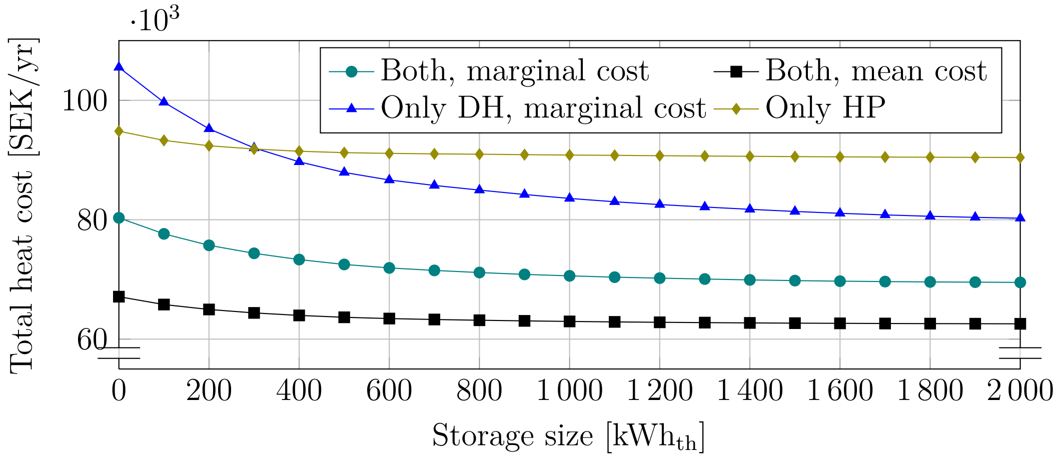


Figure 4.9: Total heat cost per year for different storage sizes. Note the scale on the y axis, starting on 60 000 SEK/yr. The two lower graphs are for the case with both district heating and heat pumps, but with different pricing on the district heating. The two upper graphs are with either heat pumps or district heating, the district heating is with marginal pricing.

4.3 Optimising both heat and electricity

Running the optimisation on the combined heat and electricity system gives possibilities to investigate how the storage capacities are used together and how the produced PV electricity is used together with the heat pumps and the thermal storage. The optimisation for the combined heat and electricity system is made with the spot price of 2013 for the electricity, and with the marginal pricing of district heating.

4.3.1 The electricity and thermal storage complement each other

The total running cost for the combined heat and electricity system is reduced when including only a thermal storage, or only an electrical storage, as presented in Table 4.1. The running cost is, however, reduced even more when combining the two storage capacities in the building. With an electrical storage size of 300 kWh_{el} and a thermal storage size of 1 000 kWh_{th}, the total running cost can be reduced with 24 % compared to without storage. Recall that no fixed costs are included and no power tariffs.

The total running cost without storage capacities and without district heating is 161 500 SEK/yr, and thus including district heating reduces the cost with 7 %. The cost will then be even lower when introducing storage capacities as described above.

When both storage capacities are included in the energy system, the electrical storage is used mostly during the summer and the thermal storage is used mostly during the winter, as seen in Figure 4.10a and 4.10b respectively. During spring and

Table 4.1: Total running cost per year for different combinations of storage sizes.

Electrical storage size	[kWh_{el}]	0	0	300	300
Thermal storage size	[kWh_{th}]	0	1 000	0	1 000
Total cost	[SEK/yr]	150 000	135 200	124 300	113 500
Cost reduction		-	9.9 %	17 %	24 %

Table 4.2: The amount of energy that is charged to the electricity and thermal storage respectively, for different combinations of storage sizes, during one year. The total losses in the electricity storage are also shown.

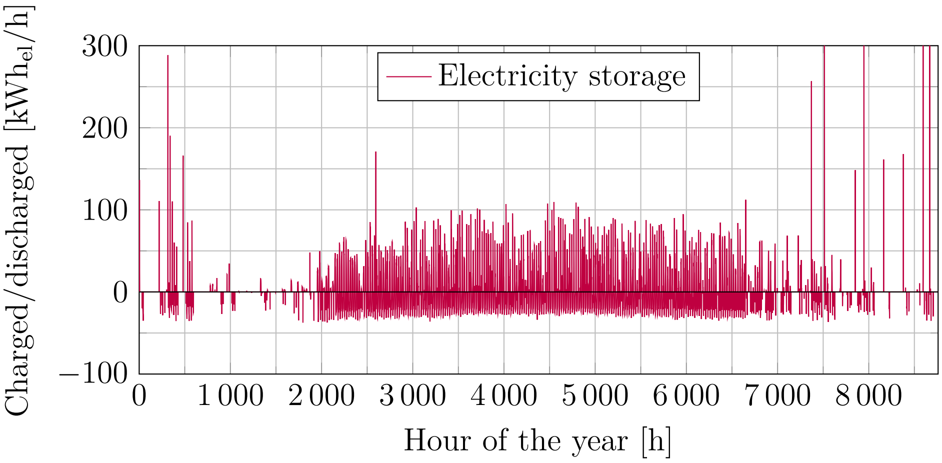
Electrical storage size	[kWh_{el}]	0	300	300
Thermal storage size	[kWh_{th}]	1 000	0	1 000
Charged electricity	[kWh_{el}/yr]	0	66 430	58 500
Electricity losses	[kWh_{el}/yr]	0	9 020	7 916
Charged heat	[kWh_{th}/yr]	169 700	0	164 400

autumn, however, both storage capacities are utilised. Both graphs are with an electrical storage of 300 kWh_{el} and a thermal storage of 1000 kWh_{th}. Compared to the optimisation on only the electricity system, the electrical storage is used during a smaller part of the year. This is because a share of the excess electricity can now be used as heat through the heat pump, instead of saved in the electricity storage where there are losses.

