Solar PV Integrated with Seasonal Thermal Storage and District Heating

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LUND UNIVERSITY

Thesis for the degree of Master of Science
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ISSN: < 0282-1990>
LUTMDN/TMHP-23/5535-SE

Lund 2023

Acknowledgements

This master thesis was commissioned with BayWa r.e. in collaboration with the Faculty of Engineering, Lund university, during the spring period of 2023. It was performed at the department of Energy Sciences.

Firstly, we would like to thank our supervisor Marcus Thern whom we have had good discussions with and who has supported us with advice and guidance throughout the project. Secondly, we would like to thank our examiner Kerstin Sernhed for her advice and guidance. We would also like to thank our contact and supervisor at BayWa r.e., Benjamin Berg for his support with his expertise within the area during the whole process of the project and for all the productive discussions.

25 May 2023

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Abstract

In order to contribute to reaching the climate goals of the future, power-to-heat (P2H) technologies are a possible solution. A heat pump (HP) or an electric boiler (EB) can be used to produce warm water by utilising cheap electricity from photovoltaic (PV) parks in the summer when there are many hours of sunlight. The warm water can then be stored until winter for use in district heating (DH) when the heat demand is big. This thesis investigates whether this is economically viable and what the most impactful factors are on the business case, as well as which P2H technology and which type of storage is most promising. This is done by designing a model in Microsoft Excel which allows different system configurations to be tested. The investigations show that the pit heat storage seems most suitable for this type of system, and that whether the HP or EB is the best choice depends on the local conditions. It seems like the EB is most suitable for situations where a low number of operating hours are desired, while the HP is better suited for a high number of operating hours. The most sensitive parameters appear to be the heat sales price and storage capital expenditures. The spot price distribution also affects the results a lot, and so the results depend on how much the spot prices will vary in the future and how high they will be. The DH fuel costs are also an important factor, as they determine which heat sales price is acceptable on the market.

Sammanfattning

För att bidra till att vi ska nå framtidens klimatmål så är power-to-heat-teknologier en möjlig lösning. Man kan använda en värmepump eller elpanna för att producera varmvatten genom att utnyttja billig el från solcellsparker under sommaren när det finns många soltimmar. Det kan sedan lagras till vintern för att användas i fjärrvärmenät när värmebehovet är stort. Det här examensarbetet undersöker om det här är ekonomiskt lönsamt och vilka faktorer som påverkar affärsfallet mest, samt vilken power-to-heat-teknologi och vilken sorts lagerteknik som är mest lovande. Detta görs genom att designa en modell i Microsoft Excel som gör att olika systemkonfigurationer kan testas. Undersökningarna visar att gropḣålslager verkar passa den här sortens system bäst, och att lokala förutsättningar avgör om en värmepump eller elpanna är det bästa valet. Elpannan verkar vara mest lämplig när ett lågt antal drifttimmar önskas, medan värmepumpen är bättre lämpad för ett högt antal drifttimmar. De mest känsliga parametrarna verkar vara säljpriset för värmen och investeringskostnaden för lagret. Spotprisfördelningen påverkar också resultaten mycket, så resultaten beror på hur mycket spotpriserna kommer variera i framtiden och hur höga de kommer vara. Kostnaderna för fjärrvärmebränsle är också en viktig faktor, eftersom de avgör vilket säljpris för värme som är acceptabelt på marknaden.

Nomenclature

CAPEX = Capital expenditures

CHP = Combined heat-and-power

COP = Coefficient of performance

DH = District heating

EB = Electric boiler

GWh = Gigawatt hour

HP = Heat pump

IRR = Internal rate of return

LCOH = Lifecycle cost of heat

MW_e = Megawatt electric

MW_{th} = Megawatt thermal

MWh_e = Megawatt hour electric

MWh_{th} = Megawatt hour thermal

NPV = Net present value

O&M = Operation and maintenance

P&L = Profit and loss

PV = Photovoltaic

P2H = Power-to-heat

STE = Solar thermal energy

TSO = Transmission system operator

TWh = Terawatt hour

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1 Introduction

The world is well on its way to a more sustainable future with a large share of renewable energy, but more needs to be done. In order to ensure that we reach the climate goals of the future, we need even more renewable energy sources. A growing renewable technology is solar photovoltaic (PV) power, which had the second largest growth in the world 2021 out of renewable technologies, exceeding a production of 1 000 TWh. It is also on its way of becoming the cheapest option for new electricity generation plants in the world [1], making it a very promising technology.

PVs account for less than 1 % of the total electricity production in Sweden today. However, in 2016 the Swedish government established a goal that the country should have 100 % renewable electricity production by 2040. On behalf of the government, the Swedish Energy Agency has developed a strategy proposal for how to increase the usage of solar energy for electricity production. The proposal suggests that, given that some promotional measures are implemented, (5-10) % of the total electricity usage in Sweden could be produced by PVs [2]. However, all PV parks in Sweden may not be profitable [3], and so it may be necessary to find solutions for that.

Another current problem in PV production in Sweden is that there are a lot of available sunlight hours during summer, when the sales price for electricity is generally low, but almost none in winter when sales prices tend to be higher. Meanwhile, there is a big demand for heat in winter. A coupling of the heating and power sectors appears to be a possible solution to contribute to the decarbonisation of both sectors, as well as handling the flexibility required by PV electricity production. Moreover, power-to-heat (P2H) appears to be a cost-effective way to help integration of renewable energy [4]. By using a P2H technology such as an electric boiler (EB) or a heat pump (HP) and utilising the cheap electricity from the PVs during summer, warm water could be stored until winter and be used in district heating (DH). This way, energy could be saved and the business case for the solar park could be better. This will be investigated in collaboration with the company BayWa r.e.

1.1 Objectives

The main objective of this thesis is to answer the question of how an integration of solar PV with seasonal storage and DH could work, as well as what factors affect this kind of system and its profitability the most. We also want to investigate whether the HP or EB is most suitable for this kind of system, and to understand the cost picture and limitations of the system. In order to investigate this, we first need to decide which kind of seasonal storage technique is suitable for the system, which will be done before any cases are examined. This results in two systems, one with a HP and one with an EB, and we will compare these systems in order to further deepen our understanding of which factors affect the systems the most. Firstly, we can try to identify which sources of electricity are the best choice for the system from parameters we identify as important. Thereafter, we can apply these systems on a medium size Swedish city with a DH system and a certain yearly DH heat demand, and in this case, we chose Filipstad as an example. This way we can examine whether the HP or EB is most suitable for the chosen city’s conditions. Which technology is the most suitable option depends on the profitability of the system and the most important factors affecting the system. The profitability will be investigated by computing the heat production costs for each system and will also be analysed in a simplified profit and loss (P&L) statement for one of the P2H technologies. Thanks to the

P&L statement we can also investigate at what heat sales price the business model could be profitable for the investigated system. A reasonable sales price is determined by looking at DH fuel costs and also by comparing to another alternative heat source, namely solar thermal energy (STE). A discussion will then follow to sort out the most important results in order to draw conclusions and answer our questions.

1.2 Delimitations

In this report, we only focus on the Swedish market and conditions, and primarily the southern parts of the country. We do not consider the profitability from the PV park's point of view, but instead focus on building a model which can give us an idea of what heat production price can be expected. We do not take into account regulatory frameworks and only focus on the boundary conditions of DH. In some parts of the report a conversion from SEK to € has been made and the exchange rate has been taken from Xe currency converter the 11th of May 2023 [5].

1.3 Problem Statement

In order to meet the objective of this master thesis, some questions need to be answered. We wish to investigate how a solution could look when integrating solar PV with seasonal storage and DH and what factors affect this kind of system and its profitability the most. To be able to answer that, we need to find out what the limitations are for the system. Furthermore, we wish to investigate what the production cost for the produced heat is in a specific case.

1.4 Division of Work

This master thesis has been a collaboration between Hannah Ekström and Lovisa Thalén. The work has been evenly distributed and both have been involved in all parts, but for some sections the main responsibility has been divided. Hannah has mainly been responsible for the following parts:

- Chapter 2: Principal Sketch over the System Configuration
- Chapter 6: Thermal Storage
- Chapter 7: District Heating
- Chapter 10: The Operating Strategy
- The figures

Lovisa has been mainly responsible for the following parts:

- Chapter 1: Introduction
- Chapter 3: Solar PV
- Chapter 4: The Electrical Grid and Electricity Prices
- Chapter 5: Power-to-Heat Technologies
- Chapter 8: Competitors

The remaining parts have been performed in complete collaboration.

1.5 Outline of the Thesis

Here the outline of the thesis is presented and what is included in each chapter.

- Chapter 2: Principal Sketch over the System Configuration. In this chapter there is a brief description of how the system works and what different parts it consists of.

Relevant theory regarding the subjects of this report, from the literature review, is presented in chapters 3-9:

- Chapter 3-7: Solar PV, The Electrical Grid and Electricity Prices, Power-to-heat technologies, Thermal Storage and District Heating. These chapters describe the different parts of the system, how they work and what circumstances apply for the system and the project.
- Chapter 8: Competitors. This chapter describes some competitors that exist for the system.
- Chapter 9: Economics. In this chapter, the different methods for analysing the economics of the system are presented.

The method of this project and how our model of the system is built is presented in chapters 10 and 11:

- Chapter 10: The Operating Strategy. This chapter presents flow charts of how decisions are made in the system. The choice of storage technology is also presented in this chapter in order to be able to build the model.
- Chapter 11: The Model. This chapter presents how the model is structured, what parameters are included and what different cases are looked at and calculated.

The results of the project are presented in chapter 12:

- Chapter 12: Results. In this chapter the results of the different cases, sensitivity analysis and P&L are presented.

A discussion of the system and the results are presented in chapter 13:

- Chapter 13: Discussion. This chapter presents a discussion of what factors affect the system and its profitability, based on the information from the results.

The thesis ends with conclusions and ideas for future work in chapters 14 and 15:

- Chapter 14-15: Conclusions and Future Work. In these chapters, the main conclusions and recommendations for future work of the project are presented.

2 Principal Sketch over the System Configuration

The system consists of several different parts, and these are illustrated in Figure 1 below. The first part of the system is a solar PV park, which is either connected directly to the power grid or to a P2H unit. In our case, the P2H unit is either a HP or an EB. The P2H unit is in turn connected to a thermal seasonal storage as well as directly to the DH network.

The PV park produces electricity by utilising the sunlight and can then either sell it to the power grid or the P2H unit (HP/EB). The agent for the P2H unit can also buy electricity directly from the grid. When the P2H unit is running, it utilises the electricity to produce heat, which is then either sent to the storage or directly to the DH network. The heat is only sent to the storage if there is no current addressable heat demand in the DH network, which is decided based on how much of the total heat demand we wish to satisfy, and it is stored until there is a demand.

All these different parts of the system are described in the following sections of the report to provide a solid background of the different technologies and the circumstances that apply for the system.

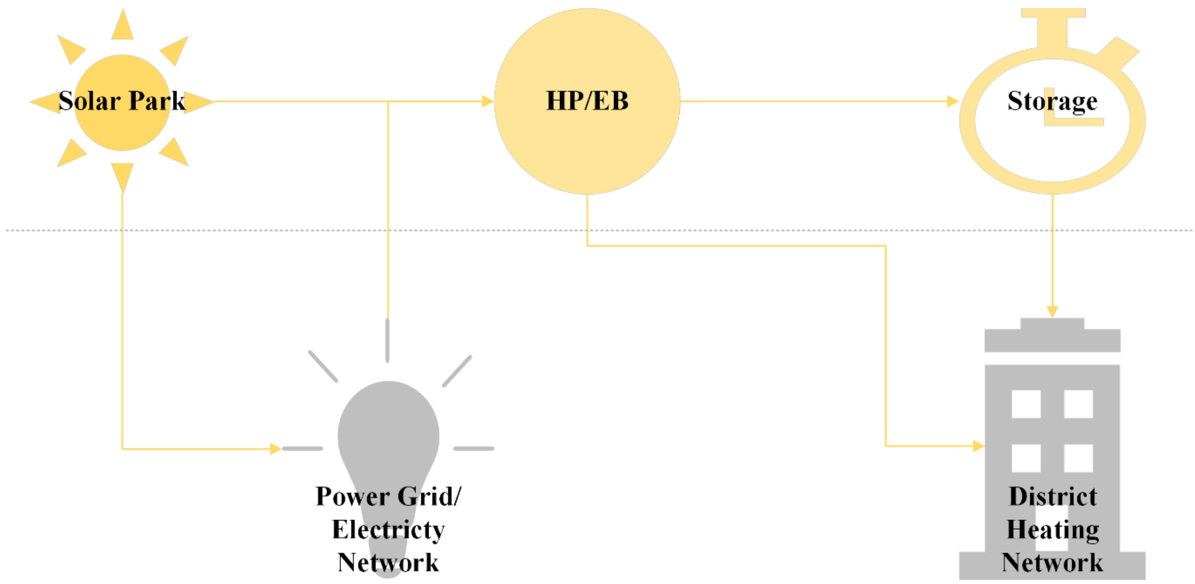

Figure 1. Our system and its different parts.

3 Solar PV

A PV system is made up of PV panels, or modules, which in turn are made up of PV cells. PV cells convert sunlight into electricity by utilising a semiconductor material. When the sunlight hits the semiconductor, the light is absorbed. The energy from the light is then transferred to electrons within the semiconductor, which creates an electrical current. The current flows through metal contacts before it reaches an inverter, which converts the current from direct to alternating current, so it can finally be delivered to the electrical grid [6].

3.1 PV in Sweden

As of 2022, there were 42 PV parks with an installed capacity of more than 1 MW_e in Sweden. Out of these, only five have a capacity of more than 6 MW_e, as seen in Table 1. The five biggest installed PV parks in Sweden as of 2022Table 1. The two biggest installations are found in Sjöbo (commissioned in 2019, expanded in 2021) and Skurup (commissioned in 2022), each with a capacity of 18 MW_e [7].

Table 1. The five biggest installed PV parks in Sweden as of 2022 [7].

Placement	Installed capacity [MW_e]
Sjöbo	18
Skurup	18
Strängnäs	14
Linköping	12
Åhus	7.2

3.2 Solar Irradiation

Solar irradiation varies and depends on time of day, season, location, local landscape and weather [8]. A map over the annual solar irradiation in Sweden can be found in Figure 2 below. It can be seen that the irradiation in southern parts of Sweden is generally at about the same levels and higher than in the north.

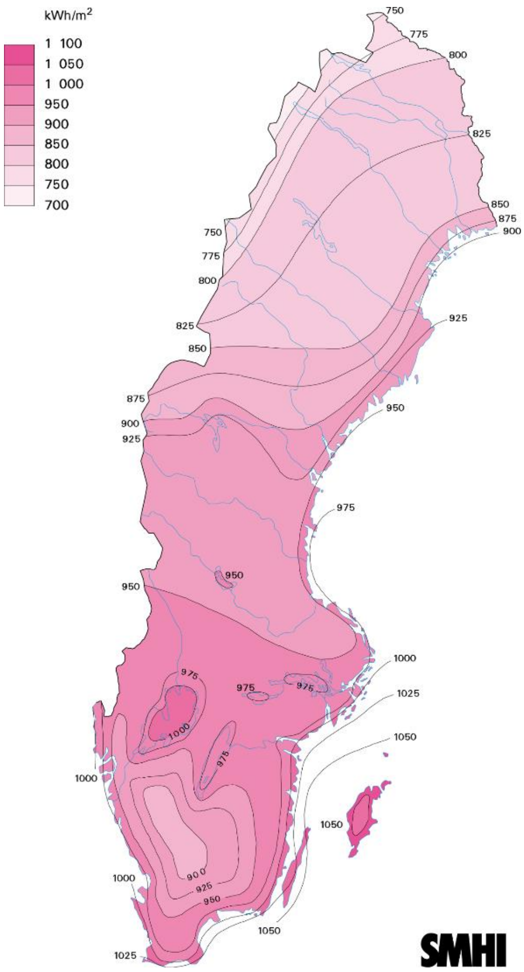

Figure 2. A map displaying the annual solar irradiation in Sweden [9].

4 The Electrical Grid and Electricity Prices

Sweden is divided into four bidding zones: SE1, SE2, SE3 and SE4, as can be seen in Figure 3. The zones are used to handle bottlenecks in the transmission system, which are present between the northern and southern parts of Sweden. Due to the lack of electricity production in SE3 and SE4, the prices tend to be higher there [10].

Figure 3. Map displaying the four bidding zones in Sweden [11].

4.1 Electricity Prices in Sweden

The past few years, since 2020, the prices have been more volatile than before. The differences between SE1 and SE2 compared to SE3 and in particular SE4 are greater than historically. The prices in SE1 and SE2 tend to be at about the same level, while SE3 and SE4 are usually at the same level [12], [13]. The spot prices can vary a lot due to different reasons. For instance, during late fall and winter 2021/2022, the prices gradually increased following unusual weather conditions, high prices on fossil fuels and a free European electricity market. The Covid-19 pandemic also had a role in the change in spot prices [14].

As can be seen in Figure 4, the average spot prices are expected to decrease gradually. If the predictions are correct, the average spot prices in 2026 and 2027 will reach approximately the same levels as 2019. The spot prices for SE3 in 2019, provided by BayWa r.e., can be seen in Figure 5 below, and they appear to be quite steady over the year. The spot prices are expected to become more volatile in the future, in part because of a larger share of renewable electricity production [15].

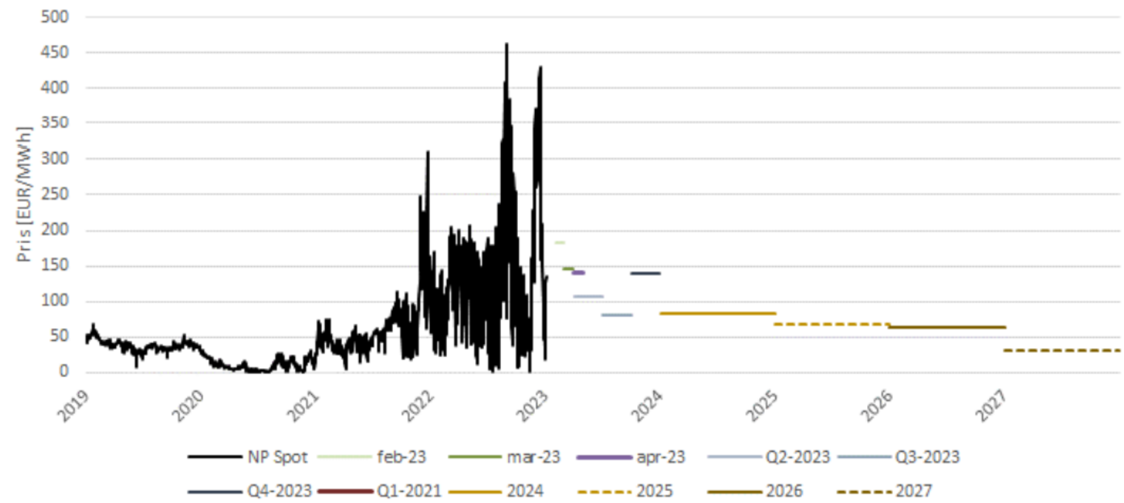

Figure 4. Historical and expected future average spot prices in Sweden [15].

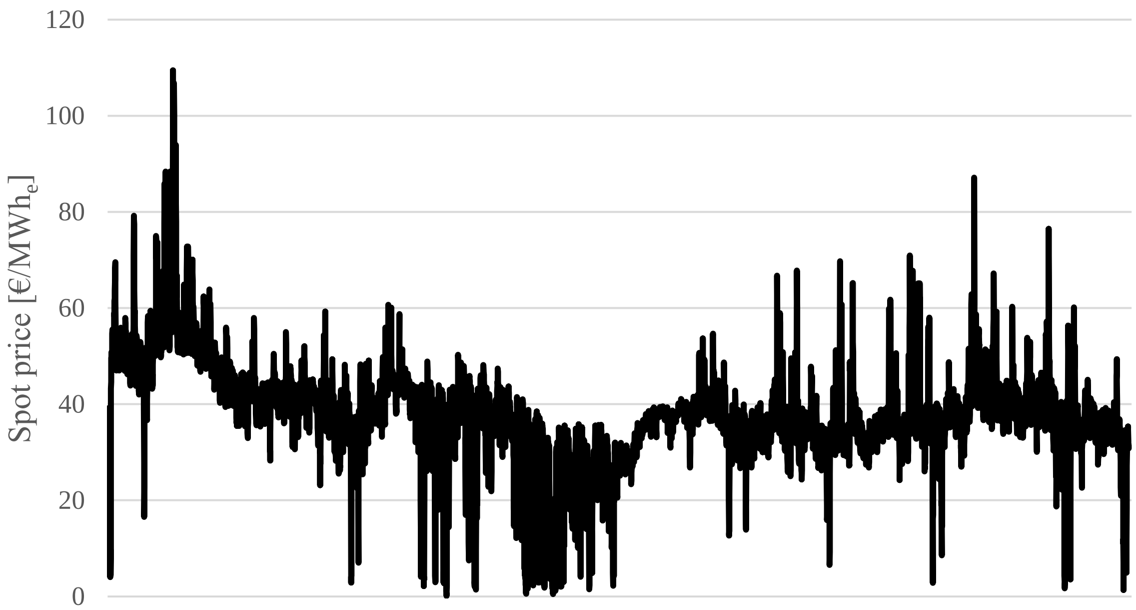

Figure 5. Spot prices for SE3 in 2019.