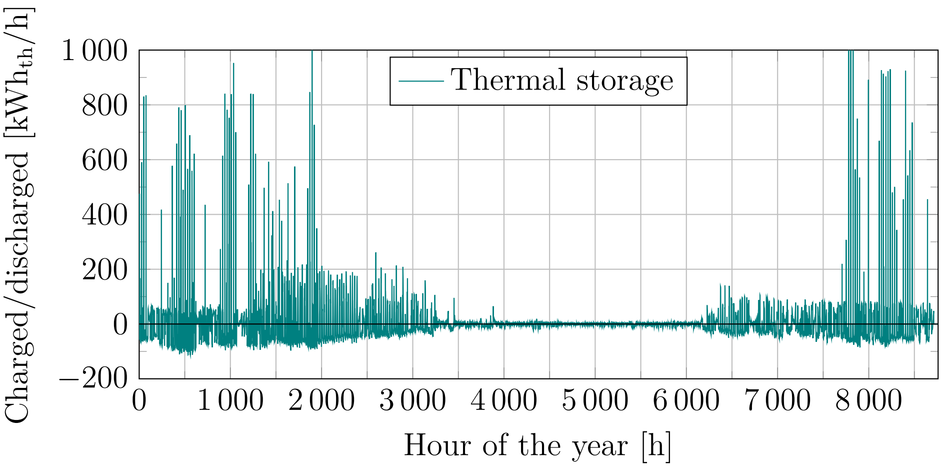
When investigating the same case, with both electricity and thermal storage, it can be calculated that about half (53 %) of the heat load in the building is passing through the thermal storage. In the same way about 22 % of the electricity load (including the electricity use in the heat pumps) of the building is passing the electrical storage. The amount of charged heat or electricity to the storages for different cases are presented in Table 4.2, in kWh/yr. In the same table, the amount of losses in the electricity storage are also shown. It can be noticed in the table that when having both storage capacities, the amount of charged electricity and heat is only slightly reduced compared to when only having one of the storage capacities. This indicates that the storages are complementing each other.

4.3.2 Storage decreases the amount of sold PV electricity

With no storage at all, produced PV electricity needs to be sold almost all months of the year, as seen in Figure 4.11a. The figure shows how much of the produced solar electricity that is used in the building compared to what needs to be sold. The entire bar is the produced electricity each month, the lower, darker part represents what is used in the building and the upper, lighter part represents what is sold. When introducing a thermal storage, as displayed in Figure 4.11b, the largest difference can be seen in March, where less electricity need to be sold. This is due to



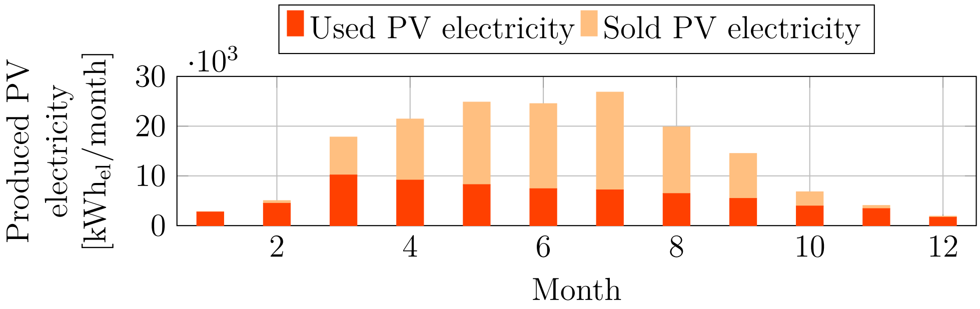
(a) Charged/discharged from the electricity storage.



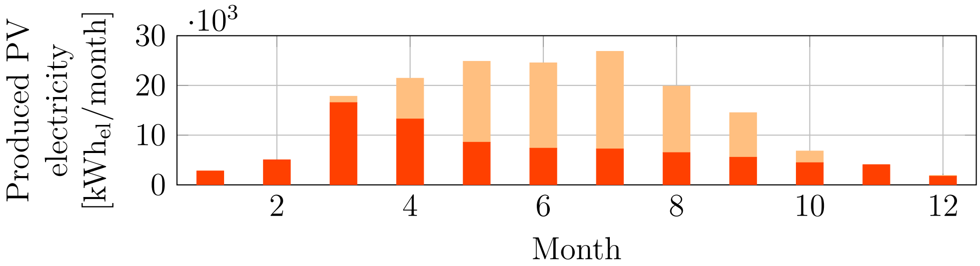
(b) Charged/discharged from the thermal storage.

Figure 4.10: Amount of energy charged or discharged to/from the electrical (a) and thermal (b) storage respectively. The data is from the optimisation of both the heat and electricity system with an electrical storage size of 300 kWh_{el} and a thermal storage size of 1 000 kWh_{th} and with the spot price on electricity from 2013 and marginal pricing on district heating. The positive parts of the graphs are charging the storage capacities, and the negative parts are discharging. Note the different scales on the y axes.

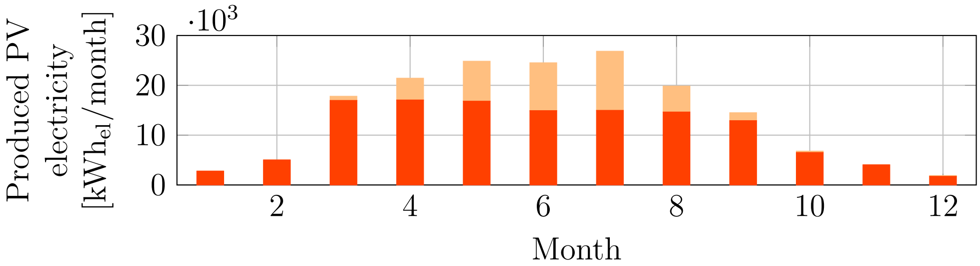
high solar radiation in combination with high heating demand, and thus, the heat pumps together with the thermal storage can be used to handle the excess electricity. When instead introducing only an electrical storage, as displayed in 4.11c, the share of produced electricity that can be used in the building is increased almost all months, compared to without storage. With both electricity and thermal storage, as displayed in 4.11d, almost all produced electricity can be used in the building during March, April and September, months with high PV electricity production and in the same time heat demand. This makes use of the electrical and thermal storage in combination.



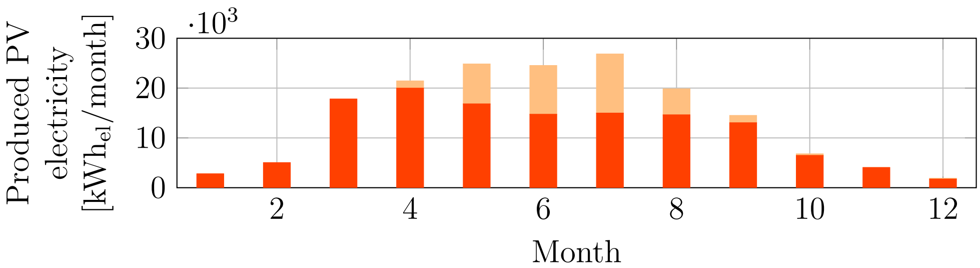
(a) No storage capacities.



(b) A thermal storage of 1 000 kWh$_{th}$, no electricity storage.

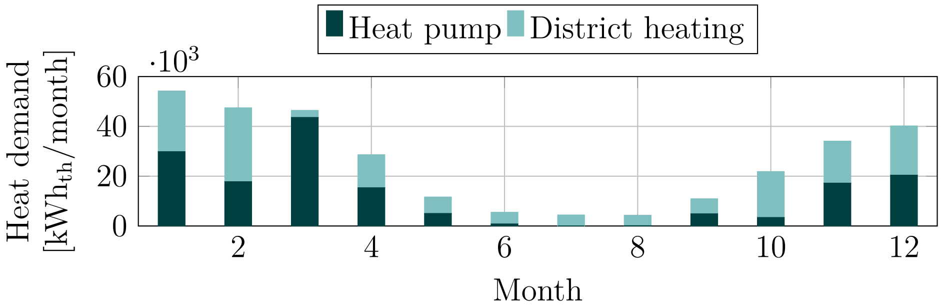


(c) An electrical storage of 300 kWh$_{el}$, no thermal storage.

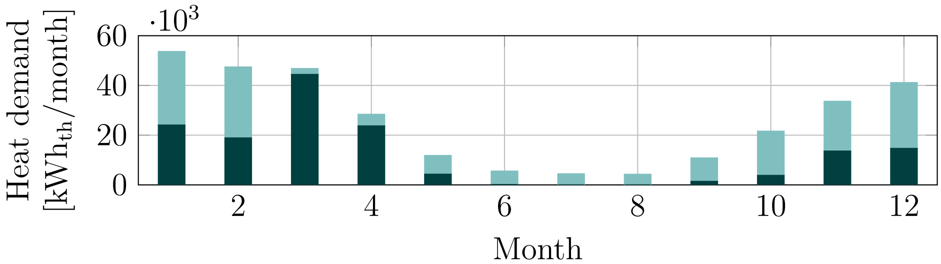


(d) A thermal storage of 1 000 kWh$_{th}$ and an electrical storage of 300 kWh$_{el}$.

Figure 4.11: Share of the produced PV electricity that is used in the building compare to what is sold each month. The entire bar is the total produced PV electricity for each month, the lower darker part is the PV electricity used in the building and the upper lighter part is the sold PV electricity.



(a) No storage capacities.



(b) A thermal storage of 1 000 kWh$_{th}$, no electrical storage.

Figure 4.12: The entire bar shows the total heat demand for each month. The lower darker part represents the heat supplied by the heat pumps while the upper lighter part is the heat supplied by district heating.

The utilisation of the heat pump together with the thermal storage in the spring can be seen in Figure 4.12, where the different share of the heat demand supplied by district heating or heat pumps for each month is shown. The entire bar is the heat demand for each month, the lower, darker part represents the heat supplied by heat pumps, while the upper, lighter part is the heat supplied by district heating. In Figure 4.12a no storage capacities are in the system while in Figure 4.12b, a thermal storage of 1 000 kWh$_{th}$ is included. It can be seen that the heat pump is used more in April when having a thermal storage to be able to handle the excess electricity produced by the solar PV. Another observation that can be made from these graphs is that the heat pump and the district heating is used alternately throughout the year except during the summer (when the marginal district heating cost is so low that district heating is always preferred to heat pumps). Graphs for all four cases (no storage, only thermal, only electricity or combined storage capacities) are displayed in Appendix A in figure A.2.

With both a thermal and an electrical storage in the system, the building can be self-sufficient on electricity 59 % of the hours of the year, while without storage, the building is only self-sufficient on electricity 29 % of the hours of the year. The share of the hours of the year that the building is self-sufficient on electricity for different combinations of storage sizes are presented in Table 4.3. In the same table values of the share of the year that the building is self-sufficient on energy, i.e. not even needing to buy district heating, are also shown.

Table 4.3: Share of the year self-sufficient on energy and electricity respectively for different combinations of storage sizes.

Electrical storage size	[kWh_{el}]	0	0	300	300
Thermal storage size	[kWh_{th}]	0	1 000	0	1 000
Self-sufficient energy		10 %	15 %	14 %	26 %
Self-sufficient electricity		29 %	31 %	57 %	59 %

Table 4.4: Total emissions per year for different storage sizes, calculated based on the actual production in the district heating system in Gothenburg 2013, with emission factors as agreed by Värmemarknadskommittén (2014).