4.2 The Swedish Electrical Grid and Grid Capacity

The Swedish electrical grid consists of the transmission and distribution grid, as well as connections to other countries' grids. The transmission grid is owned and managed by Svenska kraftnät and runs through the entire country. It transports large amounts of electricity from the biggest producers to the distribution grids and other countries. The distribution grid transports the electricity from the transmission grid to the regional and finally the local grids. The local grids are the connection point for most consumers, such as households and companies, and are owned by many different grid companies. The regional grids are owned by larger grid companies and large consumers and some medium-sized producers are usually connected directly to this grid. Small producers can be connected to the local grids, for instance consumers who sell their excess produced electricity [16].

There are constraints in all of these grids in terms of how much electricity can be transported. When there is sufficient power available in the entire system, but it is still not possible to transport enough of it to satisfy the demand in a specific geographical zone, there is a capacity shortage in the grid [17]. The grid capacity varies depending on location: for a city the size of Filipstad the capacity is approximately 15 MW_e and for Stockholm approximately 1500 MW_e [18].

5 Power-to-Heat Technologies

P2H describes a process where electricity is used to generate heat and is considered a good way to produce environmentally friendly heat [19]. Two kinds of P2H technologies, HPs and EBs, are described below.

5.1 Heat Pumps

A HP is a technical device which transfers heat from a colder place to a warmer place, although it is also possible to use for cooling. The lower temperature place is referred to as the source, while the higher temperature place is called the sink. The heat transfer is accomplished by providing the HP with additional electrical energy, enabling it to pump the heat from the source to the sink, ultimately resulting in an even colder source and a warmer sink [20]. This type of HP is called a compression HP [21]. Some common sources for residential heat pumps include the outside air and ground heat or ground water. Common sinks include the inside air and domestic hot water. The efficiency of a heat pump is often measured by the coefficient of performance (COP), which is a ratio between the amount of heat delivered and the amount of electric power provided [20]. The COP for a compression HP is usually between 3 to 5. To reach high values, it is optimal to have a low temperature difference between the source and sink [21].

HPs are also suitable for energy systems where electricity plays a key role, since they can efficiently integrate electricity in those systems. They can reduce the load on the electrical grid and reduce power consumption, particularly when energy storage is also utilised. Furthermore, if the HP is driven by electricity, there are no direct emissions from burnt fuel. Another advantage is the fact that the technology can use energy from different sources which would otherwise not have been utilised by other technologies in heat production. When used for DH, the HPs usually have an output temperature of around 72 °C, but more expensive high-pressure HPs are also available when (80-90) °C is needed [21].

Different types of sources include ground, air, water or liquid [22] and excess heat [21]. The two primary types of ground-source installations are vertical boreholes and horizontal shallow-grids. STE is utilised by both systems, but more so by the horizontal grid, while the borehole system also partly uses geothermal heat. The borehole system is somewhat more expensive but requires less surface area than the horizontal grid, which uses the surface level of soil. The boreholes can be drilled in nearly any type of ground, but ideally in bed rock. They also provide more favourable temperature conditions, making them more efficient, as the surrounding temperature in the ground is warm and more stable than above ground [22].

Air-source HPs are especially cost effective if used for both heating and cooling. Outdoor air is abundant and can be used as a heat source at temperatures as low as -20 °C. Water-source HPs on the other hand can utilise either sea, surface, ground, sewage or industrial wastewater as a heat source. Wastewater has a higher temperature than the natural sources of water and is a good source for use in DH [22]. Excess-heat-source HPs are also a good fit for DH, as they can utilise the left-over heat from industries to heat water. The technology can also reduce the energy consumption in industries and therefore be advantageous for the whole sector [21].

Table 2 shows data for two different HP technologies. It is evident that the excess-heat-source HP is cheaper than the air-source one, but both technologies are expected to become more affordable in the future, especially the air-source HP. However, that is uncertain as it depends on future fuel and electricity costs [21].

Table 2. Parameters for a compression HP with a capacity of 10 MW_{th} using excess heat or air as source in the year 2030 [23].

	Excess heat-source	Air-source
Technical lifetime [years]	25	25
CAPEX [M€/MW_{th}]	0.57	0.76
- Of which equipment [M€/MW_{th}]	0.46	0.61
- Of which installation [M€/MW_{th}]	0.1	0.14
- Of which grid connection [M€/MW_e]	0.01	0.02
Startup cost [€/MW_{th}/startup]	10	10
Warm startup time [hours]	0.1	0.1
Cold startup time [hours]	1	1

5.2 Electric Boilers

EBs generally consist of two different heating element types: electrode boilers and electrical resistance units. Typical electrode boiler units span between (5-50) MW_{th}/unit, while electrical resistance units have capacities up to 5 MW_{th}/unit. Larger installations are also possible but usually consist of a combination of several units. EBs with a larger capacity of at least a few MW generally utilise electrode boilers to heat the water. By feeding power to the electrodes, which causes an electric current to flow in the water between the electrodes, the water is heated [21]. The electrical resistance technology functions like a regular household hot water heater. The electric current causes particles to collide with each other which causes friction, and in turn, heat [24].

EBs operate at nearly 100 % efficiency and require (20-40) m^2/unit as well as (5-6.5) m of height. EBs used for DH purposes are typically installed as peak load production units and the technology is very flexible since it can start up in only a few seconds and regulate the production without a major loss in efficiency. Figure 6 illustrates this and shows that the EB clearly ramps up and down faster than the combined-heat-and-power (CHP) technology as well as a HP. The use of EBs in DH systems mainly comes down to a demand for ancillary services, for instance by utilising wind energy. Since it is a mature technology, it is not expected to become much more affordable in the future [21]. Table 3 shows some different parameters for an EB.

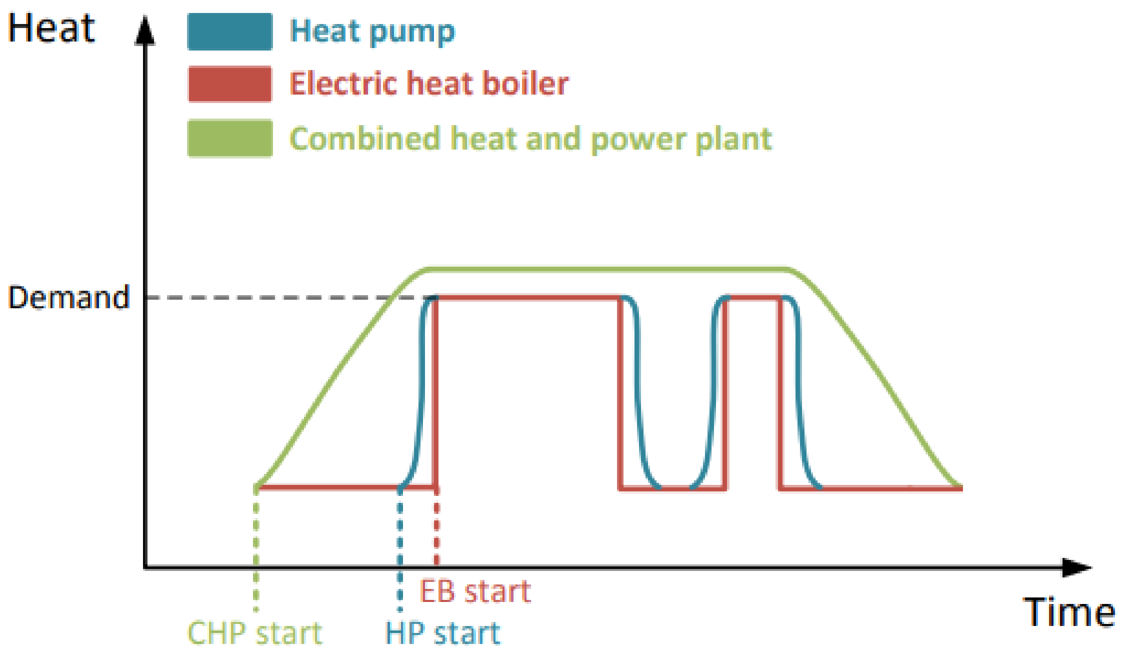

Figure 6. Ramp-up-and-down time for HP, EB and CHP technologies [25].

Table 3. Parameters for an electric boiler in the year 2030. Investment and operation and management (O&M) costs are in relation to an operation time of approximately 500 h/year [21].

	0.06-5 MW_{th}
Technical lifetime [years]	20
CAPEX [M€/MW_{th}]	0.14
- Of which equipment [M€/MW_{th}]	0.11
- Of which installation [M€/MW_{th}]	0.3
Startup cost [€/MW_{th}/startup]	0
Warm startup time [hours]	0.01
Cold startup time [hours]	0.08

6 Thermal Storage

Thermal energy is in great demand, but on the other hand there is also plenty of thermal energy available. The problem is that there is a time difference between the generation and consumption of thermal energy, as well as a cost difference between peak and off-peak hours of the day. If the thermal energy would not be utilised, it would simply disappear into the environment. To prevent this, a thermal energy storage can be used by storing excess heat until it is consumed.

6.1 Sensible Storage

The sensible heat storage method collects thermal energy from the sun and converts it into sensible heat in a selected material, which can then be retrieved when heat is required. The amount of heat that can be stored is determined by the specific heat of the material and its temperature increase. Water is often used as a material in heat storage due to its high specific heat and high-capacity rate while being charged and discharged. Compared to other alternatives, sensible heat storage is considered to be a relatively mature technology for seasonal energy storage [26]. Sensible heat storage is the most common and developed method for thermal energy storage. Compared to latent and thermochemical heat storage, it is both a cheaper and simpler method [27].

Many of the sensible storage techniques are based on the principle of thermal stratification, which means that hot liquid floats on top of cold liquid because of the density differences within the material. From an exergy perspective, a layer where stratification occurs is more valuable than a layer with homogenous temperature [28].

The energy balance of the land volume, surrounding the storage, changes when using geoenergy and over time a new energy balance occurs. Depending on the original ground temperature and the equilibrium temperature, a new equilibrium state can be reached slowly and over a few years [29].

Different materials are used for different temperatures. Water is often used as the storage material for temperatures below 100 °C, and for higher temperatures ceramics and liquids in the form of molten salt can be used [30]. There are different types of sensible heat storage techniques, for example accumulator tanks (also called water tank systems), aquifer systems, rock beds, borehole storage and pit heat storage [26]. The different techniques are described below.

6.1.1 Accumulator Tanks

An accumulator tank is the same as a water tank system and can be described in a similar way as a thermos. The concept of an accumulator tank is that water is stored in a well-insulated container [27]. The tank is charged when there is a surplus of heat and discharged when the load is higher than the network can handle [28]. Accumulator tanks are most often used for managing daily load variations in DH, and not seasonal storage [31]. Accumulator tanks and seasonal storage are built for different purposes and the differences between them are the cost of the storage volume and the relation between power and energy. Accumulator tanks are built to work on short time scales and that is why they normally have a greater charge and discharge power compared to storage energy [32].

6.1.2 Aquifer Systems

An aquifer is a naturally existing room that is located beneath the ground and filled with water [27]. The groundwater is used to carry the thermal energy in and out of the aquifer. To connect to the aquifer two thermal wells are drilled, one for hot water and one for cold water. The energy is stored in the groundwater, as well as in the grains that form the aquifer. A thermal front with different temperatures develops when the groundwater passes the grains [33].

Aquifer storage is used both for daily and seasonal load variations in district cooling. It is less suitable for storage of heat at temperatures higher than (20-25) °C, since otherwise the energy losses are high. In Sweden the aquifers are mainly located above rock foundations in shallow gravel pits, which causes the heat to leak out to the air. That is the reason why aquifers are more suitable for district cooling in Sweden. In other countries the rock foundation is layered and water bearing rock layers can exist further down below denser rock layers, which makes it possible to store heat with a higher temperature. The discharge temperature among the aquifer storages in Sweden varies between (8-28) °C, which is lower than the temperature levels in the DH networks. Aquifer systems have a relatively low investment cost and an Energiforsk study, where different storages in Sweden were identified, showed that the investment cost for aquifer systems was between (1-25) kSEK/MWh_{th}. This is roughly between (0.09-2.2) k€/MWh_{th}, but most of them were lower than 0.9 k€/MWh_{th} [34].

6.1.3 Rock Beds

The surrounding rock acts like a warehouse for storage of hot water in a rock bed. Normally the temperature of the stored water is between (60-90) °C, but rock beds can also be used for seasonal storage of cold in the form of snow. Unfortunately, rock beds are associated with large investments and have had difficulty competing against borehole storage, which has proven to be more cost-efficient [29]. The investment cost for rock beds can be between (20-25) kSEK/MWh_{th}, which roughly is between (1.8-2.2) k€/MWh_{th} [34].

6.1.4 Borehole Storage

A borehole storage exchanges heat and cold with the rock foundation through many vertical boreholes. A fluid circulates through these boreholes and heats and cools the nearby rocks. With a large number of closely spaced boreholes, a large volume of rock can be heated and cooled. This makes borehole storage a good method for seasonal storage, since heat is taken from the rocks during the winter and reintroduced in the summer [35].

The boreholes are normally around (100-300) m deep, and the temperature is even during the year in the ground at these depths. A borehole storage has a long lifetime with little maintenance. It is a technology that is effective and adaptable and that can be applied almost everywhere in Sweden [29]. The discharge temperature varies between (20-55) °C and the efficiency can be between (45-63) %. Borehole storages also have a relatively low investment cost and from the study that Energiforsk performed, the investment cost was between (1-25) kSEK/MWh_{th}, which roughly is between (0.09-2.2) k€/MWh_{th}, but most of them were lower than 0.9 k€/MWh_{th} [34].

6.1.5 Pit Heat Storage

Pit heat storage is an excavated shaft in the ground, where warm water is stored and the surrounding soil isolates and stabilizes. The storage can also be filled with gravel, but then it has slightly poorer thermal properties [34]. This type of storage is often used as seasonal storage and has both high efficiency (between (64-86) %) and energy density [34], [36]. It is also easy to build and operate. Temperature losses are expected from this type of storage method, but with a good cover that insulates properly, the temperature losses can be reduced [34].

This type of storage has a high operating temperature, that can be between (10-90) °C. The investment cost can vary a lot, between (2-66) kSEK/MWh_{th}, which roughly corresponds to (0.18-5.9) k€/MWh_{th}. However, most of them are in the range of (2-15) kSEK/MWh_{th} (0.18-1.3 k€/MWh_{th}) [34]. The investment cost, from a pit heat storage located in Denmark with a heat storage capacity of 6 000 MWh_{th}, was 0.455 k€/MWh_{th}, which is in the lower range of the investment cost for pit heat storages [37]. A schematic figure of the storage can be seen in Figure 7 below.

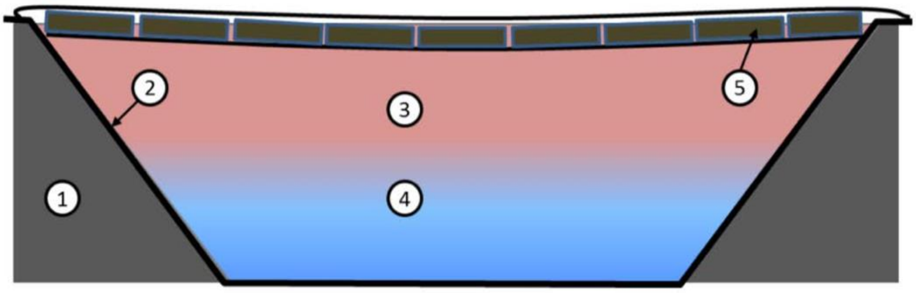

Figure 7. A schematic figure of pit heat storage, where 1) surrounding soil, 2) water diffusion sealed rubber mat, 3) warm water in the upper layer, 4) cold water in the bottom layer, 5) floating insulated cover [34].

6.2 Latent Heat Storage

With latent heat storage the storage medium changes phase during charging and discharging. The energy is used to change phases and not to change the temperature in the medium. Examples of storage medium are paraffins, molten salt and metals. Latent storage can be used where ice is produced or stored seasonally to provide cooling during thawing. To provide heat, latent storage is more suitable when there is high energy density, low storage or constant temperature is a requirement [28].

The difference between latent storage and warm water storage is that the former has a transition temperature and no energy losses to the environment. The supply temperature to the storage must be higher than the transition temperature and the return temperature will never be lower than the transition temperature, when charging the storage, because of the phase changes. This method is under development and more research in this area is needed. Compared to the sensible storage methods, the investment cost for latent storage is much higher as the lowest one is around 400 kSEK/MWh_{th}, which roughly is 35.6 k€/MWh_{th}. The operating temperature for a latent heat storage is up to 90 °C [34].

6.3 Thermochemical Heat Storage

During the charging stage, thermal energy is used to separate one substance into two products through an endothermic reaction. The two products are kept separate as long as energy is stored. An exothermic reaction takes place when the storage is discharged, and the two products are combined again into the original substance [28].

The thermochemical heat storage method is under development and in an even earlier stage than the latent storage method. The chemical reaction is locked against a temperature, but this can be influenced since it depends on pressure. One problem with the technique today is that clumping can arise, which can lead to that the amount of energy available in the storage is reduced, the power is limited, and the system can come to a stop. This can then lead to additional costs. The investment cost for thermochemical heat storage is already much higher than for the sensible storage methods, with the lowest one around 200 kSEK/MWh_{th}, which roughly is 17.8 k€/MWh_{th}. The operating temperature for a thermochemical heat storage is between (30-120) °C [34].

7 District Heating

DH is based on heating water and provides one or more buildings with heated water. The customers utilise the heated water for heating, through heating loops in the floor or in radiators. With DH, the customers can also use the heat to provide domestic hot water. Different energy sources can be used to produce it, for instance household waste, bioenergy and heating oil. There are different kind of heat loads in DH, namely base load and peak load. Base load fuel often consists of waste or bioenergy and is the cheapest energy source. Peak load fuel often consists of oil or gas and is needed because of the variations in heat power demand [38].

There are some requirements regarding the temperatures in DH. The networks today are mainly built for high supply temperatures, around 86 °C, while the future low-temperature networks have a span of (10-70) °C. This new generation of DH shows a higher efficiency and introduces new sources of energy with a lower temperature, such as STE, geothermal energy and waste heat [39]. There are however examples of lower acceptable temperatures for the old DH networks as well, as can be seen in Figure 8 below. It also shows that the required temperature can vary with the outdoor temperature.

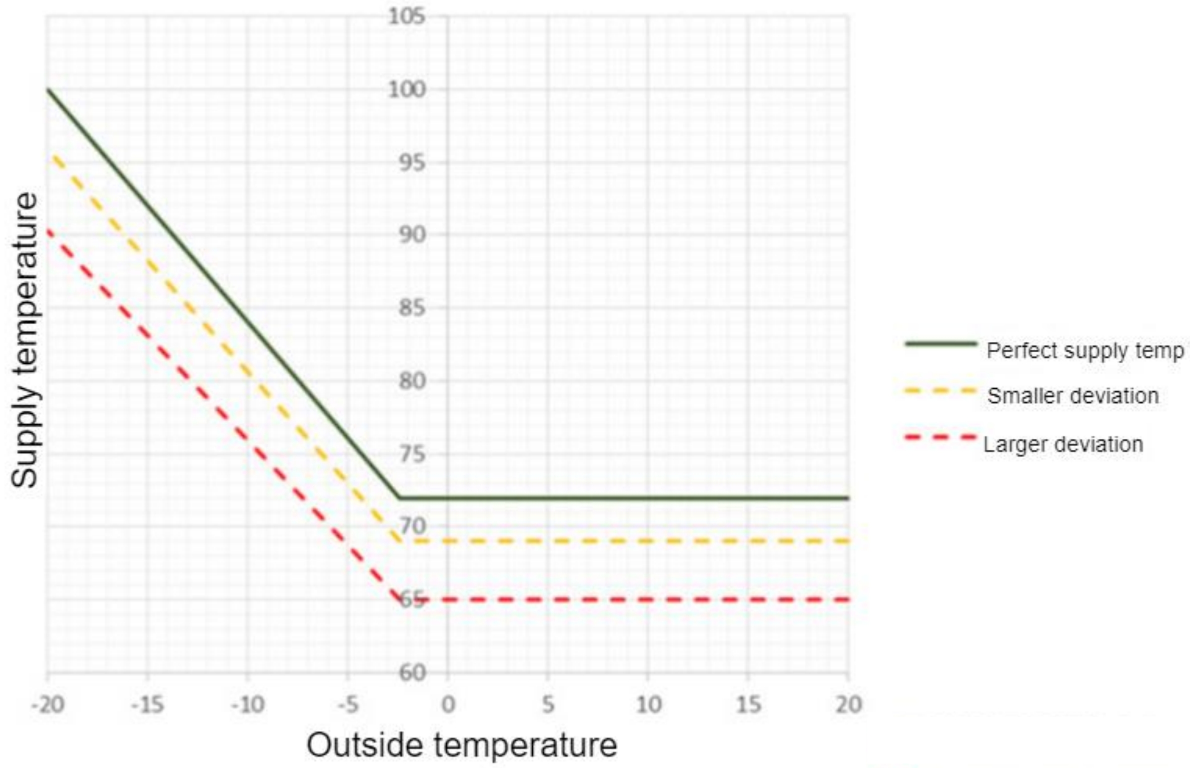

Figure 8.Temperature requirements (°C) in supply temperature for DH networks [40]. The text in the figure has been translated from Swedish.