Electrical storage size	[kWh_{el}]	0	0	300	300
Thermal storage size	[kWh_{th}]	0	1 000	0	1 000
Emissions electricity	[kg CO_2/yr]	42 090	40 120	47 170	42 430
Emissions district heating	[kg CO_2/yr]	3 128	534	2 779	86
Total emissions	[kg CO_2/yr]	45 210	40 650	49 950	42 520

4.3.3 Environmental impact

For the district heating in Gothenburg 2013, data for the environmental impact for every hour has been provided by Göteborg Energi. The marginal values for the amount of CO_2eq emissions has been calculated with respect to the values from the Swedish Heat Market Committee (Värmemarknadskommittén, 2014), and combined with the production in the district heating system in Gothenburg 2013. When calculating with emission values for the district heating, the electricity is assumed to have constant marginal emissions of 625 gCO_2eq/kWh_{el}, which is used for the bought electricity and represents avoided emissions for the sold electricity. With these calculations, the yearly emissions for different combinations of storage sizes can be seen in Table 4.4. Note that no optimisation has been done on the environmental impact, but on the running cost, the emissions have been calculated afterwards.

The emissions for the electricity are higher for the system with the electricity storage, than without any storage. This is due to the electrical storage allows for buying more electricity when the spot price is low and using it with the heat pumps later, and in the same time, constant emissions for the electricity are used which are mostly higher than the emissions from district heating. That means that the emissions from electricity are direct proportional to the amount of bought electricity. The emissions from district heating are, however, reduced when introducing storage capacities, this indicates that hourly values of the marginal production cost and the marginal emissions of the district heating system are correlated.

5
Discussion

Most of the input data for the model was collected as historical data from the year 2013. Basing all input data on the same year makes weather data, weekdays, and other dependencies consistent. The price data for the district heating corresponds to the actual marginal production cost, but this might not easily be transferred to a spot price to the customers (as it is used in this thesis). Even if the large cost fluctuations in the district heating network can be utilised by the customers to lower their costs, it might be difficult for the district heating company to implement such a price model. If the price is fluctuating too much, it creates an uncertainty of the total cost for the customers, which might not be easily accepted. A more widely accepted spot price for the district heating would probably be some combination of the mean and marginal production cost, since the marginal production cost is fluctuating too much. Compared to the electricity system, the district heating system in Gothenburg is very small, and the steps between different district heating plants is therefore larger than the steps between different power plants in the electricity system. The benefits from using the marginal production cost can however be used by Göteborg Energi if they were able to control the heating system in the building, and still let the customer have a fixed, or at least less variable, price.

For the heating system or the combined heat and electricity system, no optimisations with the simulated future electricity prices could be made due to that the data was not synced with the district heating data. The simulated future electricity prices are based on a typical weather year, and could not be transferred to the 2013 weather. The data would in that case not be consistent with solar radiation, wind power production, outside temperature etc. When optimising only the electricity system it was assumed that the electricity demand in the building was not significantly affected by the weather and thus optimisations with the simulated future electricity prices could be done together with the electricity demand data for 2013. The PV production was in these cases, however, taken from the simulated future data to be able to get the correct selling price for electricity on hours with a lot of solar power production. With only the electricity system, the total running cost for one year was not significantly different between the different scenarios, although a slight increase of the value with a storage could be seen in the Net Metering case. This would probably also be the case for the combined optimisation of heat and electricity. Since the electricity price will most likely be more fluctuating in the future, and also hour with zero price could occur, the value of having both an electrical storage and heat pumps together with a thermal storage will increase.

Compared to the study from UK (Vytelingum et al., 2010), where 13 % of the customer's electricity bill could be saved with a storage capacity of only 4 kWh_{el}, this model does not come to the same saving possibilities. In this study, with a storage capacity of 40 kWh_{el}, about 10 % of the running costs can be saved. This indicates that the price fluctuations are smaller, or that a larger share of electricity cost is fixed (compared to what is variable) in Sweden compared to in the UK. Another reason might be the power tariffs or the fixed costs, that is not calculated for in this thesis.

When calculating the environmental impact in this thesis, the marginal approach was used for emissions from district heating and electricity. This is only one way of calculating the emissions, and the results should only be seen as a guidance. Moreover, the marginal emissions for the electricity was set to a constant high value. If the mean approach for the emission calculations had been used, a lower value for the emissions from the electricity had been achieved than for the marginal case. For the district heating on the other hand, a higher value for the emissions would be achieved if calculating with mean values, because of the sometimes negative marginal emissions that is lowering the total emissions in the marginal case. Since the electricity system is large and connected to many other systems, it is difficult to find a correct answer to what the change in emissions would be if the demand was changed. In the district heating system, however, the numbers for the emissions are better known, since the system is smaller and closed. Still, the emissions factors for the different plants are decided by the Swedish Heat Market Committee (Värmemarknadskommittén, 2014) and not calculated for the specific plants in the Gothenburg system. The actual production in the Gothenburg system has been used together with these numbers. To assume constant marginal emission on the electricity today might be reasonable, but if calculations on the emission would have been made with the simulated future electricity prices, it would probably not have been correct. A counter-argument is that if there are hour where the price is zero, it means that the production on the margin has a zero running cost, most probably wind or solar, and there will also be an excess of that electricity. The marginal emissions for those hours would be calculated as zero.

No power tariffs were included in the model, and this is what probably would have had the highest effect on the outcome. The power tariffs were not included due to complexity in the model and due to the difference in how they are calculated between different companies. A fixed power limit were, however, set on both the electricity (for sold as well as bought) and the district heating. When including storage capacities for both heat and electricity in the building, it should not be a big effort to lower the maximum power, if that is most profitable, in the building. How large/small the maximum power should be in order to minimise the cost needs further investigation. The possible savings on the power tariff could increase the value of an energy storage.