7.1 Fuel Mix

As seen in Table 4, the fuel mix for DH companies in Sweden mainly consists of biofuels, followed by waste. Both of these fuels utilise energy which would otherwise have gone to waste – in the case of biofuels, this includes wood waste and waste from the wood industry or the felling of forest. A majority of the energy which is supplied to the heat production is either renewable or recovered, and fossil fuels make up less than 1 % of the fuel in the DH systems [41].

Table 4. An overview of the most used fuels for DH in Sweden 2021 [41].

Fuel	Share of energy consumption [%]
Biofuels	45.7
Waste	21.0
Flue gas condensation	10.7
Industrial excess heat	8.2

The price levels for wood fuels used in heating plants can be seen in Figure 9 below. Refined wood fuels are the most expensive and accounts for the highest increase in price since 2017. However, it is clear that all wood fuels became more expensive in 2022.

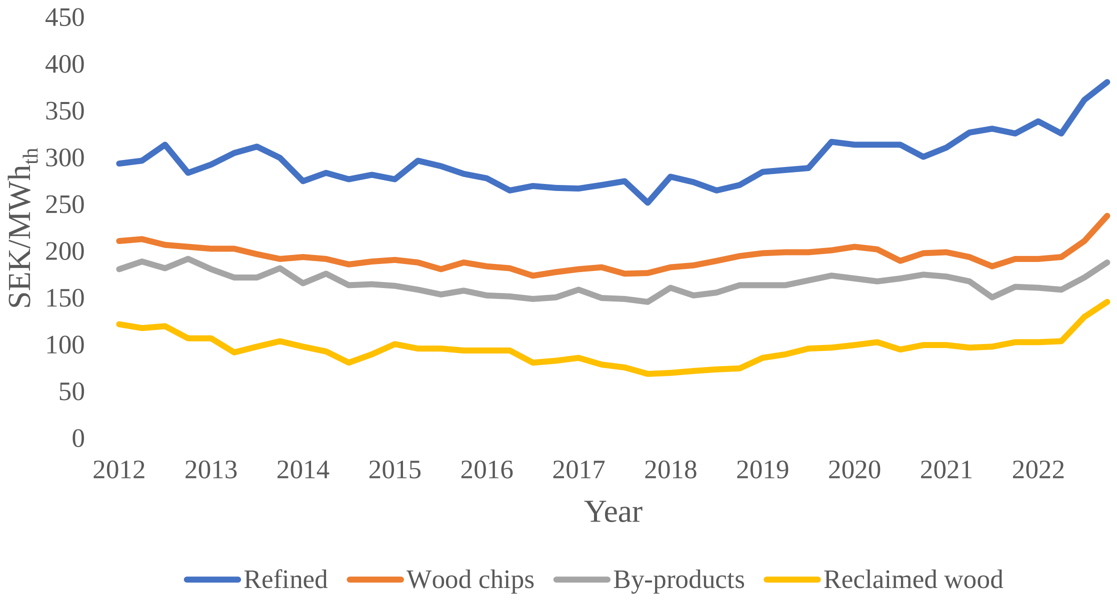

Figure 9. Prices for wood fuels used in heating plants 2012-2022, without taxes [42].

The prices for fuels used in DH are expected to rise relatively strongly in the coming years, which is due to several reasons. Firstly, since Russia started its war on Ukraine, there is a rising need of other fuels to replace Russian gas and oil. This has resulted in a higher demand of biofuels. The high electricity prices in Sweden since 2021 have also resulted in more fuel being used to produce electricity. Other industries than heating and electricity production are also expected to drive up demand for biofuels [43].

7.2 Heat Demand and Heat Load

The heat demand mainly occurs in industries, housing, premises and agriculture. In industries, heat is an important component in many manufacturing processes. The main use of heat is to maintain a desired inside temperature and to prepare hot tap water. The colder the climate and the higher the desired inside temperature is, the greater the heat demand. That is why the heat demand is higher in the Nordic countries and during the winter season [44].

Heat load is the heating power that provides the heat supply that will meet the customer's heat requirements. The heat load should correspond to the customer's heat requirements over a long period. If the heat load is lower than the heat demand, the system's delivery conditions will not be met, and the customer's indoor temperature will decrease. If the heat load is higher than the momentary heat demand, the heat can be stored for a short period of time [44].

The seasonal variations in the heat load exist simply because it is colder in the winter than in the summer. In Sweden this means that the heat demand is concentrated to early autumn to late spring. These variations can be seen in Figure 10, where the heat load for the DH system in Helsingborg during 2010 is presented [44]. This heat load pattern also represents the typical Swedish DH system [45]. There are also daily variations in the heat load, and they depend on human behaviour and regular weather variations [44].

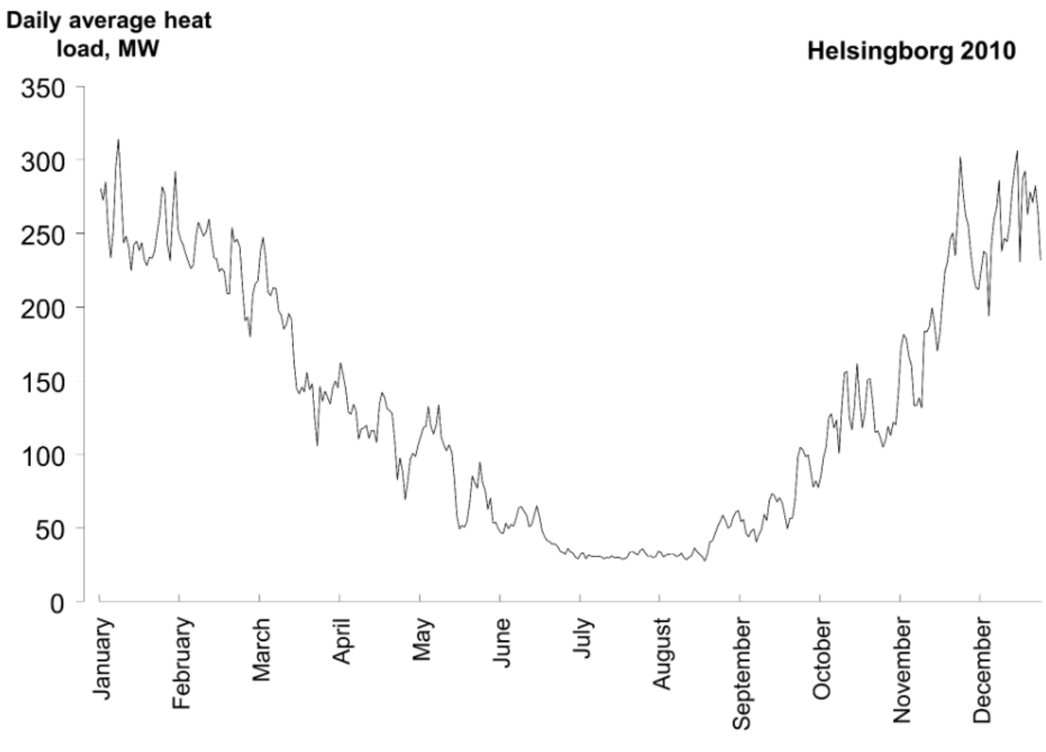

Figure 10. Daily average DH heat load for Helsingborg 2010 [44].

Figure 11 below illustrates schematically how the distribution of different loads looks in a DH system. It can be seen that the base load constitutes the majority of the load, approximately 60 %, while the intermediate and peak loads constitute the remaining 40 %. It is also visible that the top loads mainly occur in the winter months, namely November-March, which corresponds to approximately 3650 hours.

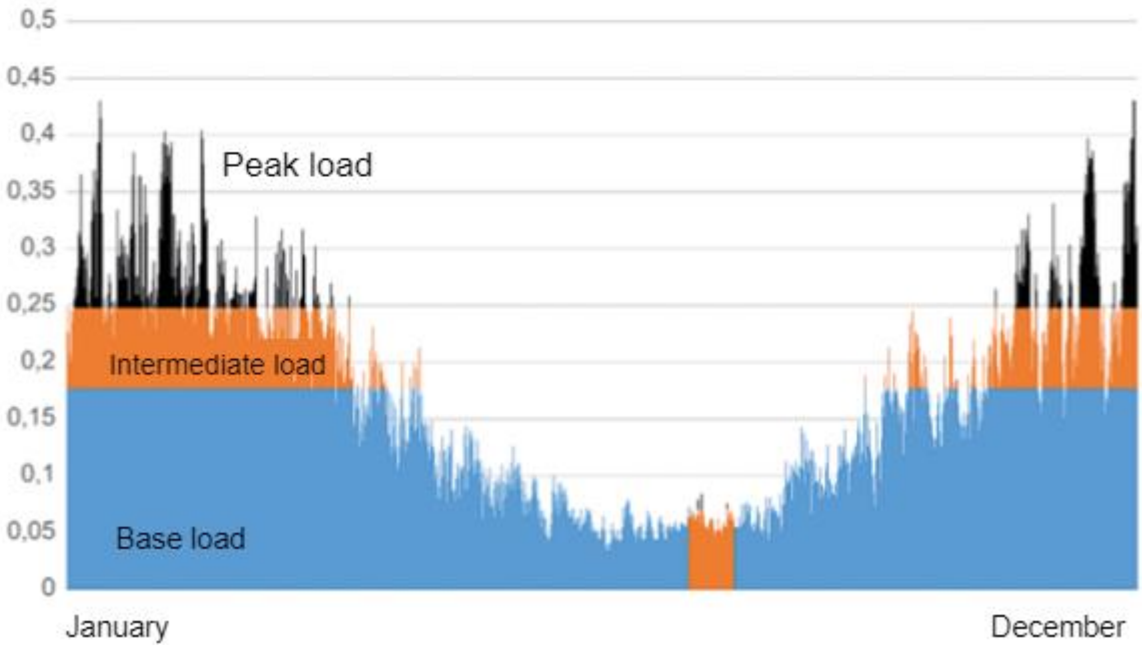

Figure 11. A schematic figure of the distribution of base load, intermediate load and peak load. The distribution may look different for different DH systems [32]. The text in the figure has been translated from Swedish.

Figure 12 below demonstrates how the marginal production costs of different types of DH systems are very high during a small portion of the year and lower for most of the year. The most expensive 3650 hours, which corresponds to the time period of November-March mentioned above, has an average marginal production cost of about 700 SEK/MWh_{th}, which is roughly 60 €/MWh_{th}. The marginal production cost includes all types of load costs – base, intermediate and peak load cost. That means that the price for the peak and intermediate loads of those 3650 hours is actually higher than 60 €/MWh_{th}, while the base load price is lower.

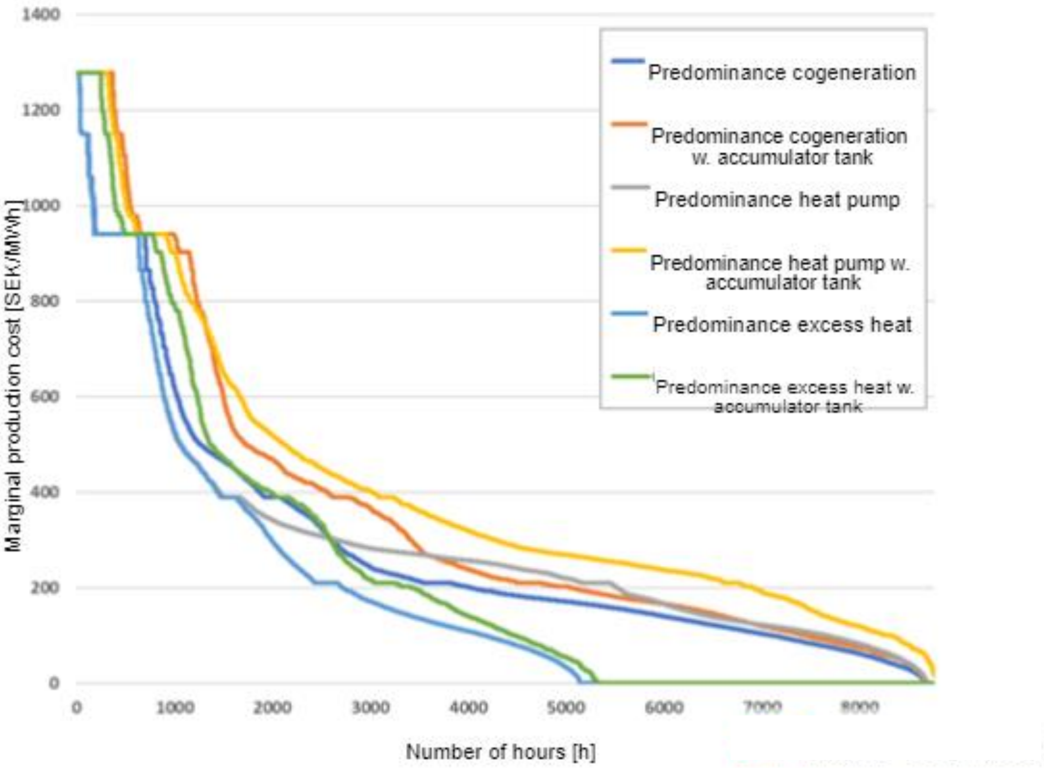

Figure 12. Marginal production cost plotted against the number of hours in a year, based on an average of 2015-2017 [40]. The text in the figure has been translated from Swedish.

8 Competitors

There are other alternative technologies available for DH companies to integrate renewable energy with their system. One example is STE, which is described below.

8.1 Solar Thermal Energy

STE is a technology which utilises solar collectors to collect energy from the sun in the form of heat. It is used for both small- and large-scale applications, for instance DH in the latter case. When STE is integrated with DH systems, it is usually in the form of bigger constructions, either as ground based solar collector fields or on top of large public buildings. Furthermore, the collectors are often connected to a thermal heat storage, in order to boost profits. There are many examples of large-scale systems where STE is integrated with DH in Sweden [32].

8.1.1 Profitability for Solar Thermal Energy in Sweden

Figure 13 below demonstrates how STE cannot always be profitably integrated with DH systems – it depends on the structure of the DH system. The green curve represents systems with many facilities including waste heat and/or waste incineration, while the blue and orange curves represent systems with few hot water boilers being powered by refined wood fuels. An investment in STE in systems with many facilities would struggle to be profitable while there is a bigger chance in the other systems. For an investment to be profitable, the lifecycle cost of heat (LCOH) for STE should be lower than the marginal cost for the DH system. Looking at Figure 13, that means that there are hours where STE is competitive with the orange and blue curves. There are quite many hours during winter, approximately 40 % of the year which corresponds to roughly 3500 hours, when STE is 80 €/MWh_{th} cheaper to produce than DH systems included in the blue curve. However, storage costs need to be added if the heat produced by STE is to be used during winter [32].

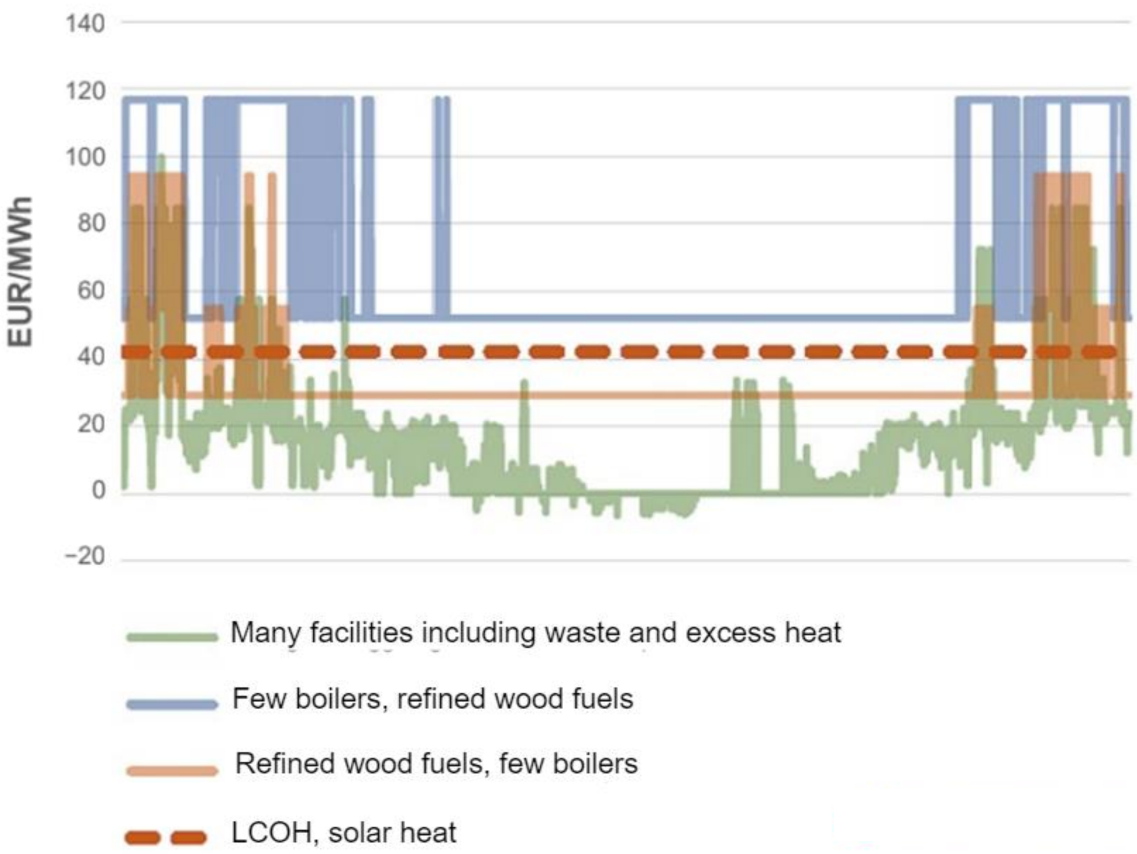

Figure 13. Marginal costs for DH production in three systems and lifecycle cost of heat for STE over a year. The green line represents a system with many facilities. The blue and orange lines represent two different systems with refined wood fuels and few steam boilers [32]. The text in the figure has been translated from Swedish.

9 Economics

In order to determine if a business case will be profitable or not and to be able to find the most sensitive economical parameters, different investment calculation methods are available. These are described below.

9.1 Net Present Value

The net present value (NPV) method takes all revenues, expenses and capital costs, as well as the timing of them, related to an investment into account. All future cash inflows and outflows are added together and discounted to the present day to account for the value of money changing. The idea behind it is to determine, among other things, the value of a new venture [46]. It is calculated by using the following equation:

$$NPV(i,N,R) = R\left(\frac{1-\left(\frac{1}{1+i}\right)^{N+1}}{1-\left(\frac{1}{1+i}\right)}\right),\ i \neq 0 \tag{1}$$

where R is constant cash flow, N the number of periods and i the discount rate.

9.2 Internal Rate of Return

The internal rate of return (IRR) is the compound rate of return that you expect to earn each year in an investment. In other words, it is the average annual growth of the investment during its lifetime, which means a high value is usually preferred. It is a good way to compare different investments to each other to see which is more profitable [47].

9.3 Payback Time

Payback time is another way to compare investments to each other. It is a measurement of how long it takes to regain an investment, based on cash flows. However, it does not measure the profitability of an investment or the risk it comes with. Because different projects may come with different risks despite having the same payback time, it may be a good idea to also look at the IRR when evaluating an investment [48].

10 The Operating Strategy

The aim of this section is to describe the operating strategy of the system and how to best utilise the electricity from the PV park and the grid. The first step for the system, which is described in Figure 1 (in section 2), is to convert electricity into heat. To be able to determine when to use electricity from the solar park, the PV park production is compared to the local grid capacity each hour. If the solar park produces more than what the grid is capable of receiving, the excess electricity is sent to the P2H unit. The excess electricity would otherwise be wasted as it is not possible to sell it to the grid. Before any electricity is sent to the P2H unit, we check if there is a DH heat demand that hour or if there is space for the produced heat in the storage. If the storage is full and there is no heat demand that hour, no electricity will be sent to the P2H unit. Otherwise, the heat is sold directly to the DH network or stored. We also check what the spot price is currently at that hour and compare it to a spot price limit we have set in advance, to see if we either want to use electricity from the PV park, buy from the grid or sell to the grid. This operating strategy is illustrated more clearly in Figure 14 below.