In the model the heat pump can be used on part load, and there are no restrictions on how often the heating system in the building should change between the heat pumps and the district heating. This could beneficially be implemented in the model because the heat pumps will be more efficient if used on full load and not start and stop often. As seen in Figure 4.6b, when having a storage, the heat pumps are almost always used either on full load or not at all, but it might still be that the heat pumps and the district heating is alternating from hour to hour.

Based on a simple investment calculation on the electricity system, counting that the storage should be payed down in ten years and with a discount rate on 5 %, and a storage size of 300 $\mathrm{kWh_{el}}$, the investment of a storage would need to be lower than 1040 SEK/$\mathrm{kWh_{el}}$ to be profitable. Making the same type of investment calculation on the thermal system, for a storage size of 1 000 $\mathrm{kWh_{th}}$ the investment cost need to be lower than 80 SEK/$\mathrm{kWh_{th}}$. If instead looking at the optimisation of both heat and electricity together, and counting the electrical storage of 300 $\mathrm{kWh_{el}}$ as the main savings, and the thermal storage of 1 000 $\mathrm{kWh_{th}}$ introducing the complimentary savings, the investment cost needs to be lower than 660 SEK/$\mathrm{kWh_{el}}$ for the electrical storage and lower than 80 SEK/$\mathrm{kWh_{th}}$ for the thermal storage. Tesla's Powerwall bettery for daily cycle applications costs about 3 600 SEK/$\mathrm{kWh_{el}}$ (Tesla Motors, 2015). This indicates that it is not yet profitable to install a battery with today's prices in Sweden. If including the possible savings with a lowered power tariff, the investment calculation might be more favourable, but it will probably still not be enough. The investment cost for a hot water storage tank is most likely lower than 80 SEK/$\mathrm{kWh_{th}}$, and profitable already today.

The storage sizes highlighted in this thesis, 300 $\mathrm{kWh_{el}}$ and 1 000 $\mathrm{kWh_{el}}$, are fairly extreme, and an unlimited storage capacity would not reduce the cost further. If smaller sizes would have been chosen, the investment calculations might have been more favourable. But since no investment cost were to be considered in this thesis, the close to maximum storage sizes were chosen. If instead calculating for an electrical storage of 150 $\mathrm{kWh_{el}}$ and a thermal storage of 500 $\mathrm{kWh_{th}}$, the investments would be profitable if the cost were lower than 850 SEK/$\mathrm{kWh_{el}}$ for the electrical storage and lower than 150 SEK/$\mathrm{kWh_{th}}$ for the thermal storage. In the future, however, it would be interesting to make more detailed investment calculations to see what storage sizes would be profitable with today's investment costs.

Investigations on how this type of building would affect the surrounding district heating and electricity system would be interesting to do. The district heating network is today already working in a similar way to the building. It has both CHP plants and large heat pumps, and they work in combination depending on the electricity price. Further, installing a larger hot water storage tank in the system would introduce even more flexibility. An electrical storage is, however, most profitable in the building and not in the system (Borg, 2014), and thus, the elelctricity system could not be adapted in the same way.

Another interesting investigation that is not considered in this thesis is what happens within the hour. All optimisations in this model have a time resolution on one hour, and all values are mean values of each hour. The benefits from the energy storage capacities might increase if considering what happens within the hour.

6 Conclusions

A model of heat and electricity supply of multifamily buildings has been developed, including energy storage and solar PV. Investigations on the value of energy storage in combination with solar PV and the possibility to buy both electricity and district heating on spot price were conducted. Of special interest was also the combination of heat pumps and district heating in the building and how that could be utilised together with the energy storage capacities and the solar PV. The optimisation of the energy system in the building was made on the running cost. The goal was to create a model that will optimise the energy supply in the building and to study how the different storage capacities could be used.

The input data for this thesis and the estimations and assumptions made, are based on the planning of Riksbyggen brf Viva. The values for the building were not decided on when this thesis was carried out. The specific building was only used as inspiration and the results should not be directly connected to the future built house.

As expected, the running cost for the building for both electricity and heat decreases with increased storage size, in all the investigated cases. The case with both electricity and heat storage in combination gives the lowest running cost. A cost reduction of 24 % can be achieved with a thermal storage of 1 000 kWh_{th} and an electrical storage of 300 kWh_{el}.

Before this study was made, it was uncertain whether an electrical storage and a thermal storage would be good in combination or if the benefits of one would make the other unnecessary. The conclusion is that the thermal storage is utilised mostly during the winter and the electrical storage is utilised mostly during the summer and that both are contributing to the cost reduction. During the spring and autumn, both storage capacities are utilised and complementing each other. The two different storage capacities are also utilised in different ways. The electrical storage is utilised during the summer to handle the produced PV electricity. This would not be beneficial to do with a thermal storage since the heating demand is too low and the district heating cheap, therefore the electrical storage is useful. The thermal storage is used during the colder months, when the heating demand is larger. A large electrical storage had perhaps been able to lower the running costs during the winter together with the heat pumps, but in that case, the fluctuations in the district heating price could not have been utilised, and the total running cost would have been higher. A thermal storage is furthermore less costly to invest in than an electrical storage.

Both storage capacities reduced the dependencies on electricity and district heating from the grid. An electrical storage of 300 kWh_{el} together with solar PV makes the building self-sufficient on electricity 57 % of the hours of the year, while without any storage only 29 %. The number of hours that the building needs to buy electricity reduces with increased storage capacity, and so does the amount of bought electricity, since less of the produced electricity needs to be sold. With the price model and building considered in this thesis, based on today's Swedish regulations, it is in most cases more favourable to store the electricity and use it later, than to sell it. This is, however, dependent on the surcharge on sold electricity and on the losses in the storage.