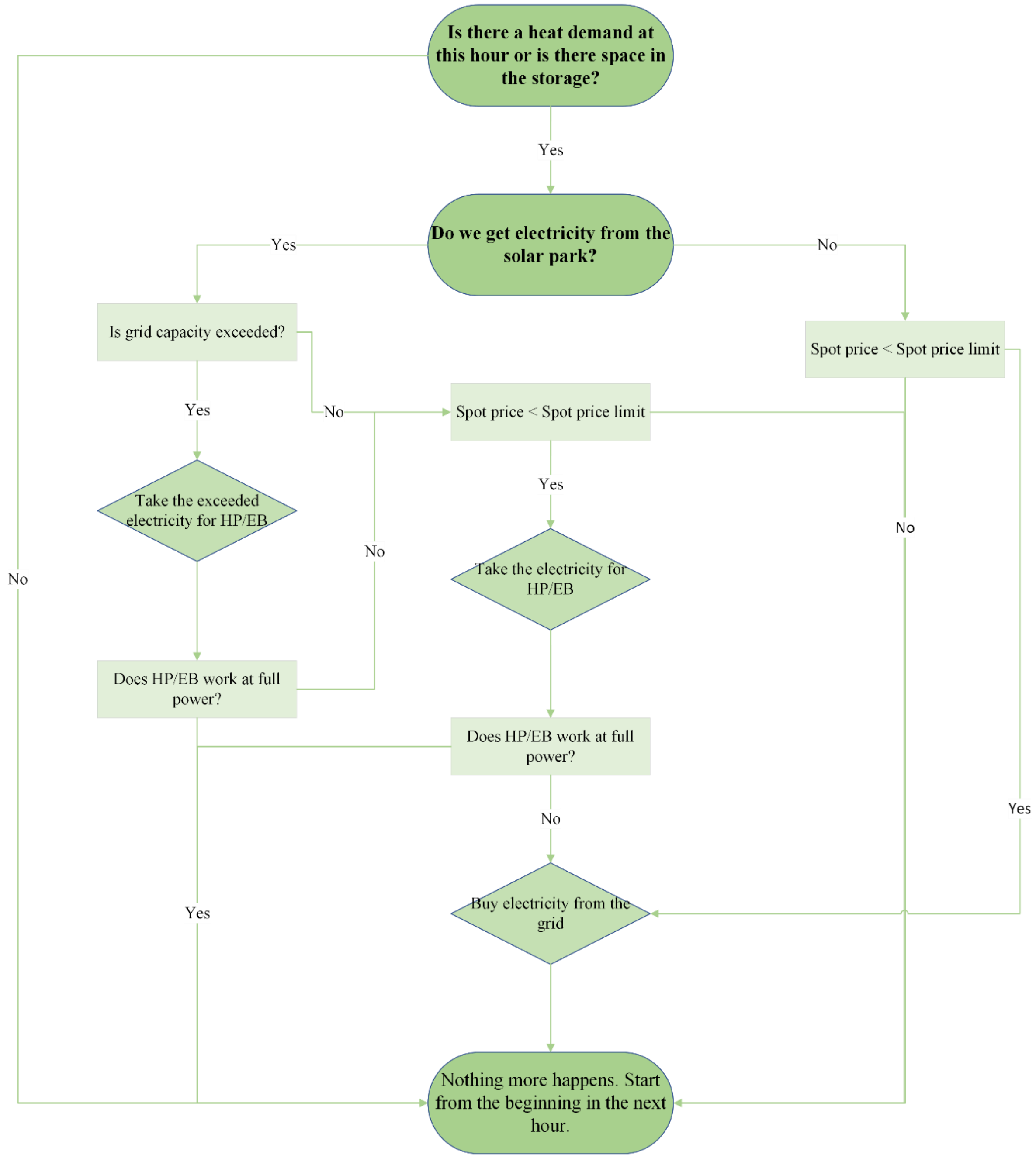

Figure 14. Decision making flow chart part 1.

The second step of the system is to see when the heat from the P2H unit is sent directly to the DH network or stored in the seasonal storage. In this step we also look at when heat is discharged from the storage, which is determined by looking at the heat demand for each hour. If there is a heat demand at the current hour and the P2H unit is producing heat, the heat will be sent straight to the DH network. If there is a heat demand but no heat coming from the P2H unit, the heat is taken from the storage. If, on the other hand, there is no heat demand, but we still get heat from the P2H unit, the heat is sent to the storage for storing. This is illustrated more clearly in Figure 15. Decision making flow chart part 2.Figure 15 below.

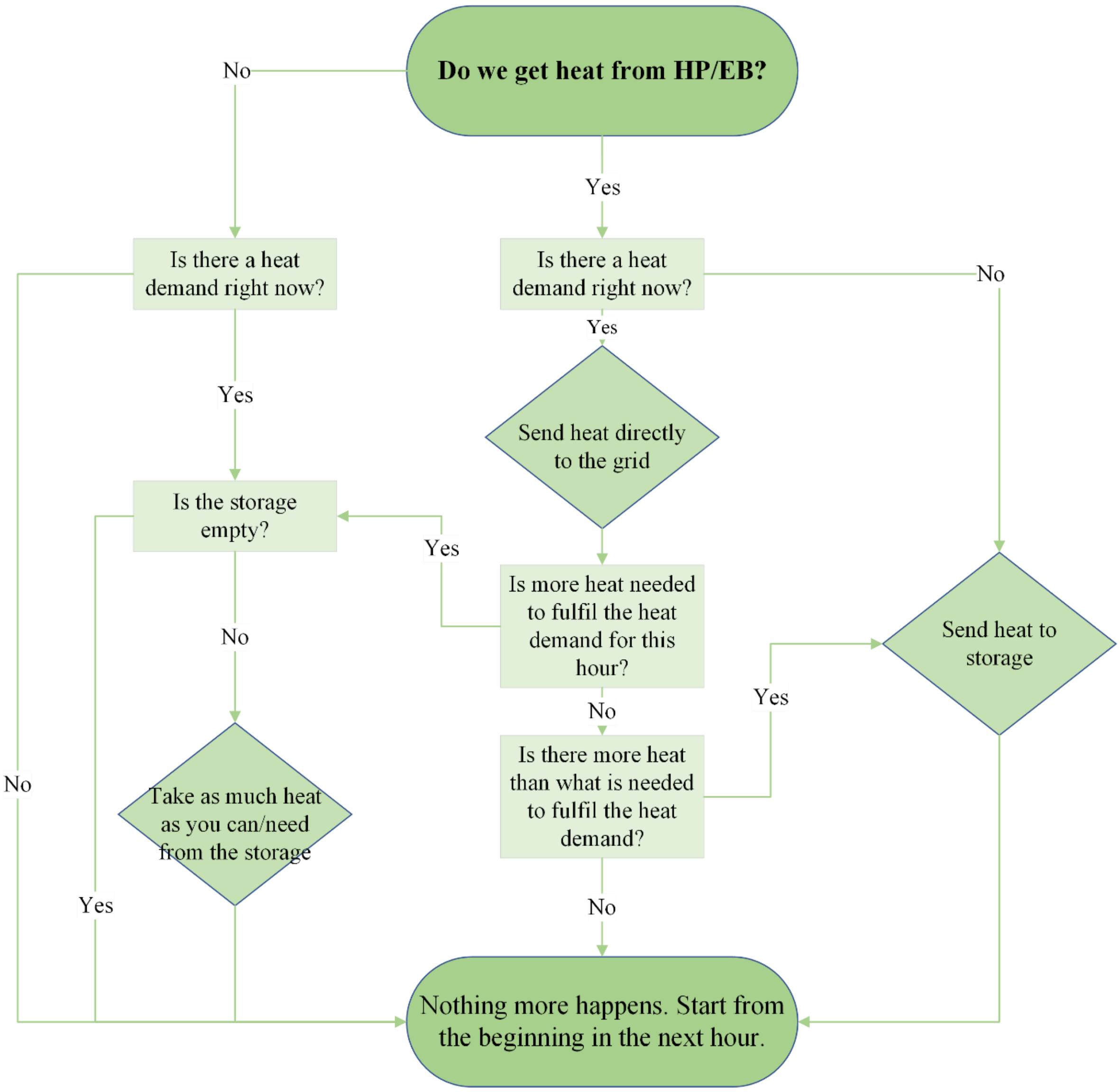

Figure 15. Decision making flow chart part 2.

These flow charts are based on how the system would work in reality, where we would have to check if there is space in the storage before being able to produce heat. In our Microsoft Excel model, which will be introduced in section 11, we will however not take that step into account. Instead, we will produce heat when there is excess electricity available or the spot price limit allows it. Either way, we will only send as much electricity to be converted to heat as we can take care of, either by sending it directly to the DH network or to the storage.

10.1 Choice of Storage Technology

Different storage techniques have been studied, and one can see that the immature techniques (latent storage and thermochemical storage) have a much higher investment cost than most of the mature techniques (sensible storage). From the sensible storage techniques, accumulator tanks were not suitable for seasonal storage, which is why we do not discuss them here.

The aquifer systems have a low investment cost compared to other technologies, but the discharge temperature is very low and can vary between (8-28) °C, which is much lower than what is required in DH systems. This type of storage can therefore be more suitable in district cooling systems. Rock beds are associated with a large investment cost and therefore have difficulties to compete against other seasonal storage technologies with a lower investment cost. Borehole storage has the advantages of a low investment cost and that it is placed underground, so that the space above ground can be used for other things. The discharge temperature varies between (20-55) ℃ for a borehole storage, which is low compared to the flow temperature in district heating systems. The efficiency for real installations of borehole storages varies between (45-63) %.

Pit heat storage has generally a higher investment cost than both borehole storage and aquifer systems, but the energy density is much higher as well. The reason why this type of storage should be suitable for a district heating system is since the operating temperature can be between (10-90) ℃ and it has an efficiency between (64-86) %. There are also pit heat storages that are used for both short-term and long-term storage, which can improve the economic benefits. One problem with pit heat storage is that it requires a lot of space, which can be difficult in a built environment.

Since both latent and thermochemical heat storages are under development and do not exist in the heating districts today, we have chosen to go with a more mature technology. We have therefore chosen to proceed with pit heat storage as a storage option. The investment cost for the storage is chosen as 0.445 k€/MWh_{th}, as it is the actual investment cost for an existing pit heat storage in Denmark with a size that is deemed as reasonable for this project. Also, it was on the lower end of the cost spectrum that was presented in section 6, but close to the average price. This cost will however also be tested in the sensitivty for the P&L statement in order to see if a change in CAPEX would affect the results in a significant way. The efficiency is assumed to be 85 %, which is on the higher end of the spectrum that was stated in section 6. This is a quite optimistic assumption, but the choice was made as it was assumed to be necessary for the system to be profitable.

10.2 Choice of P2H Technology

One purpose of this thesis is to determine the most promising P2H technology for our system, which is why we will compare the HP and EB. Out of the financial data listed for the two different HP technologies, the excess-heat one is what we will use in our model. This choice was made since it is cheaper than the air-source HP, but still much more expensive than an EB, so we chose the most competitive option.

Regarding the financial data, there was very limited updated data available. The numbers stated in section 5 (Table 2 and 3) are however deemed reliable, due to the source being a Danish agency, and are assumed to be representable for the Swedish market as well. In order to cover for this potential source of error, the CAPEX cost for the technology used in the P&L statement will be tried in a sensitivity analysis. By determining the sensitivity, the impact of the potential error can be identified.

11 The Model of the System

In order to test our system in different ways, and to develop a deeper understanding of what affects it, we built a model in Microsoft Excel. It is based on our system as described in sections 2 and 10 and is designed in such a way that we can compare the heat production cost, P2H capacity, storage capacity and addressed heat demand. To start with, the source of electricity which the P2H unit utilises was determined to be a mix of grid electricity and PV park electricity. The amount of electricity that would be used by the P2H unit depends on three factors: spot price, spot price limit and grid capacity. The grid capacity is limited for the investigated city and DH system, but the other two factors will affect the results.

The aim of the model is to allow us to dimension a system based on a certain DH heat demand as well as some other set parameters. This results in knowledge of when to buy or use electricity, what capacity the P2H unit needs to have, how big the storage needs to be and ultimately the total heat production cost. From this, we can discuss whether a HP or EB is the optimal choice for the system. The model also allows us to investigate which parameters affect the results the most.

One big difference in our Excel model compared to how it is described in section 10 is that the Excel model does not have a limit of how big the storage can be. This decision was made because we wanted to dimension the system based on a heat demand, so we did not want to limit the storage size from the start.

11.1 Assumptions

Assumptions have been made to identify the parameters that affect the system the most. We assume that excess heat will always be available when necessary to operate the excess heat-source HP. To gain a deeper understanding of the system, Filipstad, a city in Sweden, was chosen as an example to base a case on. Some of the data used in our model is based on conditions in Filipstad, but we stress that this is only an example. Also, we assume that the sun irradiation data used for Filipstad is applicable to other places in southern Sweden, so the results we get will be applicable on other places as well. Furthermore, we assume that SE3 and SE4 have similar spot prices and can be compared directly. Taxes for electricity production for the PV park and electricity usage, as well as costs for cables and the like is not considered in this study. To be able to make interesting comparisons, we assume that the capacity factor is defined as the used power in a year divided by the theoretical maximum available power in a year. Finally, we assume that there is always a DH company that is willing to buy the heat we wish to sell.

11.2 Parameters

The parameters we used in our Excel model are described in the following sections. They include spot prices, max heat demand, addressable heat demand, PV park capacity, grid capacity, a spot price limit, price for excess power, price for PV power below price limit, heat/power ratio, storage efficiency, date for emptying the storage, P2H electric capacity, availability and financial parameters.

11.2.1 Spot Prices

We have chosen to use spot prices for six years in our model: 2017-2019 and three forecasted years between 2024-2030, referred to as 202X, 202X-1 and 202X+1. The first years' data are based on SE3 and the later are based on SE4. The reason for that is that we only have forecast data for SE4, but Filipstad is located in SE3. The reason for looking at several years is due to the fluctuating nature of the spot prices and to show different scenarios, and the first three years were chosen as historic data to give more robust results. The years 2020-2022 were disregarded as the prices may have been compromised due to the Covid-19 pandemic and other events, and 2023 was not used as we do not have historic data for the full year yet.

The years 202X, 202X-1 and 202X+1 are based on forecasts from BayWa r.e. but are interesting to use as they could give an idea of what the results could look like in the future, when this kind of system would be constructed. The forecasts are confidential, which is why the years are not revealed. Moreover, since more renewable electricity production is expected to make spot prices more volatile in the future, it is interesting to see how the results vary compared to historic spot prices. Based on the forecast data we have had access to, the most interesting year is 202X, as it seems to be an average of the future forecasted years. The years just before and after 202X were chosen to give a good comparison. The price trend 2024-2030 seems to be an increased variability in spot prices compared to historical data, with a decreasing average price following the peak in 2022.

It should be noted that we do only use these years' spot prices as reference for what the future could look like. They are only meant to be viewed as reference price distributions, to see how different spot price scenarios could affect our results.

11.2.2 Max Heat Demand

The heat demand is based on data from Helsingborg in 2010 but can, as previously mentioned in section 7, be applied to different DH systems in Sweden. The parameter is defined as the maximum heat demand in a year, in MW_{th}, for the chosen DH system during a single hour. The heat demand is then scaled according to the ratio between the assumed and Helsingborg heat demand for each hour. The heat load curve, which was based on Helsingborg but recreated in our Excel model, can be seen in Figure 16 below. Since it is not the source data, it should not be seen as a perfect representation of the actual heat demand, but the heat load profile is similar enough to be used for a rough estimate.

The parameter was, unless otherwise mentioned, based on the annual heat demand of Filipstad. The annual heat demand of Filipstad is 48 GWh/year [49] which corresponds to 4 % of Helsingborg's demand of 1 200 GWh_{th}/year according to Figure 16 below. The max heat demand of Filipstad was then calculated as 4 % of the max heat demand of Helsingborg, which resulted in 12 MW_{th}.

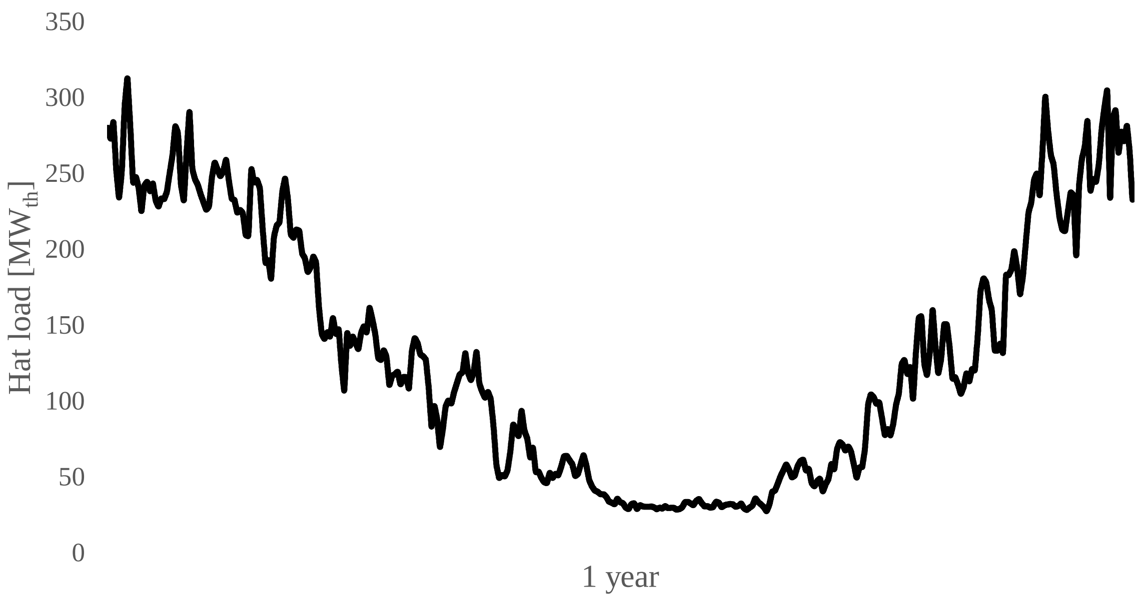

Figure 16. Interpolated heat load data for Helsingborg 2010.

11.2.3 Addressable Heat Demand

The addressable heat demand describes how much of the maximum heat demand we aim to cover. We assume we can cover the top 40 % of the heat load, since according to Figure 11, that is the percentage of the intermediate and peak load during a year. These loads correspond to the colder months of the year, namely November to March.

11.2.4 PV Park Capacity

The rated power of the solar park affects the electricity production each hour in our model. The base hourly energy data is collected from a modelled solar park in Filipstad with a rated power of 22.8 MW_e, which can be scaled in our model to test other sizes of the solar park. For our base cases, we chose to use a capacity of 20 MW_e. This size of a PV park would be the biggest in Sweden by a margin of 2 MW_e out of the already built ones. Based on experience, this range of capacity could become the standard for unused areas that are not too far from city networks. In Figure 17 below, one can see the electricity production for a PV park in Sweden with the capacity of 20 MW_e.

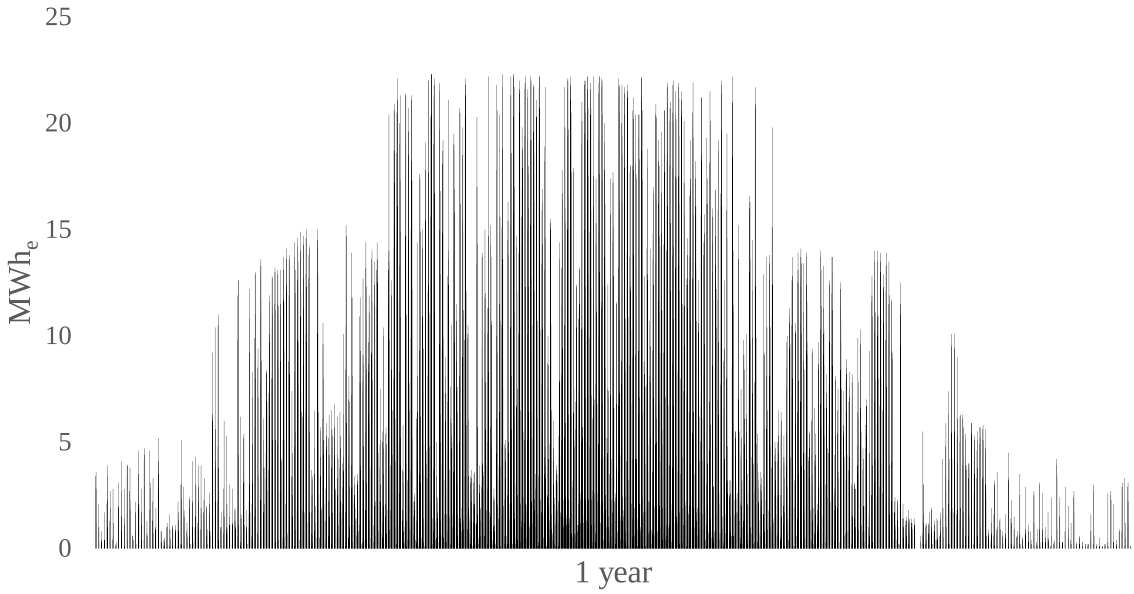

Figure 17. Electricity production over a year for a PV park in Sweden with the capacity of 20 MW_e.

11.2.5 Grid Capacity

As mentioned in section 4 of this report, the electrical grid has a limit of how much power it can handle at any given hour. This parameter affects how much electricity from the solar park will be possible to sell to the grid each hour and will determine how much of the possibly curtailed energy that will be sent to the thermal storage. For instance, if the PV park produces 20 MW_e of electricity a specific hour, and the grid capacity is 15 MW_e, that means that 5 MWh_e cannot be sold to the grid. The grid capacity varies depending on the local grid, but it is set at 15 MW_e because that corresponds to the conditions in Filipstad.

11.2.6 Spot Price Limit

Each hour when the spot price is lower than the spot price limit parameter, the produced electricity from the PV park or electricity from the grid may be used for P2H production. The parameter is varied depending on the current year and the unit is €/MWh_e. This is a major variable in deciding the operation strategy since it determines how much electricity can be bought from the PV park and grid. A higher limit means more electricity is available, but the amount depends on the spot price variation each year. The method for setting this parameter will be explained shortly.

11.2.7 Price for Excess Power

Depending on the PV and grid capacity, there may be excess power which cannot be sold to the grid due to too high electricity production or too low power grid capacity. When this is the case, the power that would have been curtailed is used by the P2H unit, and it has a different price tag than electricity in other situations. The price is fixed for each MWh_e and is set at 15 €/MWh_e, which we thought was a reasonable starting point and was a first guess based on the average spot prices in our available data. This can however be alternated in future works.

11.2.8 Price for PV Power below Price Limit

The cost of the heat production when using produced electricity by the PV park while the current spot price is lower than the PV spot price limit is assumed to be less than if the electricity would be bought from the grid. It is defined as a percentage of the current spot price and is set at 75 % of the spot price. This was a first guess based on that the PV park should still get a share of the profits from the electricity but can also be tested in future works.

11.2.9 Heat/Power Ratio

This parameter depends on the P2H technology. For the HP, the ratio is the COP, in this case fixed at 3.5. For the EB, it is set at 0.98, in other words the efficiency. This determines how much of the used electricity will be turned into heat. These numbers are based on the data in Table 2 and 3.

11.2.10 Storage Efficiency

The storage efficiency determines how much of the heat which is fed into the storage is "recovered" when retrieving it for use in the DH system. The storage technology used is pit heat storage and the efficiency parameter is set at 85 %.

11.2.11 Date for Emptying the Storage

The seasonal storage should be empty in time for summer, in order to maximise the amount of cheap electricity being used to produce heat. This is due to the solar park producing the most electricity during this time, as well as the spot prices being on the lower end. At the same time, the heat demand is much lower during summer. Therefore, the thought behind this whole system is to store the cheap energy for when it can be sold at a higher price, meaning when the heat demand is higher. A higher heat demand means that the DH companies will have to use more expensive fuels to produce heat in order to cope with the spike in demand, which is when we wish to sell our produced heat. The parameter is set to the end of March, when the heat demand starts to decrease, and the PV production starts to increase. If not all heat from the storage has been used after the winter, it would mean that the heat would stay in the storage the following year in reality and take up space from newly produced heat, and the storage capacity is not correct.

11.2.12 P2H Electric Capacity

This parameter is equivalent to the rated power of the P2H unit, in other words the maximum amount of input electric power the unit can handle, measured in MW_e. For the case of Filipstad, it depends on all the other parameters and is dimensioned based on them in order to fulfil the heat demand.

11.2.13 Availability

The availability of the P2H unit accounts for downtime for maintenance. This parameter is assumed to be the same for both the HP and EB and is set at 98 %.

11.2.14 Financial Parameters

Some financial parameters have been defined in order for us to be able to determine the heat production cost of the system. These parameters can be found in Table 5 below. All the O&M costs are based on experience by BayWa r.e. from earlier projects. The HP CAPEX cost was based on an excess heat-source HP, since it was the cheapest option of the two options.

Table 5. Financial parameters used in the Excel model.

Technology	CAPEX [k€/MW_{th}]	O&M [% of CAPEX/year]
HP	570	2.5
EB	140	2.0
Storage	0.445	1.0

11.2.15 Fixed Parameters

When producing the results, some parameters in the Excel model were fixed for every case, unless stated otherwise, as seen in Table 6 below. Others were varied and are specified for each case.

Table 6. Fixed parameters used in the Excel model.

Parameter	Value
PV max capacity [MW_e]	20
Heat max capacity [MW_{th}]	12
Addressable heat demand [%]	40
Grid capacity [MW_e]	15
Price for excess power [€/MWh_e]	15
Price for PV power below limit [% of current spot price]	75
Storage efficiency [%]	85
Date for starting to fill the storage [hour]	2000

11.3 Calculating the Heat Production Cost

We wanted to calculate the heat production cost for the P2H in order to have a good way to compare the results of the trials. This includes investment and operating costs for both the P2H technology, the storage technique and power costs to get a sense of the total cost. To do this, the NPV of the CAPEX, O&M and power costs were calculated, using a discount rate of 5 % and a lifetime of 25 years. Finally, costs were added together and divided by the number of delivered MWh_{th} to compute a total heat cost for each P2H technology. For each scenario, this calculation was based on just one year of spot prices, PV production and heat production, which is then considered as the reference average year for a 25-year period of operation. Different years of historical and forecast spot price data were considered in different scenarios. The heat cost breakdown allowed us to get a visual representation of which costs were the largest.

11.4 Setting the Spot Price Limit

As explained previously, the spot price limit determines at what hours the P2H unit is ready to receive electricity. We needed to determine the optimal spot price limit in terms of heat production cost for the P2H technologies, meaning we wanted to see what price limit results in the lowest heat production cost. This was accomplished by simply trying different limits in a span of (0-200) €/MWh_e with steps of 5 €/MWh_e, using the fixed parameters. This produced a graph as can be seen in Figure 18 and Figure 19 below, and the lowest heat production cost, without storage cost, determined the spot price limit. For 2019 that means that the optimal price limit was 55 €/MWh_e for the HP and 30 €/MWh_e for the EB, no matter how small or large the capacity of the P2H unit. For 202X the optimal price limit was 110 €/MWh$_e$ for the HP and 35 €/MWh$_e$ for the EB. These graphs and calculations were generated for each trialled year, as the heat production costs vary according to the spot prices, and they can be found in Appendix A. The production costs are also compared to the capacity factor in order to see how much of the year the P2H unit is running.

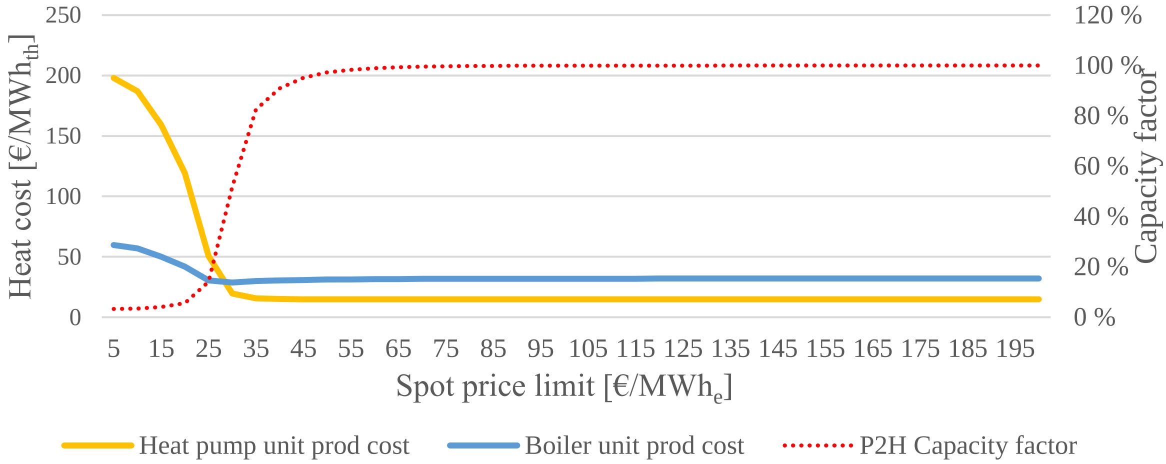

Figure 18. Heat production cost and capacity factor for a HP and an EB compared to the spot price limit for the 2019 scenario. The HP heat production cost is the cheapest at a high capacity factor while the heat production cost for the EB is cheapest at a low capacity factor. The optimal price limits are relatively close for the two P2H technologies.

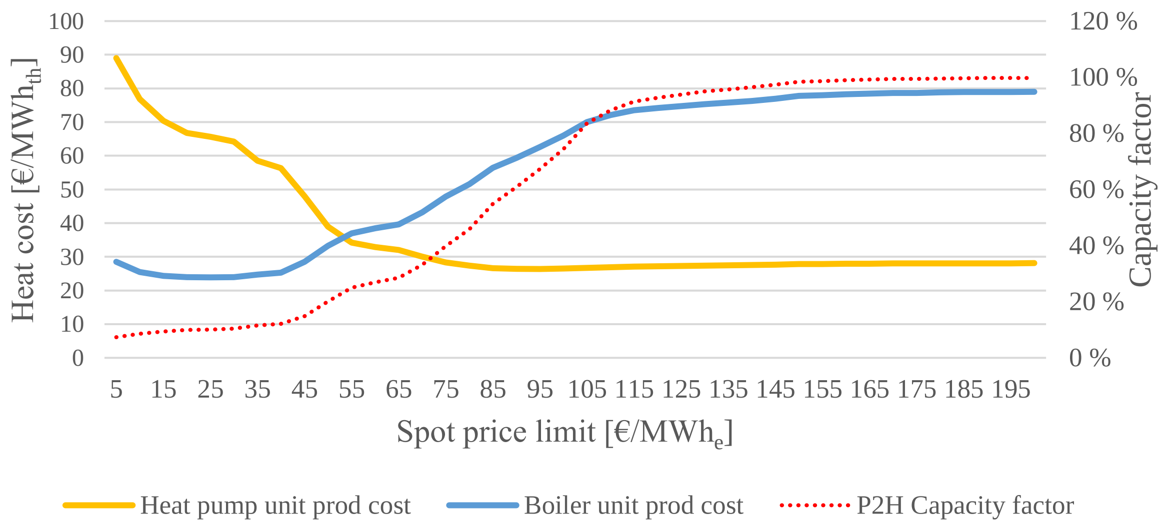

Figure 19. Heat production cost and capacity factor for a HP and an EB compared to the spot price limit for the 202X scenario. The heat production cost for the HP is the cheapest at a high capacity factor and high price limit, while the heat production cost for the EB is cheapest at a low capacity factor and low price limit.

11.5 Determining the Source of Electricity

We wanted to test which source of electricity would be the cheapest to use for the P2H technology. To do this, we tested using only PV electricity, only electricity bought from the grid and finally combining the two approaches. We tried this for both the 2019 and 202X spot price distributions and used the optimal spot price limits as previously described. To be able to analyse the results, we examined the heat production costs (including storage), amount of electricity from each source, heat production, amount of the produced heat going directly to the storage, electricity compound price and the capacity factor.

11.6 Case: Filipstad

In order to get a realistic view of how this kind of system would work, and if the HP or EB is the best choice, we decided to conduct a small case study. Therefore, the DH heat demand was based on the annual demand of Filipstad. The next step was to dimension the P2H units, from the criteria of a good storage solution. We defined a good storage solution as when the storage was empty, or nearly empty if 100 % of the heat demand was not yet fulfilled, when the date for emptying the storage occurred. This would make sure that no energy would be wasted. An example of this can be seen in Figure 20 below. The optimal solutions for the P2H technologies for both the 2019 and 202X scenarios were examined this way, with the spot price limits set as described earlier.

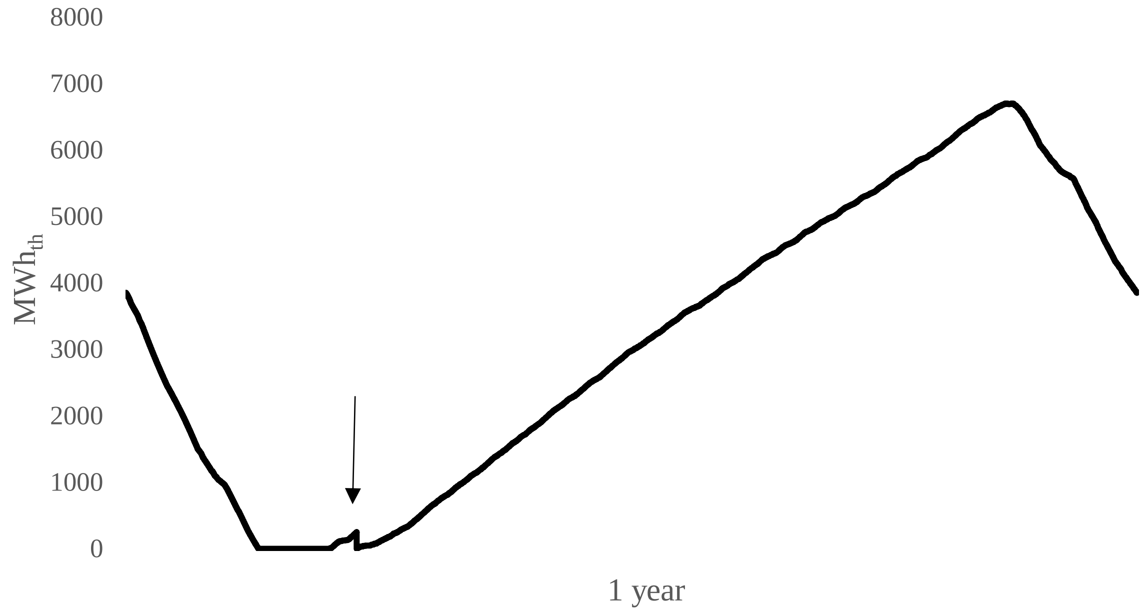

Figure 20. Storage levels for the HP for 202X scenario. The arrow indicates when the storage is set to be emptied.

11.6.1 Sensitivity Analysis

We analysed some different scenarios in order to further deepen our understanding of the system. An overview of the different cases along with a brief description can be found in Table 7.

Table 7. The different cases when analysing the Filipstad solutions.

Case	Description
1	Comparison of the best solutions for each P2H technology for six years: 2017, 2018, 2019 (base case), 202X-1, 202X and 202X+1.
2	Comparison when PV capacity was made to vary between 15 MW_e, 20 MW_e (base case) and 25 MW_e. Completed for both the 2019 and 202X scenarios. The P2H capacity was set at the optimal level for each year.
3	Comparison when the addressable heat demand was made to vary between 30 %, 40 % (base case) and 50 %. Completed for both the 2019 and 202X scenarios. The P2H capacity was set at the optimal level for each year.

In case 1 we chose to look at three historical years, 2017-2019, and three years in the future, between 2023 and 2030. The reason why we chose not to use the years 2020-2022 was because the spot prices were affected by Covid-19 and other events, and 2023 was not used since we did not have historical spot prices for the whole year.

The purpose of case 1 is to show how the capacity of the P2H unit and the heat production cost varies between different years. To achieve the best P2H capacity we dimensioned it in the same way as before in order to get a good storage solution. Case 2 and 3 are meant to illustrate how the heat production cost changes when more and less PV electricity is available, as well as when the addressable heat demand is lower and higher. This also allows us to get a deeper understanding of the difference between the different years' circumstances and how they affect the results.

11.7 Profit and Loss Statement

A simple P&L statement was made to find out the IRR and payback time for some specific cases which were deemed most interesting, to get a better view of whether a system like this is viable as a business case. In order to carry out the necessary calculations, a base heat sales price was set at 80 €/MWh_{th}, and it was assumed to be an attainable price from the available data. This price was set based on Figure 4 and Figure 5 and was thought to be a compromise between the two. The other parameters can be found in Table 8 below.

Table 8. Parameters used in the P&L statement.

Parameter	Value
Balance of payments, piping & pumps, civil works [% of equipment cost]	10
Project development costs [% of construction costs]	5
Contingencies [% of CAPEX]	5
Insurance [% of CAPEX/year]	0.8
Miscellaneous [% of operating costs]	5
General and administrative expenses [% of sales]	3
Income & deferred taxes [%]	25

11.7.1 Sensitivity Analysis

A sensitivity analysis was performed on the P&L statement as well, to see which parameters are the most sensitive. The sales price, storage CAPEX, P2H CAPEX and power costs were all varied for two cases. The power cost in this case was a weighted average of the cost of the different electricity sources for the different cases.

12 Results

The results chapter of this report is structured as follows; first some general results regarding which electricity sources to use in the model, then some specific results for the case when we use Filipstad as an example and a sensitivity analysis based on Filipstad. Finally, a P&L statement is presented as well as a sensitivity analysis based on it.

12.1 Primary Results

The first case consisted of comparing the heat production cost for the HP and EB when using electricity from different sources: when using only PV electricity, only grid electricity and finally when using both. This is done without caring for fulfilling the heat demand as we only want to examine how the different options of electricity sources affect the heat production cost for each P2H technology. Since we do not want to compare the results between the HP and EB at this point, their respective P2H capacity is set at 3 MW_e, and the spot price limit was set for the optimal levels for 2019 and 202X as can be seen in Figure 18 for the 2019 case and in Figure 19 for the 202X case.

The results are found in Table 9 for the 2019 case and in Table 12 for the 202X case. In Table 10 and 11, the amount of electricity from each source is shown for the HP and EB for the 2019 case. In Table 13 and Table 14 the same is shown but for the 202X case. Figure 21, Figure 22, Figure Figure 23 and Figure 24 show the cost stacks for the HP and EB for both scenarios.

Table 9. Heat production cost with electricity from different sources for data in the 2019 scenario. P2H capacity 3 MW_e.

Technology	Heat production cost – only PV [€/MWh_{th}]	Heat production cost – only grid [€/MWh_{th}]	Heat production cost – both PV and grid [€/MWh_{th}]	Price limit [€/MWh_e]
HP	74.4	58.8	58.0	55
EB	90.8	77.4	73.5	30

As can be seen in Table 9 above, the cheapest alternative is when the P2H unit gets electricity both from the PV park and from the grid. The difference is greater for the EB than for the HP (3.9 €/MWh_{th} compared to 0.8 €/MWh_{th} difference). Overall, the heat production price for the HP is cheaper than for the EB.

The compound power price in Table 10, 11, 13 and 14Table 14 below is the weighted average price for the different sources of electricity (excess power, power from PV park and power from grid). The electricity from the PV park in the same tables includes the excess power as well, stated in brackets.

Table 10. Amount electricity from each source for the HP in the 2019 scenario. P2H capacity 3 MW_e.

	Source of electricity - only PV	Source of electricity - only grid	Source of electricity - both PV and grid
Electricity from PV [MWh_e] (excess power)	8 300 (800)	0	8 300 (800)

Electricity from Grid [MWh_e]	0	25 200	16 900
Electricity total [MWh_e]	8 300	25 200	25 200
Heat production [MWh_{th}]	28 900	88 100	88 100
Heat to storage [%]	96	92	92
Compound power price [€/MWh_e]	30.3	37.2	34.9
Capacity factor [%]	31.5	95.7	95.7

In Table 10 it can be seen that the amount of MWh_e sent from the PV park is much lower than the amount sent from the grid. This means that the capacity factor as well as the amount of heat produced are much lower when only taking electricity from the PV park than in the other two cases. The table also shows that the compound power price is lowest in the case with only electricity from the PV park and highest with only electricity from the grid.

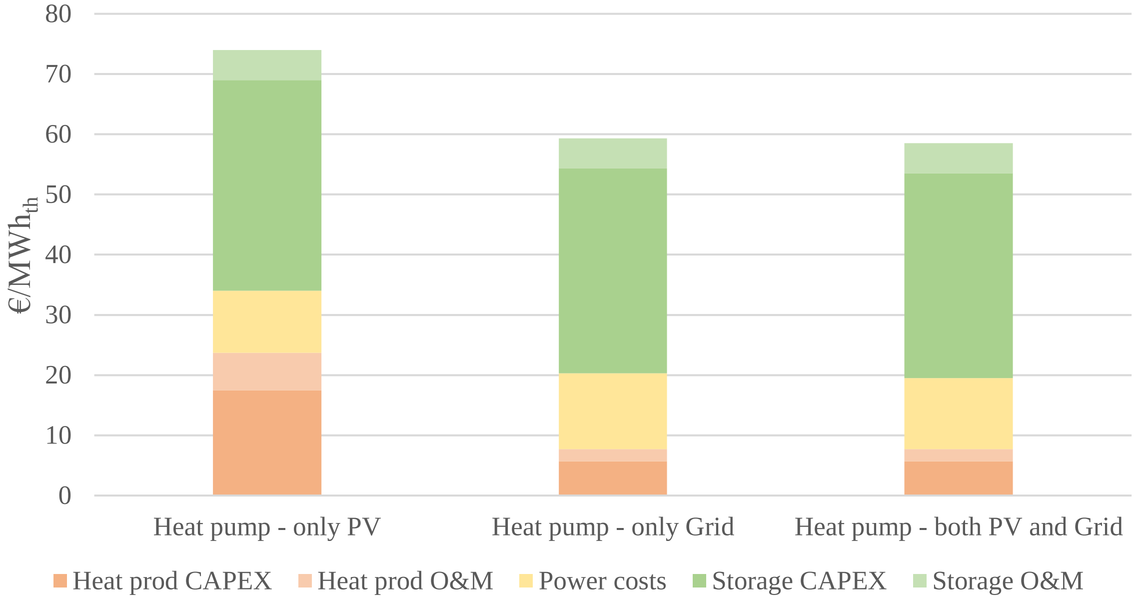

Figure 21. Cost stacks for the HP with different sources of electricity in the 2019 scenario. P2H capacity 3 MW_e.

In Figure 21 it can be seen that the CAPEX and O&M costs for the heat production are much higher in the case with only electricity from the PV park, while the power cost is more expensive in the other two cases. The CAPEX and O&M costs for the storage are almost the same in all three cases.

Table 11. Amount of electricity from each source for the EB in the 2019 scenario. P2H capacity 3 MW_e.