Due to the large fluctuations in the marginal production cost of district heating, the share of the heat demand supplied by district heating, compared to what is supplied by the heat pumps, increases with thermal storage size. The periods of low production cost in the district heating network can then be taken advantage of. Remember though that no such marginal pricing exists on district heating today.

Using both district heating and heat pumps in combination in the building when buying both electricity and district heating on spot price, reduces the running cost regardless of thermal storage size. When combining the heat pumps with the produced solar electricity, when optimising the combined heat and electricity system, the advantages with the thermal storage increases, since a larger share of the produced solar electricity can be kept in the building.

The work with this thesis concludes that there are advantages with having both heat and electricity storage in a multifamily building with solar PVs. Deeper investigations of the investments are, however, needed to get to know if the cost reductions are large enough to justify installations of energy storage technologies.

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A

Supplementary material

Supplementary material, both input data and results, are presented in this chapter for the interested reader.

A.1 Input data

The electricity usage per month can be seen in Figure A.1. The entire bar is the total electricity demand of the month. The lowest part of the bar is the building electricity, the middle part is the household electricity and the upper part is charging of EVs. Note that the number of days in each month varies, and therefore for example the bar for February is lower.

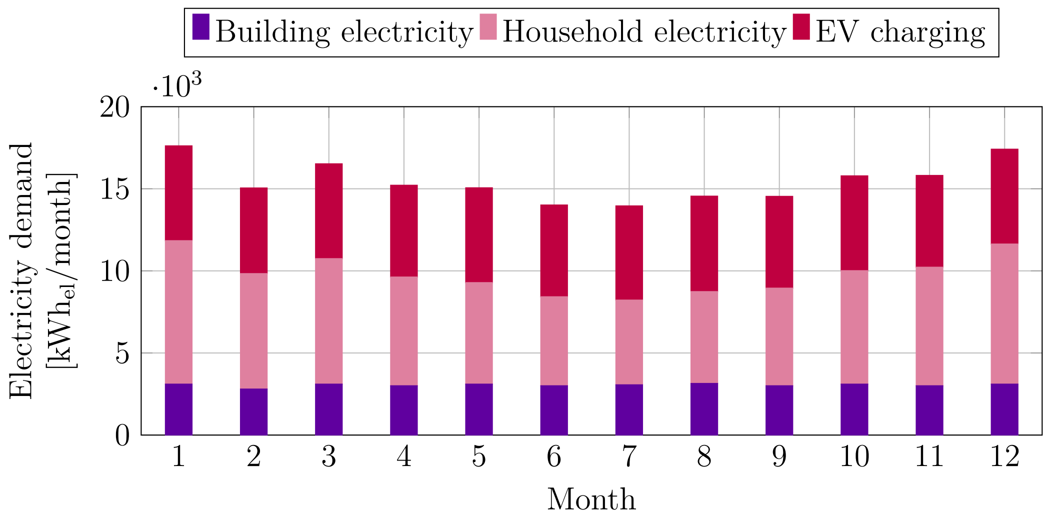


Figure A.1: Share of the electricity demand from the different parts of the electricity demand each month. The entire bar is the total electricity demand (except any electricity to the heat pumps) for each month.

A.2 Result for the combined heat and electricity system

The total running cost per year for the optimisation of the combined heat and electricity system for different combinations of storage sizes can be seen in Table A.1 and A.2, for fixed thermal storage and increasing electrical storage, and vice versa.

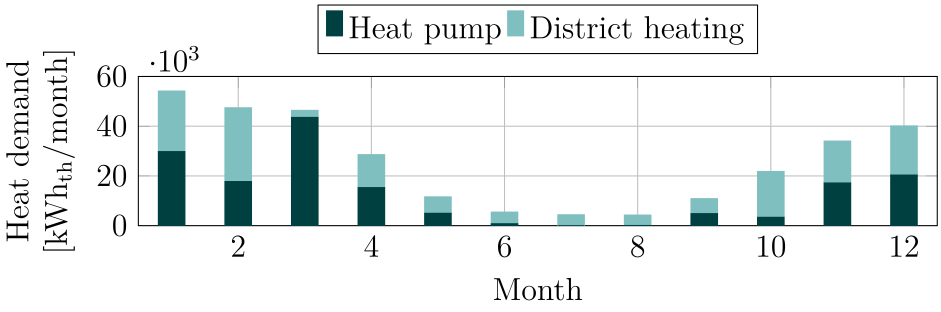
In Figure A.2, the share of district heating compared to the total heat demand for each month, can be seen. Here all four cases are presented: no storage (A.2a), only thermal storage of 1 000 kWh_{th} (A.2b), only an electricity storage of 300 kWh_{el} (A.2c) and both thermal end electrical storage (A.2d).

Table A.1: Reduction on the total running cost when increasing the electrical storage. The thermal storage is in this case 1 000 kWh_{th}.

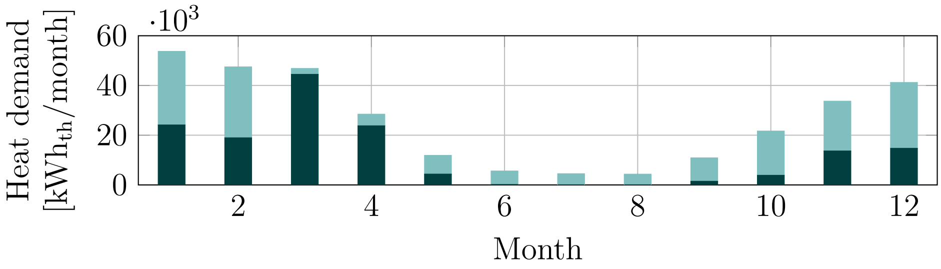
Electrical storage size [kWh_{el}]	Total cost [SEK/yr]	Cost reduction
0	135 180	-
100	124 980	7.5 %
200	117 400	13.2 %
300	113 470	16.1 %
400	112 440	16.8 %
500	111 980	17.2 %
600	111 820	17.3 %

Table A.2: Reduction on the total running cost when increasing the thermal storage. The electrical storage is in this case 300 kWh_{el}.