	Source of electricity - only PV	Source of electricity - only grid	Source of electricity - both PV and grid
Electricity from PV [MWh_e] (excess power)	1 600 (800)	0	1 600 (800)
Electricity from Grid [MWh_e]	0	3 300	2 300
Electricity total [MWh_e]	1 600	3 300	3 900
Heat production [MWh_{th}]	1 600	3 260	3 900
Heat to storage [%]	99	92	93
Compound power price [€/MWh_e]	16.9	21.0	19.1
Capacity factor [%]	6.2	12.7	15.0

In Table 11 it can be seen that the amount of electricity sent from the PV park is almost half of what is sent from the grid. It also shows that half of the electricity from the PV park is excess power. The compound power price is lowest in the case with electricity only from the grid and highest in the case with electricity only from the grid.

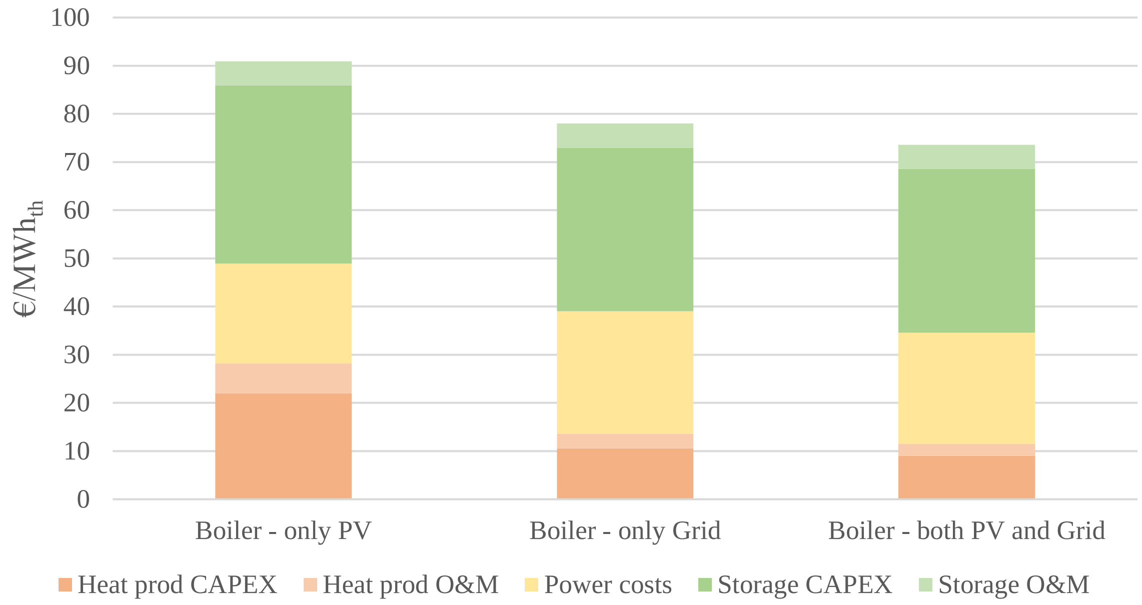

Figure 22. Cost stacks for the EB with different sources of electricity in the 2019 scenario. P2H capacity 3 MW_e.

In Figure 22 it can be seen that the CAPEX and O&M costs for the heat production is much higher in the case with only electricity from the PV park, while the power cost is a little more expensive in the other two cases. The CAPEX and O&M costs for the storage are almost the same in all three cases.

Table 12. Heat production cost with electricity from different sources in the 202X scenario. P2H capacity 3 MW_e.

Technology	Heat production cost – only PV [€/MWh_{th}]	Heat production cost – only grid [€/MWh_{th}]	Heat production cost – both PV and grid [€/MWh_{th}]	Price limit [€/MWh_e]
HP	91.6	78.2	76.0	110
EB	90.9	72.3	68.2	35

As can be seen in Table 12 above, the lowest cost alternative is when the P2H unit uses electricity from both the PV park and from the grid. The difference is greater for the EB than for the HP (4.1 €/MWh_{th} compared to 2.2 €/MWh_{th} difference). Overall, the heat production cost for the EB is cheaper than for the HP.

Table 13. Amount of electricity from each source for the HP in the 202X scenario. P2H capacity 3 MW_e.

	Source of electricity - only PV	Source of electricity - only grid	Source of electricity - both PV and grid
Electricity from PV [MWh_e] (excess power)	6 700 (800)	0	6 700 (800)
Electricity from Grid [MWh_e]	0	17 100	10 400
Electricity total [MWh_e]	6 700	17 100	17 100
Heat production [MWh_{th}]	23 400	59 900	59 900
Heat to storage [%]	97	93	93
Compound power price [€/MWh_e]	60.8	82.3	75.8
Capacity factor [%]	25.4	65.1	65.1

In Table 13 it can be seen that the amount of MWh_e sent from the PV park is much lower than the amount sent from the grid. This means that the capacity factor as well as the amount of produced heat are much lower when only taken electricity from the PV park than in the other two cases. The table also shows that the compound power price is lowest for the case with only electricity from the PV park and highest with only electricity from the grid. This is almost the same result as in the 2019 case except that the compound power price for the 202X case is much higher.

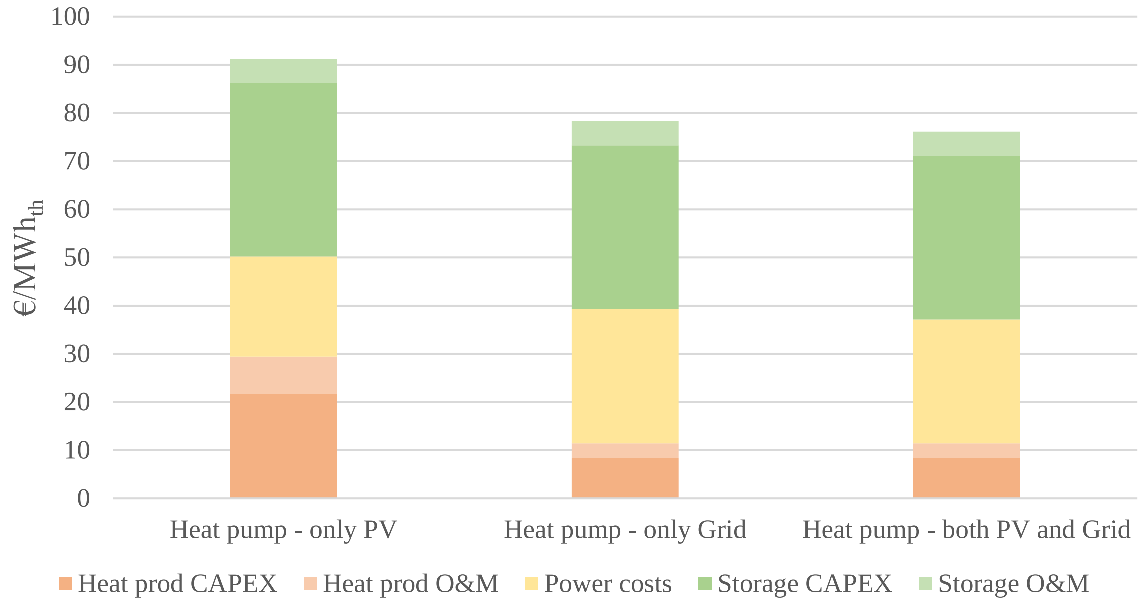

Figure 23. Cost stacks for heat production cost for the HP for the 202X scenario. P2H capacity 3 MW_e.

In Figure 23 it can be seen that the CAPEX and O&M costs for the heat production is much higher in the case with only electricity from the PV park, while the power cost is more expensive in the other two cases. The CAPEX and O&M costs for the storage are almost the same in all three cases. This result is also very similar to the result in the 2019 case, except that the overall costs are lower for that year.

Table 14. Amount of electricity from each source for the EB in the 202X scenario. P2H Capacity 3 MW_e.

	Source of electricity - only PV	Source of electricity - only grid	Source of electricity - both PV and grid
Electricity from PV [MWh_e] (excess power)	1 300 (800)	0	1 300 (800)
Electricity from Grid [MWh_e]	0	1 300	600
Electricity total [MWh_e]	1 300	1 300	1 900
Heat production [MWh_{th}]	1 300	1 300	1 900
Heat to storage [%]	96	62	75
Compound power price [€/MWh_e]	13.3	12.3	13.1
Capacity factor [%]	5.1	4.9	7.5

Table 14 shows that in this case the amount of MWh_e sent from the PV park is the same as the amount when only buying from the grid. It also shows that the amount of excess power is half of the electricity bought from the grid. In this case the compound power price is cheapest when only buying from the grid and most expensive when only buying from the PV park. The table also shows that the amount of heat going to the storage is 96 % when only buying from the grid and 62 % and 75 % in the other two cases.

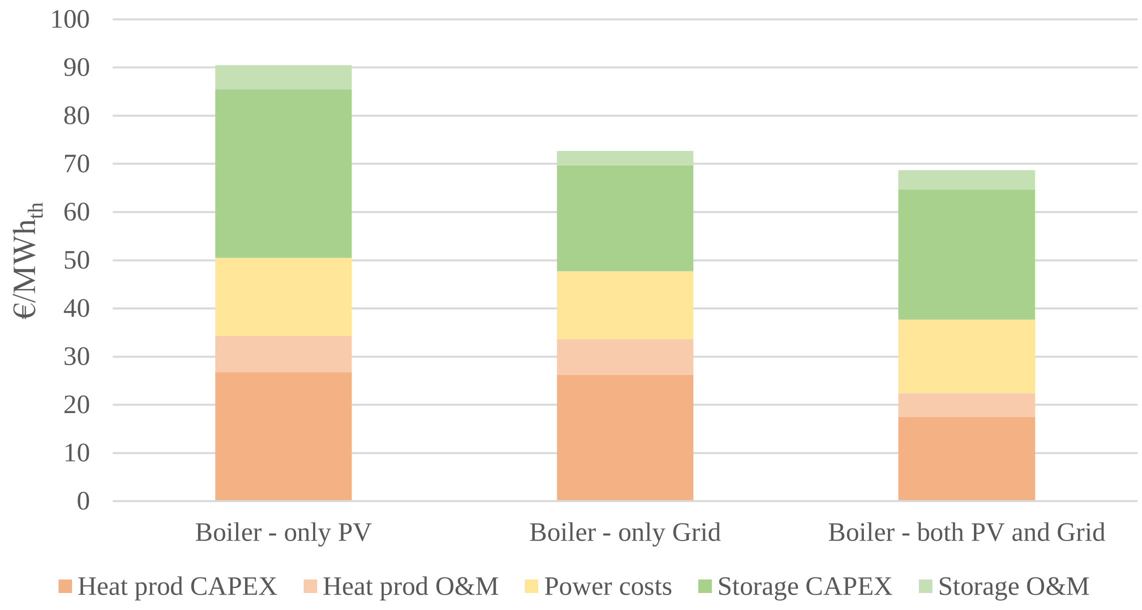

Figure 24. Cost stacks for the EB for the 202X scenario. P2H capacity 3 MW$_e$.

In Figure 24, the cost stacks for an EB for the 202X scenario are shown. It shows that the CAPEX and O&M costs for the heat production are much higher for the case when only buying from the grid and when only buying from the PV park. The power cost for all three cases is almost the same, and the CAPEX and O&M costs for the storage are higher for the case when only buying from the PV park and lower for the case when only buying from the gird.

12.2 Case: Filipstad

The results optimised for Filipstad for the 2019 scenario are shown in Table 15 and the cost stacks for the HP and the EB are illustrated in Figure 25. The results for the 202X scenario are shown in Table 16, and the cost stacks are shown in Figure 26. The annual earnings for the PV park from the sold electricity can be found in Appendix B.

Table 15. Data when optimising the system for an average price distribution similar to 2019.

P2H technology	Heat production cost [€/MWh$_{th}$]	Heat production cost without storage cost [€/MWh$_{th}$]	Capacity [MW$_e$]	Spot price limit [€/MWh$_e$]	Max storage capacity [MWh$_{th}$]	Covered heat demand [%]
HP	46.7	18.7	0.3	55	5830	90
EB	77.0	37.0	8	30	8600	94

Table 15 shows that the heat production cost, as well as the capacity of the P2H and the storage, are much lower for the HP than for the EB. The optimum spot price limits for the two P2H technologies are also shown in the table and one can see that the spot price limit for the HP is almost twice as big as the spot price limit for the EB.

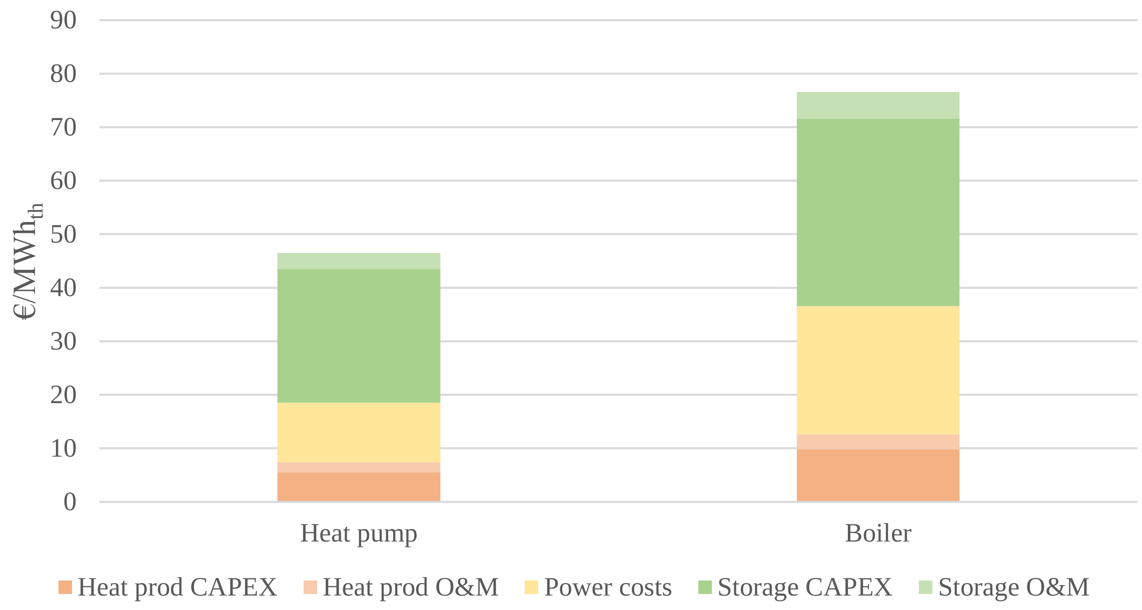

Figure 25. Cost stacks when optimising the system for an average price distribution similar to 2019.

In Figure 25, one can see the cost stacks for when optimising the system for an average price distribution similar to 2019, and it shows that the power costs and the CAPEX and O&M costs for both the heat production and the storage are higher for the EB than for the HP.

Table 16. Data when optimising the system for an average price distribution similar to 202X.

P2H technology	Heat production cost [€/MWh_{th}]	Heat production cost without storage cost [€/MWh_{th}]	Capacity [MW_e]	Spot price limit [€/MWh_e]	Max storage capacity [MWh_{th}]	Covered heat demand [%]
HP	67.3	35.7	0.45	110	6700	91
EB	110.7	72.0	35 (*)	35	6200	89

(*) The heat demand is not fulfilled with this P2H capacity, but it is unnecessary to have a bigger capacity than the PV max capacity plus the grid capacity. This is because the P2H unit cannot get more electricity for one hour than max capacity from the PV park plus max capacity from the grid.

Table 16 also shows that the heat production cost and the capacity for the P2H, for the 202X scenario, are lower for the HP than for the EB. The table shows that the EB reaches its maximum capacity of 35 MW_e and the capacity of the storage is almost the same for the two P2H technologies.

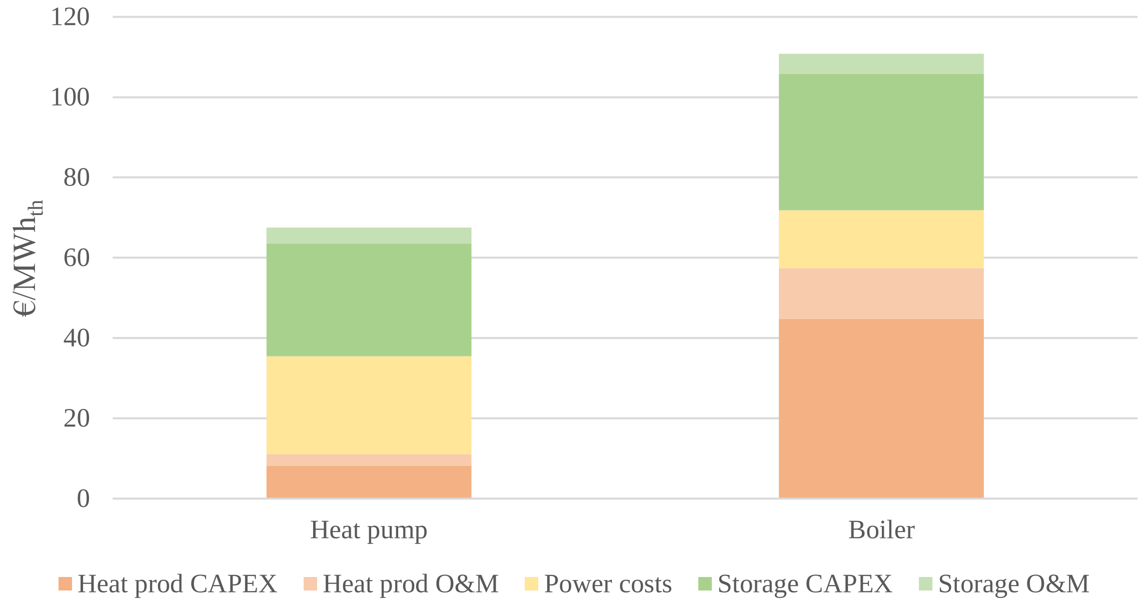

Figure 26. Cost stacks when optimising the system for an average price distribution similar to 202X.

In Figure 26, one can see the cost stacks for when optimising the system for an average price distribution similar to 202X, and they show that the CAPEX and O&M costs for the heat production are much higher for the EB than for the HP. The CAPEX and O&M costs for the storage are almost the same, but a little higher for the EB than for the HP. The power costs are on the other hand lower.

12.3 Sensitivity Analysis

The results for the best solutions each year for case 1 are shown in Table 17 and Table 18 below.

Table 17. Case 1, results for the HP.

Reference year for price curve model	Heat production cost [€/MWh$_e$]	Capacity [MW$_e$]	Spot price limit [€/MWh$_e$]	Max storage capacity [MWh$_{th}$]
2017	43.6	0.3	50	5780
2018	47.5	0.3	60	5560
2019	46.7	0.3	55	5830
202X – 1 year	75.0	0.55	140	6610
202X	67.3	0.45	110	6700
202X + 1 year	63.3	0.5	90	7410

Table 18. Case 1, results for the EB.

Reference year for price curve model	Heat production cost [€/MWh$_e$]	Capacity [MW$_e$]	Spot price limit [€/MWh$_e$]	Max storage capacity [MWh$_{th}$]
2017	62.6	2	30	6320

2018	66.1	5.5	35	4410
2019	77.0	8	30	8600
202X – 1 year	131.8	35(*)	45	5510
202X	110.7	35(*)	35	6200
202X + 1 year	67.2	13.5	25	5870

(*) The heat demand is not fulfilled with this P2H capacity, but it is unnecessary to have a bigger capacity than the PV max capacity plus the grid capacity. This is because the P2H unit cannot get more electricity for one hour than max capacity from the PV park plus max capacity from the grid.

As can be seen in Table 17 and Table 18, the capacity for the HP varies between (0.30-0.55) MW_e and for the EB the capacity varies between (2-35) MW_e. The spot price limits vary a lot for the HP, between (50-110) €/MWh_e, while it is more even for the EB (between (25-45) €/MWh_e). The heat production cost is cheapest for the HP when comparing the optimal solutions for Filipstad for the different years' price distributions, and this can also be seen in Figure 27 below. One can also see that the heat production cost is cheaper in the scenarios for 2017-2019 and a lot higher for 202X-1 and 202X. In the 202X+1 scenario, the heat production cost has decreased again and the difference between an HP and an EB is not that great anymore.

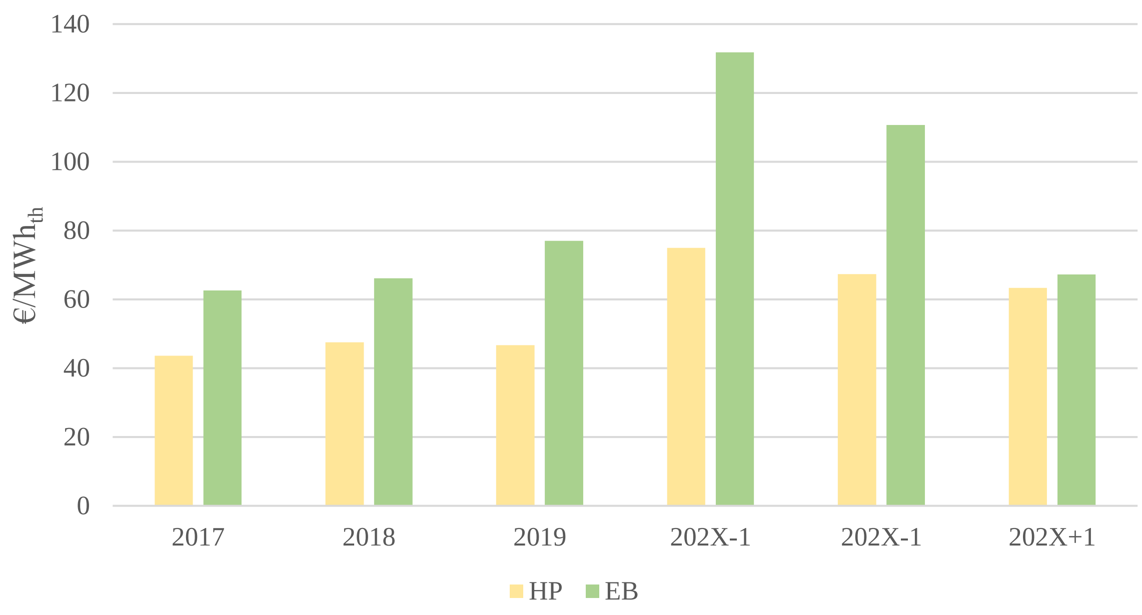

Figure 27. Heat production cost for the HP and EB for the different reference years.

The results for case 2 and 3 are found in Table 19 and Table 20 below. They illustrate that the HP option is the cheapest one in all scenarios for case 2 and 3. When changing the PV capacity between ±25 %, the heat production cost changes between +4 % to –0.2 % for the HP and ±3 % for the EB for the 2019 case. In the 202X scenario the changes are lower for the HP (between ±1 %), and a lot bigger for the EB (between –0.6 % down to –22 %). When changing the addressable heat demand between ±25 %, the heat production price is quite stable for the HP for both the 2019 and 202X cases, as it does not vary more than ±3 %. For the EB, the heat production cost is stable for the 2019 case (varies between ±2 %), but in the 202X scenario the variations are greater, ranging between –1 % and –24 %.

Table 19. Case 2, results for different PV capacities.

Reference year for price curve model		HP			EB		
	PV capacity [MW_e]	15 (-25 %)	20 (Base case)	25 (+25 %)	15 (-25 %)	20 (Base case)	25 (+25 %)
2019	Heat production cost [€/MWh_{th}]	46.9 (+0.4 %)	46.7	46.6 (-0.2 %)	79.4 (+3.1 %)	77.0	74.7 (-3.0 %)
	P2H capacity [MW_e]	0.35	0.3	0.35	9	8	7
202X	Heat production cost [€/MWh_{th}]	68.2 (+1.3 %)	67.3	66.6 (-1.0 %)	110.0 (-0.6 %)	110.7	86.8 (-21.6 %)
	P2H capacity [MW_e]	0.45	0.45	0.45	30 (*)	35 (*)	21.5

(*) The heat demand is not fulfilled with this P2H capacity, but it is unnecessary to have a bigger capacity than the sum of the PV max capacity and the grid capacity. For the base case for the EB in 202X the PV max capacity is 20 MW_e, and the grid capacity is 15 MW_e, meaning the most electricity which can be received by the EB is 35 MW_e. When the PV max capacity is 15 MW_e, the most electricity which can be received is instead 30 MW_e.

Table 20. Case 3, results for different addressable heat demands.

Reference year for price curve model		HP			EB		
	Addressable heat demand [%]	30 (-25 %)	40 (Base case)	50 (+25 %)	30 (-25 %)	40 (Base case)	50 (+25 %)
2019	Heat production cost [€/MWh_{th}]	47.7 (+2.1 %)	46.7	45.3 (-3.0 %)	75.8 (-1.6 %)	77.0	78.3 (+1.7 %)
	P2H capacity [MW_e]	0.20	0.30	0.45	4.5	8	12.5
202X	Heat production cost	68.3 (+1.5 %)	67.3	66.3 (-1.4 %)	84.3 (-23.8 %)	110.7	109.5 (-1.1 %)

	[€/MWh$_{th}$]						
	P2H capacity [MW$_e$]	0.25	0.45	0.70	12	35 (*)	35 (*)

(*) The heat demand is not fulfilled with this P2H capacity, but it is unnecessary to have a bigger capacity than the sum of the PV max capacity and the grid capacity. For the EB in 202X the PV max capacity is 20 MW$_e$, and the grid capacity is 15 MW$_e$, meaning the most electricity which can be received by the EB is 35 MW$_e$.

12.4 P&L Statement

A P&L statement was put together along with a sensitivity analysis, where we identified and compared the payback time and IRR. Most of the numbers and values were taken from our model in Excel and others were guesses based on experiences from earlier projects. The statement is based on the optimal HP solutions for the 2019 and 202X scenarios, which means a P2H capacity of 0.3 MW$_e$ and 0.45 MW$_e$ respectively.

The parameters that were varied in the sensitivity analysis in this case were the heat sales price and the CAPEX for both the storage and the P2H as well as the average power price. The heat sales price in this case is only an average of the real heat sales prices over the year. Some hours we are able to sell the heat for a higher price and some hours for a lower price. The results of the sensitivity analysis of the heat sales price can be seen in Table 21 and Table 22, and the results of the sensitivity analysis of the CAPEX can be seen in Table 23 and Table 24.

Table 25 and Table 26 show the sensitivity analysis conducted for the power price for both the 2019 and 202X cases.

Table 21. P&L and sensitivity analysis in the 2019 scenario.

Heat sales price [€/MWh$_{th}$]	Payback time [years]	IRR [%]
60 (-25 %)	14.6 (+49.0 %)	4.4 (-48.8 %)
70 (-12.5 %)	11.7 (+19.4 %)	6.6 (-23.3 %)
80 (Base case)	9.8	8.6
90 (+12.5 %)	8.4 (-14.3 %)	10.4 (+20.9 %)
100 (+25 %)	7.4 (-24.5 %)	12.1 (+40.7 %)
110 (+37.5 %)	6.7 (-31.6 %)	13.8 (+60.5 %)

Table 22. P&L and sensitivity analysis in the 202X scenario.

Heat sales price [€/MWh$_{th}$]	Payback time [years]	IRR [%]
60 (-25 %)	-	-1.5
70 (-12.5 %)	21.3 (+31.5 %)	1.2 (-64.7 %)
80 (Base case)	16.2	3.4
90 (+12.5 %)	13.1 (-19.1 %)	5.4 (+58.9 %)
100 (+25 %)	11.1 (-31.5 %)	7.1 (+108.8 %)

110 (+37.5 %)	9.6 (-40.8 %)	8.8 (+158.8 %)

Table 21 shows the changes in the payback time and the IRR, when trying different heat sales prices for the 2019 scenario. In comparison with Table 22, that shows the changes for the 202X scenario, the payback time and the IRR are a lot better for the 2019 scenario in general and in particular for the base case. The base case for the 2019 scenario has a payback time of 9.8 years and an IRR of 8.6 %, while for 202X the payback time is 16.2 years, and the IRR is 3.4 %. The changes in both the payback time and the IRR are higher for the 202X scenario than for 2019. Table 22 shows that when the heat sales price is as low as 60 €/MWh_{th} there is no payback time, and the IRR is negative.

Table 23. Sensitivity analysis for CAPEX costs for the 2019 scenario.

Storage CAPEX [€/MWh_{th}]	P2H CAPEX [k€/MW_{th}]	Payback time [years]	IRR [%]
445 (Base case)	1 995 (Base case)	9.8	8.6
310 (-30 %)	1 995	7.4 (-24.5 %)	12.2 (+41.9 %)
400 (-10 %)	1 995	9.0 (-8.2 %)	9.6 (+11.6 %)
490 (+10 %)	1 995	10.6 (+8.2 %)	7.7 (-10.5 %)
580 (+30 %)	1 995	12.2 (+24.5 %)	6.1 (-29.1 %)
445	1 795 (-10 %)	9.6 (-2.1 %)	8.8 (+2.3 %)
445	2 195 (+10 %)	9.9 (+1.0 %)	8.3 (-3.5 %)

Table 24. Sensitivity analysis for CAPEX costs for the 202X scenario.

Storage CAPEX [€/MWh_{th}]	P2H CAPEX [k€/MW_{th}]	Payback time [years]	IRR [%]
445 (Base case)	1 995 (Base case)	16.2	3.4
310 (-30 %)	1 995	12.3 (-24.1 %)	6.0 (+76.5 %)
400 (-10 %)	1 995	14.9 (-8.0 %)	4.2 (+23.5 %)
490 (+10 %)	1 995	17.6 (+8.6 %)	2.8 (-17.6 %)
580 (+30 %)	1 995	20.4 (+25.9 %)	1.6 (-52.9 %)
445	1 795 (-10 %)	15.8 (-2.5 %)	3.7 (+8.8 %)
445	2 195 (+10 %)	16.6 (+2.5 %)	3.2 (-5.9 %)

Table 23 and Table 24 demonstrates that the CAPEX of the storage has a greater impact on the payback time and the IRR for both the 2019 and 202X scenarios. The payback time changes between ±26 % for both years and the IRR changes between +42 % to –30 % for the 2019 scenario and between +77 % to –53 % for 202X. When changing the CAPEX for the P2H the payback time only changes between ±2.5 % for both years and the IRR does not change more than +9 % to –6 % for both years.

The power cost in Table 25 and 26 below is the weighted average price for the different sources of electricity (excess power, power from PV park and power from grid).

Table 25. Sensitivity analysis for power costs in the 2019 scenario.

Power cost [€/MWh_e]	Payback time [years]	IRR [%]
18 (-20 %)	9.4 (-4.1 %)	9.0 (+4.7 %)
21 (-10 %)	9.6 (-2.1 %)	8.8 (+2.3 %)
23 (Base case)	9.8	8.6
25 (+10 %)	10.0 (+2.0 %)	8.3 (-3.5 %)
28 (+20 %)	10.2 (+4.1 %)	8.1 (-5.8 %)

Table 26. Sensitivity analysis for power costs in the 202X scenario.

Power cost [€/MWh_e]	Payback time [years]	IRR [%]
41 (-20 %)	14.4 (-11.1 %)	4.5 (+32.4 %)
46 (-10 %)	15.2 (-6.2 %)	4.0 (+17.6 %)
51 (Base case)	16.2	3.4
56 (+10 %)	17.3 (+6.8 %)	2.9 (-14.7 %)
61 (+20 %)	18.6 (+14.8 %)	2.3 (-32.4 %)

When changing the power costs between ±20 %, one can see that it affects the payback time and IRR for the 202X scenario a lot more than what it does for the 2019 scenario (see Table 25 and 26). The payback time changes between ±4.1 % for the 2019 scenario and up to ±15 % for the 202X scenario. The IRR changes no more than ±6 % for the 2019 scenario and up to ±33 % for the 202X scenario.

Summarising the sensitivity analysis, the parameters are listed below from most sensitive to least sensitive:

1. Heat sales price
2. Storage CAPEX
3. Power cost
4. P2H CAPEX

13 Discussion

This section of the report aims to discuss the most important findings.

13.1 Operation Strategy

A crucial step in the real case is to check if the storage is full or if there is room for heat and in that case how much, before sending electricity to the P2H unit. If the storage is full, it is important to know this before converting electricity to heat, to avoid unnecessary startups of the HP or EB and to save on startup costs. It is better to sell the electricity to the grid, even if the spot price is below the PV price limit, than to waste it by converting it to heat without being able to sell or store it. This is not included in this model but is important to add in the future or during a deeper investigation.

Something that affects the system a lot is when electricity from the PV park or power grid can be used. The parameter used for determining this is the spot price limit. Depending on the price limit, different amounts of electricity are sent to the P2H unit. This is also affected by how the spot price for the electricity varies throughout the current year. If the price limit is low and the current year has high spot prices, little electricity will be sent to the P2H unit. If on the other hand the price limit is high and the current year has low spot prices, the amount of electricity that will be sent to the P2H unit will be much higher. Therefore, setting the spot price limit at a good level is crucial for getting the best results out of the system.

13.1.1 Sources of the Electricity

The hours when the PV park produces electricity do not always occur on the hours that have low spot prices. This means that with our model, it can be hard to fulfil the heat demand without adding the option to buy electricity from the grid. As one can see in Table 10 and 11, the heat production cost for when taking electricity only from the PV park in the 2019 case is more expensive than when using only from the grid or both from the PV park and the grid. Meanwhile, Table 10 and 11 show that the amount of MWh_e for when only taking electricity from the PV park is a lot smaller than when taking only from the grid or both from the PV park and the grid. This could be the reason why the CAPEX for the heat production is much higher for the case with only electricity from the PV park (see Figure 21 and Figure 22Figure 22), as the cost is divided by the number of produced MWh_{th}. When the system is only buying electricity from the PV park, the amount of electricity is limited to how much electricity the PV park can produce in one year, while the amount of electricity from the grid is unlimited (as long as it is below the spot price limit). This allows us to get more MWh_e from the grid, and therefore the heat production cost is spread across more MWh_{th}. This means that despite the more expensive purchase price when also buying from the grid, the end price is cheaper because of the larger amount of MWh_e. Of course, this could change depending on how much electricity is available from the PV park as well as the grid.

In Table 10 and 11 one can also see that the compound power price for the electricity is lower for the case with only electricity from the PV park. Since we pay less for the electricity from the PV park than the electricity from the grid, this is expected. On the other hand, in Table 14 it is clear that the compound power price for the case with only electricity from the PV park is higher than the other two cases. This could be due to the spot price limit for the EB in the 202X case being very low, and you then get cheap electricity regardless of the source. In this case we have a lot of excess power (800 MWh_e out of 1 300 MWh_e) and since the price for the excess power is set to 15 €/MWh_e regardless of the spot price, it will not affect the cost for the electricity in a positive way. The spot prices this year are very high and since the spot price limit is low, there are not many hours with low spot price available, so we cannot buy a lot from the grid. Therefore, the compound power price is dominated by the price for excess power.

In Figure 24, one can see that the cost for the storage is much higher for the case with only electricity from the PV park. The reason for this is that the amount of MWh_e for the different cases is almost the same and 96 % of the heat goes to the storage in this case with only electricity from the PV park (compared to 62 % and 75 % for the other two cases, see Table 14), which means that the capacity of the storage will be much bigger. This means that the ratio between the storage capacity and the total heat output is much higher, and therefore the cost for the storage is higher. The reason for such a high share of heat going directly to storage when only using PV electricity is likely because the biggest share of electricity is produced during the summer months, when the heat demand is low or non-existent. When electricity is also bought from the grid, more power is available overall and especially when there is a heat demand. That means that more of the heat produced by grid electricity can be used right after being produced, compared to heat produced by PV electricity.

As is visible in the aforementioned tables, the compound power price is cheaper when using only PV in nearly all cases. This means that using electricity from the PV park makes the business case better than if only grid electricity were to be used, and the more PV electricity the better. One can also see that the PV electricity makes a bigger difference for the total heat production cost for the EB than the HP, especially in the 202X scenario, at least when the P2H capacity is set at 3 MW_e for both technologies as in our trials. It is relatively more important for the EB to have access to more electricity when there is a specific heat demand to fulfil, because it needs more MWh_e than the HP to deliver the same amount of heat. It is also more important other times because of the EB having a low capacity factor at its optimal price limit, meaning that the hours of PV electricity make a bigger difference than for the HP with a high capacity factor.

It should be noted that when we examined the use of different sources of electricity, we used the spot price limits that we had already computed. These price limits were based on the assumption that we would use electricity from both available sources, meaning that the optimal spot price limits in these cases may not be the same as when only using electricity from the PV park or only from the grid. This might have had an impact on our primary results.

13.2 P2H Technology Comparison

If used the same hours and having the same P2H electric capacity, a HP will always have an advantage in heat production compared to an EB, since an EB needs a lot more electricity than a HP to fulfil the same heat demand. In our calculations and results, we have chosen to look at a HP with a COP of 3.5. There are HPs with a higher COP and that would result in a greater advantage for the HP, but of course that could also result in a bigger investment cost. The HP can produce more MWh_{th} compared to the amount of electricity that is driving the process, while the EB can never produce more MWh_{th} than the amount of electricity that is fed in. For a given P2H electric capacity, the more MWh_{th} produced, the cheaper the heat production cost will be. This also means that the capacity of the HP can be a lot smaller than the capacity of the EB to fulfil the same heat demand.

A problem with the EB is that it easily can be over dimensioned, if one wants to fulfil a high heat demand, as is visible in the Filipstad case. As one can see in Figure 18, the higher the spot price limit, the higher the heat production cost for the EB and eventually the production cost for a HP will be cheaper than the production cost for an EB. Therefore, it does not seem possible to have an EB with a high capacity factor while it also has a lower heat production cost compared to the HP. At high capacity factors, the weight of the power costs become more important in the cost breakdown, which means the most power-efficient technology is rewarded. The big advantage of an EB seems to be a small capacity factor, meaning that it only runs a small portion of the year.

In Table 17 and Table 18, case 1, one can see that the capacity for a HP varies between (0.3-0.55) MW_e, while the capacity for an EB varies between (2-35) MW_e. The variations between the capacities for the EB is a lot bigger than for the HP and that makes HP a better choice in the long term, based on our model. In Table 18, one can see that the size of the EB for the 202X-1 and 202X scenarios reaches its maximum of 35 MW_e because it is limited by the grid and PV park capacity. This means that the heat demand for these years will not be reached with an EB, making the HP a better choice. Also, since the spot prices vary and are hard to predict and affect the capacity of the P2H unit each year, it could be beneficial to choose the P2H unit that is even in capacity over the years. As mentioned, the optimal capacity of the HP is much more even over the years than the capacity of the EB in the Filipstad case, which is another reason to choose the HP. This is due to the fact that the optimal sizing of the HP depends less on the chosen reference model of spot price distribution, since the power costs represent a lower weight in the total costs than for the EB.

As can be seen in Table 18, for the 202X-1 and 202X scenarios, the EB cannot fulfil the heat demand. Since the capacity of the PV park is 20 MW_e in this case, the maximum amount of electricity that the EB can receive from the PV park in one hour is 20 MWh_e. Because of the grid capacity being limited at 15 MW_e, the EB cannot receive more than 15 MWh_e in one hour. That is why it is unnecessary for the EB to have a capacity higher than 35 MW_e. To be able to fulfil the heat demand with an EB these years, the spot price limit needs to be raised, but as can be seen in Figure 30 and Figure 31 in Appendix A, the higher the spot price limit the higher the heat production cost for the EB. As can be seen in Table 17 and Table 18, the heat production cost for the HP is already lower than for the EB, making the HP a better choice once again.

The heat production cost for the HP is cheaper than for the EB in every year, as can be seen in Figure 27, which is another reason to choose the HP. As can be seen in the figure, the heat production price for the 202X-1 case for both technologies are a lot higher than for the other years. This shows that the results depend on the year in question’s spot prices. That is a reason for examining the results for several years’ spot prices, to see what the outcome is in different future scenarios.

A disadvantage for the HP is that it cannot make use of all the excess power from the PV park. The capacity of the HP is less than 1 MW_e for every case in the results and the excess power from the PV park is 5 MW_e, which means that more than 4 MW_e is wasted. The EB on the other hand can take care of the excess power in almost every case, since the capacity is greater than 5 MW_e for every case except for case 1 in 2017 and case 3 when the addressable heat demand is set to 30 % (see Table 18 and Table 20). Also, during the times when the spot price is lower than the spot price limit and the PV park does not sell electricity to the grid, the situation is similar. Then the HP can only utilise less than 1 MW_e and about 19 MW_e is sold to the grid despite the low profits, while the EB could utilise all of the available PV electricity in some cases. This means that depending on what you want from the system, the EB could still be a better choice. This is definitely the case for Filipstad if the goal is to use as much of the PV power as possible when the spot prices are low or there are grid limitations.

13.2.1 Comparison of Heat Pumps

As mentioned in section 5, there are a number of different HP technologies that could be used in a system like this. The choice of going for an excess heat-source HP was made due to it being cheaper than the air-source option, but this was based on a single source and so the prices could vary. It does have an advantage in being able to utilise excess heat from industries and can therefore reduce energy consumption, making it useful in several ways. In this thesis we have assumed that there will always be excess heat available to power the HP, but that may not be the case in reality. It is possible that the air-source option would be better in the real case, since air is an abundant resource. However, the temperature of the outside air affects the efficiency of the HP and so they may not be the best option in the wintertime in Sweden. Ground-source HPs, on the other hand, are energy-efficient since they can utilise the heat in the ground and are not affected by the outside temperature in the same way. They are also an option for this kind of system, depending on the price. Industrial wastewater is another option as source as it is a good choice for integrating with DH due to its higher temperature.

The choice of HP is this thesis is not a definitive answer for which type of HP is the best option, but rather a suggestion. It depends on which circumstances apply, such as if there is excess heat or wastewater from industries, if the ground is suitable for ground-source HPs and temperature conditions in the outside air. Also, investment cost is of course a major factor.

13.3 Sensitivity Analysis

Our system is very complex and there are many parameters that can be varied and most of them depend on each other. We have chosen to vary three parameters in our sensitivity analysis: which year's spot prices we are looking at, the capacity of the PV park and the addressable heat demand. This was done to get a better understanding of how much the capacity of the P2H unit and the heat production cost varies in the different cases.