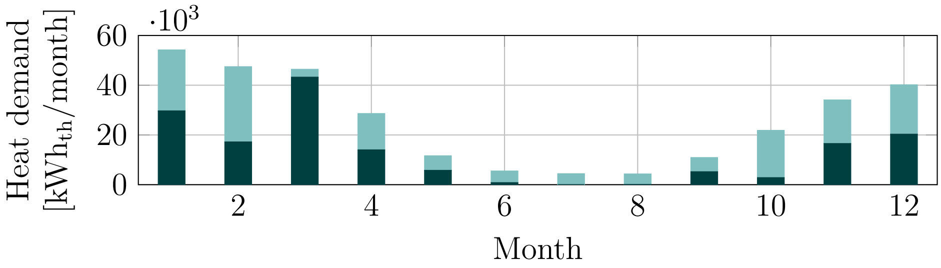
Thermal storage size [kWh_{th}]	Total cost [SEK/yr]	Cost reduction
0	124 320	-
500	115 920	6.8 %
1 000	113 470	8.7 %
1 500	112 690	9.4 %
2 000	112 430	9.6 %



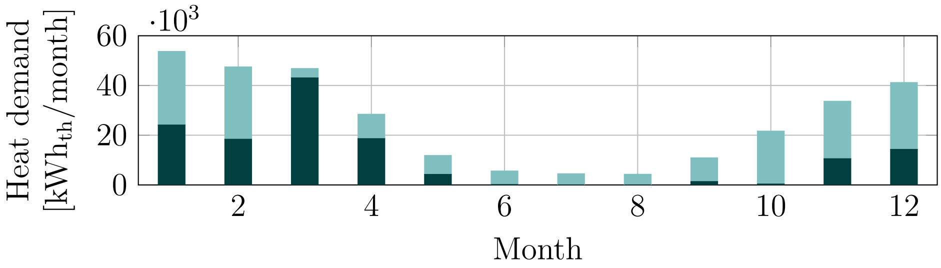
(a) No storage capacities.



(b) A thermal storage of 1 000 kWh_{th}, no electricity storage.



(c) An electrical storage of 300 kWh_{el}, no thermal storage.



(d) A thermal storage of 1 000 kWh_{th} and an electrical storage of 300 kWh_{el}

Figure A.2: Share of the heat demand in the building supplied by district heating, each month, the rest is supplied by heat pumps.

B
Matlab program

The complete Matlab program for the optimisation model can be seen in this chapter. First are the input data and the settings, in the middle the linear programming model defined, and in the end are some output data handling. The linear programming model is solved with Matlab's built in function linprog.

```
%% Input data and settings

load('inputData_1year.mat');

% el data
P_el = max(elUsage) + max(heatUsage.*COP_HP); %kW (max power)
pEl  = pEl_spot;
buy_surcharge  = 0.6075; %kr/kWh
sell_surcharge = 0.0370; %kr/kWh
PV_production  = PV_2013; %change to same year as the price

% DH data
P_DH = max(heatUsage); %kW (max power)
pDH  = pDH_marginal; %choose marginal or mean

% HP data
P_HP = max(heatUsage); %kW (max power)

% el storage
Q_el_cap = 300
q_el_in  = Q_el_cap; %1C ok
q_el_out = -Q_el_cap; %1C ok
startElStorage = Q_el_cap/2; %start with half storage
eta_el_in  = (1-0.07); %charge losses
eta_el_out = (1-0.07); %discharge losses

% thermal storage
Q_th_cap = 1000
q_th_in  = Q_th_cap;
q_th_out = -Q_th_cap;
startThStorage = Q_th_cap/2; %start with half storage
eta_th_in  = 1; %assume no heat losses
eta_th_out = 1;


%% Optimisation

D = length(heatUsage);
M = 72; %looping hours
N = 24; %1 day

ch_elG   = zeros(D,1);
ch_PV    = zeros(D,1);
disch_el = zeros(D,1);
ch_HP    = zeros(D,1);
ch_DH    = zeros(D,1);
disch_th = zeros(D,1);
```

```
use_HP    = zeros(D,1);
use_PV    = zeros(D,1);
curt_PV   = zeros(D,1);
tot_elStorage = zeros(D,1);
tot_thStorage = zeros(D,1);

for i = 1:N:(D-M+1)
    p_el_buy  = pEl(i:i+M-1) + buy_surcharge;
    p_el_sell = pEl(i:i+M-1) + sell_surcharge;
    p_DH_buy  = pDH(i:i+M-1);
    use_el    = elUsage(i:i+M-1);
    PV        = PV_production(i:i+M-1);
    use_heat  = heatUsage(i:i+M-1);
    COP       = COP_HP(i:i+M-1);

    %x = [ch_elG; ch_PV; disch_el; ch_HP; ch_DH;
    %     disch_th; use_HP; use_PV; curt_PV]

    %objective function
    f = [p_el_buy; p_el_sell; p_el_buy; p_el_buy./COP; p_DH_buy; p_DH_buy; ...
        (p_el_buy./COP-p_DH_buy); (-p_el_buy+p_el_sell); p_el_sell];

    %boundaries
    lb = [zeros(M,1);          %ch_elG
          zeros(M,1);          %ch_PV
          ones(M,1)*q_el_out; %disch_el
          zeros(M,1);          %ch_HP
          zeros(M,1);          %ch_DH
          ones(M,1)*q_th_out; %disch_th
          zeros(M,1);          %use_HP
          zeros(M,1);          %use_PV
          zeros(M,1)];         %curt_PV

    ub = [ones(M,1)*q_el_in; %ch_elG
          ones(M,1)*q_el_in; %ch_PV
          zeros(M,1);         %disch_el
          ones(M,1)*q_th_in; %ch_HP
          ones(M,1)*q_th_in; %ch_DH
          zeros(M,1);         %disch_th
          ones(M,1)*P_HP;     %use_HP
          PV;                 %use_PV
          PV];                %curt_PV

    %constraints
    A0  = zeros(M);
    A1  = diag(ones(M,1));
    A1_ = diag(-ones(M,1));
    Ac  = diag(1./COP);
    Ac_ = diag(-1./COP);
    A11 = tril(ones(M)*eta_el_in);
    A12 = tril(ones(M)*eta_el_in);
    A13 = tril(ones(M)/eta_el_out);
    A21 = tril(-ones(M)*eta_el_in);
    A22 = tril(-ones(M)*eta_el_in);
    A23 = tril(-ones(M)/eta_el_out);
    A44 = tril(ones(M)*eta_th_in);
    A45 = tril(ones(M)*eta_th_in);
    A46 = tril(ones(M)/eta_th_out);
    A54 = tril(-ones(M)*eta_th_in);
    A55 = tril(-ones(M)*eta_th_in);
    A56 = tril(-ones(M)/eta_th_out);

    A = [A11 A12 A13 A0  A0  A0  A0  A0  A0;    %UL el storage
         A21 A22 A23 A0  A0  A0  A0  A0  A0;    %LL el storage
         A1  A1  A0  A0  A0  A0  A0  A0  A0;    %charge el storage
         A0  A0  A0  A44 A45 A46 A0  A0  A0;    %UL th storage
         A0  A0  A0  A54 A55 A56 A0  A0  A0;    %LL th storage
         A0  A0  A0  A1  A1  A0  A0  A0  A0;    %charge th storage
         A1_ A0  A1_ Ac_ A0  A0  Ac_ A1  A0;    %LL el buy
         A1  A0  A1  Ac  A0  A0  Ac  A1_ A0;    %UL el buy
```

```
         A0  A1  A0  A0  A0  A0  A0  A1  A1;     %LL el sell
         A0  A1_ A0  A0  A0  A0  A0  A1_ A1_;    %UL el sell
         A0  A0  A0  A0  A1_ A1_ A1  A0  A0;     %LL DH buy
         A0  A0  A0  A0  A1  A1  A1_ A0  A0];    %UL DH buy

    b = [ones(M,1).*(Q_el_cap - startElStorage); %UL el storage
         ones(M,1).*startElStorage;              %LL el storage
         ones(M,1).*q_el_in;                     %charge el storage
         ones(M,1).*(Q_th_cap - startThStorage); %UL th storage
         ones(M,1).*startThStorage;              %LL th storage
         ones(M,1).*q_th_in;                     %charge th storage
         use_el;                                 %LL el buy
         -use_el+P_el;                           %UL el buy
         PV;                                     %LL el sell
         -PV+P_el;                               %UL el sell
         use_heat;                               %LL DH buy
         -use_heat+P_DH];                        %UL DH buy

    %solve
    [x,fval,exitflag,output,lambda] = linprog(f,A,b,[],[],lb,ub);
    if exitflag ~= 1
        i
        output.message
    end

    ch_elG(i:i+N-1)    = x(1:N);
    ch_PV(i:i+N-1)     = x((M+1):(M+N));
    disch_el(i:i+N-1)  = x((2*M+1):(2*M+N));
    ch_HP(i:i+N-1)     = x((3*M+1):(3*M+N));
    ch_DH(i:i+N-1)     = x((4*M+1):(4*M+N));
    disch_th(i:i+N-1)  = x((5*M+1):(5*M+N));
    use_HP(i:i+N-1)    = x((6*M+1):(6*M+N));
    use_PV(i:i+N-1)    = x((7*M+1):(7*M+N));
    curt_PV(i:i+N-1)   = x((8*M+1):(8*M+N));

    tot_elStorage(i) = (ch_elG(i)+ch_PV(i)).*eta_el_in + ...
                       disch_el(i)./eta_el_out + startElStorage;
    tot_thStorage(i) = (ch_HP(i)+ch_DH(i)).*eta_th_in + ...
                       disch_th(i)./eta_th_out + startThStorage;
    for j = i+1:i+N-1
        tot_elStorage(j) = tot_elStorage(j-1) + ...
                           (ch_elG(j)+ch_PV(j)).*eta_el_in + ...
                           disch_el(j)./eta_el_out;
        tot_thStorage(j) = tot_thStorage(j-1) + ...
                           (ch_HP(j)+ch_DH(j)).*eta_th_in + ...
                           disch_th(j)./eta_th_out;
    end
    startElStorage = tot_elStorage(j);
    startThStorage = tot_thStorage(j);
end


%% Handling output data

p_el_buy  = pEl(1:D) + buy_surcharge;
p_el_sell = pEl(1:D) + sell_surcharge;
p_DH_buy  = pDH(1:D);
use_el    = elUsage(1:D);
PV        = PV_production(1:D);
use_heat  = heatUsage(1:D);
COP       = COP_HP(1:D);

buy_el = use_el + ch_elG + disch_el + ch_HP./COP + use_HP./COP - use_PV;
buy_DH = use_heat + ch_DH + disch_th - use_HP;
sell_el = PV - ch_PV - use_PV - curt_PV;

cost_el     = p_el_buy.*buy_el;
revenue_el  = p_el_sell.*sell_el;
cost_DH     = p_DH_buy.*buy_DH;
cost        = cost_el + cost_DH - revenue_el;
```