In case 1, see Table 17 and Table 18, it was clear that the heat production cost for the HP was cheaper each year, and the capacity of the HP was a lot more even than the EB. This shows that the HP is a better alternative over a longer time so that the capacity does not get incorrectly dimensioned. In case 2, see Table 19, the heat production cost as well as the capacity for the HP are also more even than for the EB. In the 2019 scenario the heat production cost for the HP varies less than ±1 %, while it varies between ±3 % for the EB. For the 202X scenario there is an even bigger difference, as the heat production cost for the HP changes less than ±2 % and the EB has changes down to –22 %.

In case 3, see Table 22, one can see that the differences are fairly even overall. The changes in the heat production cost and the P2H capacity for the 2019 scenario is pretty much the same for both the HP and the EB. In the 202X scenario, the EB exceeds the maximum capacity of 35 MW, and it is therefore unfair to compare EB and HP with each other. On the other hand, one can see in the table that the heat production price for the EB will be clearly cheaper for the case with 30 % addressable heat demand, a change of –24 %, which could have been even bigger if the EB did not have a maximum capacity of 35 MW_e.

When comparing case 2 and case 3 with each other, one can see that changing the heat floor demand (case 3) affects the heat production cost more than changing the capacity of the PV park (case 2). On the other hand, the changes in the capacity of the P2H is a lot less for case 2 than for case 3. In general, it seems that the price differences will be largest for the 202X scenario, especially for EB. The reason for this could be the higher and volatile spot prices.

The sensitivity analysis shows that the HP is a better alternative regardless of the year looked at, the variations of the size of the PV park and the addressable heat demand in the case of our chosen city.

13.4 Heat Production Price

An important part of the heat production price is of course how much it costs to produce the heat. Looking at Figure 13, one can see that the production cost for heat produced by STE can be as low as 40 €/MWh. If the cost is assumed to not include storage, that is a level of cost that this kind of system can hope to compete with. Looking at Figure 24, for instance, the cost breakdown shows that for an EB in a year like 202X the heat production cost without storage is below 40 €/MWh. The same can be said for the other cost stacks when the P2H capacity is kept constant at 3 MW_e, showing that it is possible for both a HP and EB in different spot price scenarios to have a relatively low heat production cost when disregarding storage.

The type of fuels used in a DH system will affect the heat production price, which is the price our product is competing with. Therefore, our chances of selling the produced heat depend on the local circumstances. If the local DH company has access to very cheap fuel or has low production costs for other reasons, such as DH systems with many facilities, the possibility of entering that market is low. On the other hand, if the DH company has very high production costs during the winter as described in section 7, our product could be of interest to them as a replacement for their peak load fuel. The higher the cost of the peak load fuel, the higher margins we can add to our heat sales price.

As mentioned in section 7, DH fuel prices could rise in the coming years. This means that the DH companies' costs may rise as well, which offers an opportunity for our kind of system. Therefore, even if our system does not seem like a great investment for a 202X scenario, this could change with rising fuel costs. Furthermore, since the heat production cost varies a lot between the 2019 and 202X cases, it means that the spot prices affect the cost a lot. Since the spot prices are affected by a number of reasons as described in section 4 it is very uncertain how they will look in the future. Even if only one of the listed reasons' conditions changes in the coming years, the spot prices could be affected both negatively and positively. As such, it is not certain that the results we have collected for the 202X scenario will be representative in the future. As a consequence of this, the heat production price which we think is acceptable today may change in the future.

Assuming the local DH company in the case of Filipstad have very high production costs in the wintertime, we have seen that the system incorporating a HP is competitive. The EB, on the other hand, is not so competitive. Because of this we chose to make a P&L statement with the HP as a case to further examine the profitability.

13.5 P&L Statement

First of all, when comparing the base case of a heat sales price of 80 €/MWh_{th} for the 2019 and 202X scenarios, it is clear that 2019 represents a far more profitable case. A payback time of 9.8 years and an IRR of 8.6 % is an acceptable result, while the corresponding values in the 202X case of 16.2 years and 3.4 % are not. Therefore, the choice of a sales price of 80 €/MWh_{th} could be acceptable if the spot prices in the future correspond to the historic data of 2019. However, if the spot prices are more like the predictions for 202X, 80 €/MWh_{th} would not be a good enough price to cover the costs of the investment. However, as previously mentioned, the DH fuel prices could rise in the future, making the heat production cost for the DH companies more expensive. That means that it could be possible to use a higher sales price for our heat in 202X.

There are some limitations in our use of this P&L analysis. Some figures used, such as equipment and project development costs and the like, are only approximations based on experience. The tax calculations could also be done more in depth. We have however deemed that this approach is enough to get a rough look at what level the key parameters are at and what they need to be set at to find a profitable case.

13.5.1 Sensitivity Analysis

When comparing different heat sales prices for the 2019 and 202X scenarios, the 202X scenario proved to be more sensitive to the changes, especially the IRR. The results also show that in the case of 2019, 80 €/MWh_{th} is the lowest price which is acceptable for good values on the payback time and IRR. For the 202X case, the heat sales price must be at least 110 €/MWh_{th} for the HP. As stated earlier in this discussion, that is a quite high price and is perhaps not feasible unless the DH fuel prices rise substantially, or local conditions allow a price like that. In other words, if the spot prices evolve as is predicted in 202X, the HP may not be a good investment to make.

The 202X scenario proved to be the most sensitive to changes in CAPEX costs as well, especially the IRR once again. Also, none of the changes made resulted in an alternative with acceptable payback time or IRR. For the 2019 scenario, on the other hand, the change in P2H CAPEX does not impact the profitability much and is still considered to be a good investment, when looking at payback time and IRR. The increase in storage CAPEX, however, proves that the business case is right on the edge of being considered a good investment in terms of payback time and IRR. For both the 2019 and 202X scenario, the change in storage CAPEX had a much larger impact than the change in P2H CAPEX. In fact, the results of the P2H CAPEX change did not differ much between the two years regarding payback time.

When analysing the impact of a change in the power cost, the 202X scenario is once again more sensitive, but is still not considered a good investment based on payback time and IRR. The sensitivity could in part be because the base case is a higher power cost for the 202X scenario than 2019, since 202X had higher spot prices in general, which is reflected here. It also means that a 10 % change for the base power cost in the 202X scenario results in a bigger change in €/MWh_e, so it is no surprise that the change in payback time and IRR should also be higher. Still, the 2019 cases are on the verge of being a good investment in terms of payback time, but the IRR remains at a good level for each case.

13.6 Limitations of the Model

As previously mentioned in the discussion, the spot price limits each year affect the results a lot. Therefore, it is important that they are reasonable and trustworthy. An uncertainty regarding the spot price limit includes how it is calculated for each year. We have not included the storage cost in these calculations, which may have affected the results, since the storage size is affected by the capacity of the P2H unit. The spot price limits we have used are essentially the same regardless of the P2H capacity, which may not be entirely realistic, because of the storage cost. Since the storage capacity is affected by the amount of electricity the P2H unit has used, everything is connected. Therefore, there may be a better way of deciding the spot price limit.

Furthermore, when we examined which sources of electricity are the best to use, we based the investigation on the spot price limits used for all other cases. The spot price limits were calculated with the assumption of us using electricity from both the PV park and the grid, and as such the results may vary if the price limit was instead based on only using one source. The best way may have been to calculate three different spot price limits for the three different cases of electricity source used.

As previously mentioned, there are limitations with the storage and how it is dimensioned in this model. A disadvantage with this dimensioning strategy is that it is based on specific data from one year, in terms of solar irradiation and spot prices. Of course, this brings uncertainty to the sizing of the storage and the validity it has. Another way to do it could be to instead use the average spot prices of a couple of years, but the question then is which years are representative for the future. One could also use average prices of forecasts for a few years, but these are uncertain and could change. Since none of these methods are fool proof, we made the decision to look at one historic case and one future case.

Another limitation is the price which we assume we pay for the electricity from each source. When we take electricity from the PV park, we assume that it is 15 % cheaper than electricity from the grid. We also assume that excess electricity, which would have been wasted if not used by the P2H unit, always costs 15 €/MWh_e. Both these prices are only guesses and probably have different impacts on the results depending on the case.

13.6.1 Source of Errors

Regarding the choice of HP technology, we chose the excess heat-source HP as it was cheaper and assumed that we would have access to excess heat whenever needed in our model. This could be a drawback in reality, where excess heat is not always available. Air, however, is abundant and would always be available in reality as well. Therefore, it may be more realistic to use an air-source HP instead.

Regarding the economics of the HP and EB, the HP numbers were based on a P2H capacity of 10 MWh_{th} and the EB numbers were based on up to 5 MWh_{th}. As our results later showed, these capacities were not realistic for our cases. For the EB, it is probable that the price per MWh_{th} would be lower than the used number since every capacity we found in our results was larger than 5 MW_e, and that could affect the profitability. For the HP, the price per MWh_{th} could instead be higher, which would also affect profitability.

We chose a storage efficiency of 85 % for the pit heat storage, which is on the high end of the spectrum according to our source. Therefore, it is possible that that value may not be easily attainable in reality. If the real efficiency is usually lower than 85 %, that would have a negative impact on the profitability.

13.6.2 Spot Price Limit

Since the cost of the electricity from the solar park is assumed to be less than if the electricity would be bought from the grid, the spot price limit for electricity from the grid cannot be higher than the spot price limit for the PV park electricity. This is the reason we chose to use the same spot price limit regardless of which source of electricity we use. Otherwise, if the spot price is between the PV spot price limit and the grid spot price limit, the electricity that has been sold from the solar park to the grid can be bought back to the P2H unit. Full price would then be paid for the electricity from the grid, instead of a lower price from the solar park. For this reason, the PV spot price limit and the grid spot price limit are the same.

Since the spot price varies so much between years and can be affected by many different factors, the spot price limits each year need to be updated in order to get the right amount of electricity. This is important if our model would be applied to reality. If not, the amount of electricity going to the P2H unit would vary a lot, and the unit would be over- or under dimensioned. The same goes for the storage. One year the amount of electricity would be a lot more than what would fit in the storage, and another year it would be so little electricity that the heat demand would not be close to being fulfilled.

Something we can see from the results is that the HP is most competitive at a higher spot price limit than the one at which EB is the most competitive. This could affect the profitability of the PV park, which we have not looked at more closely in this report. It is reasonable to believe that a lower price limit is better for the PV park, since it will have more chances to sell the electricity at the higher spot prices. For example, for the 202X scenario, the optimal spot price limit for a HP is 110 €/MWh_e, which is very high. On the other hand, the spot prices were overall very high this year and since the capacity for the HP is low, the amount of electricity used by the HP each hour is not that big. This means that the PV park still has a lot of electricity available to sell, even if a small portion is reserved for the HP.

13.6.3 Seasonal Storage

The cost for the seasonal storage is a big part of the total heat production cost for both the HP and EB. Therefore, it would be beneficial for the business case if it were possible to lower that cost somehow. Unfortunately, the chosen investment cost for the pit heat storage is already in the lower range of investment costs identified in the study “Teknoekonomisk jämförelse av olika tekniker för termiska lager i fjärrvärmenät” by Energiforsk. However, one can hope that the maturity of the storage technology will bring down the investment cost or that there are new technologies with lower investment costs. Another possible solution is if one could find an already existing storage solution which is close to a DH network, with space for a PV park. Then it might be possible to acquire or rent that unit, instead of having to take on the whole investment cost of building a storage.

A challenge with pit heat storage is that it requires a lot of space, which can be a problem in a built environment. It is therefore important to find a good placement for the storage - one that is not too far from either the PV park or the DH connection point. This is something that needs to be closely looked at before going further with the business case. However, the pit heat storage technique does not require as much of the environment as, for instance, rock beds do.

In the future one of the immature technologies such as latent heats storage or thermochemical heat storage could be an alternative to the pit heat storage, since these have a better operating temperature and a better efficiency. Today the investment costs are way too high, and the technologies need to be developed more in order to compete against the more mature technologies.

In our Excel model, we chose to not limit the size of the storage. When looking at the results from the Filipstad case, one can see that the HP had an energy storage capacity of roughly 6 000 MWh_{th} in both the 2019 and 202X cases, corresponding to the size of the storage we based the CAPEX cost on. The EB, however, had a capacity of nearly 9 000 MWh_{th} in the 2019 case, which is quite a lot more than the reference storage. Either way, the storage sizes we obtained in the Filipstad cases seem to be reasonable.

13.6.4 Heat Demand

Something that needs to be considered in this system is that there must be a DH customer that buys the produced heat, or the business case does not exist. Before dimensioning the system, one should make sure that there is a demand for the produced heat. Furthermore, one must take into account that there may not be a demand for heat at the current moment, despite electricity being available for the P2H technology. The system depends on what the heat demand looks like in every moment. In the ideal case, there would be exact forecasts for both heat demand, spot prices and PV electricity production to determine precisely how to size the system, but this is not realistic. Therefore, we have relied on simpler forecasts and patterns in this report.

The heat demand will vary depending on which DH system is considered. It depends on how many customers the DH company has, how high consumption they have, weather conditions and what time of year and day, to mention a few factors. Therefore, it is not possible to predict exactly how high the demand will be at a given time, but heat load graphs may be consulted to identify general patterns, as we have done. This way it is possible to determine when peak loads are to be expected, and as a result when expensive fuels are expected to be used. This provides us with an opportunity to replace the expensive fuels.

In this report, we have chosen to define the heat demand we can match in the base case as 40 % of the total heat demand of the current city, and only during the colder months. This number depends on the DH system, and which fuels they use, as well as what price is acceptable for the DH company to buy heat from our system. It is therefore possible that the addressable heat demand could be both higher and lower than in the case of our chosen city, and in some cases, it could be too low to be worth considering as a business venture.

13.7 System Overview

A major part of the system is the PV park production. How much electricity a PV park produces depends on both technological and geographical factors, which means a certain installation may not yield the same production profile at another location. However, as mentioned in section 3, the solar irradiation in the southern parts of Sweden does not differ much. Therefore, even though the production park profile used in this system is based on a theoretical solar park in a chosen city, the production profile should still be roughly the same in other parts of southern Sweden. When examining other cases, one is able to simply scale the rated power of the solar park up or down to obtain realistic results.

There are however more things to consider if other cases than the chosen city are to be examined. Every city has different conditions, for instance regarding geography and size of the population. Moreover, the DH systems will also differ. The systems may be bigger or smaller, have more or fewer facilities, use different fuel mixes and have a different number of customers. However, the heat demand profile should remain roughly the same, even if the magnitude of the demand is different. The decision of how much of the heat demand should be covered by the P2H-produced heat should also remain the same for the same reason. Hence, when looking at different cases, the heat demand simply needs to be scaled up or down from the base case.

13.7.1 Limitations of the System

There are a lot of limitations for this kind of system. One clear limitation is that the solar park only produces electricity when the sun is shining, and it was therefore necessary to add the possibility of purchasing electricity from the grid. If, for example, the solar irradiation is low one year, the heat demand could still be satisfied to some extent for this reason. The addition of electricity bought from the grid offers some security in the heat production, which could be beneficial if a contract for delivering a certain amount of heat has been signed.

When dimensioning the solar park, one needs to stay realistic in order not to examine too large parks if it is stationed close to a city. The size we chose of 20 MW_e is however assumed to be a reasonable size, because of the size of the already existing parks in Sweden. The size could be interesting to consider when determining which city's DH market you wish to enter, as the heat demand of Filipstad is only 4 % of Helsingborg's heat demand. That means that the size could be a limiting factor depending on how big the local heat demand is, since a PV park with a capacity of 20 MW_e may not be able to satisfy 40 % of the heat demand in Helsingborg.

Also, one must remember that at the end of the day, what determines if the case could be profitable or not is if there is a possibility to sell the produced heat. Even if the heat production cost ends up very low, it does not matter if there is no customer. Perhaps the system needs to be tweaked to produce less heat if the actual heat demand is lower than what we assume for our chosen city, or perhaps the local DH company is not interested at all. It all depends on the local circumstances of the city and the DH companies.

The DH system also offers limitations depending on the temperature levels required. This must be considered when choosing a storage method, as some storages are not able to cope with temperatures over 80 ℃, which is the most common temperature in DH networks today. However, with low temperature DH networks being developed, it could change the situation. Then other storage methods may be possible to use instead of pit heat storage, if they were cheaper or easier to maintain or install.

The capacity of the P2H unit is also a limitation for the system: It limits the amount of electricity that can be converted to heat each hour. This could be an issue if the amount of electricity which exceeds the grid capacity a specific hour is larger than the P2H capacity, as that results in curtailed electricity. This means that in systems where the grid capacity is limited, for instance in cases with smaller cities like our chosen city, one must be mindful when dimensioning the P2H unit. If the overarching goal is to utilise every ounce of electricity, even if that results in less profit, it may be better to go for a unit with higher P2H capacity as that would minimise the curtailed electricity.

If the spot price limit is low and the current year has high spot prices, the amount of electricity sent to the P2H unit will be low. If, on the other hand, the spot prices are low, there will be a large amount of electricity available. The two years we have chosen to look at in this study, 2019 and 202X, differ quite dramatically regarding the spot prices. The prices in 2019 were quite low and even, while the 202X prices were generally higher and varied much more. That means that the amount of electricity from the PV park and the bought electricity from the grid will differ each year if the price limits are set at the same level. In turn that will affect what P2H capacity is needed to satisfy the heat demand and how big the storage needs to be.

13.8 Environmental Impact

When the same amount of electricity is available for a HP and EB, and the power of them is the same, the HP will always produce more heat. The EB will always lose some energy in the conversion since its efficiency cannot, even theoretically, exceed 100 %. Meanwhile, the HP will always produce more heat than the amount of energy which entered the machine due to the nature of the technology. This means that the HP will always be a better choice when only considering amount of produced heat for the same amount of input electricity. For the environment, that is a clear advantage. If this sort of system can replace some of the expensive and sometimes not so environmentally friendly peak load fuels in DH systems, that would mean a decrease in the environmental impact of the system. Out of the two P2H technologies, the HP provides the biggest impact when only considering energy efficiency.

The advantage of an EB, however, is that its bigger P2H capacity means it can recover more of the excess power from the PV park in a system like ours. While the capacity of the HP is dimensioned at less than 1 MW_e in the Filipstad cases, the EB has a much larger capacity in all cases. That means that if the goal is to recover more electricity which would otherwise have been lost, the EB is a better choice from an environmental point of view. Furthermore, when considering a system like this, the technology which provides the biggest incentive for building a PV park is the one which makes a bigger environmental impact in a larger point of view.

14 Conclusions

When choosing between a HP and an EB, one must know what factors are prioritised. If the goal is to utilise a lot of the excess electricity from a PV park, the EB is probably the best choice, because it has a lower investment cost. If the goal is instead to reach a low heat production cost, the HP is probably better, as it makes the investment cost per produced MWh heat lower due to its high COP. However, the results will always depend on the local conditions of the capacity of the PV park, if we wish to satisfy a heat demand or only make sure electricity is not curtailed. All in all, one could say that if a high capacity factor is desired, the HP is the ideal choice while the EB is superior at a low capacity factor.

All things considered, the biggest sensitivity in the P&L statement is found when changing the heat sales price and storage CAPEX for both years, but the power costs also affect the results a lot for 202X. The fact that the storage CAPEX is a sensitive parameter is not a surprise, as the cost stacks shown in the results section indicated it being a large share of the heat production cost. Finding other ways to store the produced heat could be crucial if this system is to be profitable. For the same reason, it is also no surprise that the power costs are a sensitive parameter for the 202X scenario, since the power costs are nearly doubled in the case of our chosen city for the HP between the 2019 and 202X scenarios. The heat sales price being a sensitive parameter means that the business case is dependent on how the DH fuel prices evolve the following years, as well as what other sources for heat the DH companies use and the price of these.

Looking at the two main scenarios, with spot prices from 2019 and 202X, it is clear that the spot prices play a major role in the profitability of this kind of system. While a system with a HP stands a good chance of being profitable in Filipstad in a year like 2019 as per our P&L statement, it does not look as good in a year like 202X. While a heat sales price of 80 €/MWh_{th} is sufficient in the 2019 scenario, at least 110 €/MWh_{th} is required in the 202X scenario. Again, profitability in the 202X case depends on future DH fuel prices.

Considering that the future is expected to have more volatile spot prices as seen in 202X, the EB is likely the more interesting choice. This is because it can utilise the hours with low spot prices in a better way as its lowest heat production cost is reached at a low capacity factor, meaning it is the cheapest when only being used few hours of the year. The EB also seems to benefit more from a PV park, again because of the small amount of running hours during a year, making the added, cheaper, PV electricity have a bigger impact on the heat production price.

Other important limitations of the system are the PV park capacity, spot price limit, capacity of the P2H unit, if there is a customer for the produced heat and temperature levels of the produced heat. The PV park capacity limits the amount of electricity available in the system along with the spot price limit and the P2H capacity. There must also be a customer for the produced heat, and to even be able to sell the heat to the DH companies the temperature levels of the heated water must be adequate. These topics require further investigation to be able to confirm the suitability of the system.

15 Future Work

In this report, we have mainly focused on satisfying a certain heat demand and optimising the system from this point of view. As previously mentioned, there could be other cases which we have not examined where the EB is the more obvious choice for best suited P2H technology. This could for instance be when the goal is to utilise the most excess electricity from the PV park, or when the heat demand is very low to mention a few possible cases. It would be interesting to see whether the addition of adding the option of selling flexibility services to the grid would impact the case.

It would also be necessary to consider this system more from the PV park's point of view, and what it stands to gain from it. It would be interesting to see how much the system impacts the case of building a PV park, and how much additional revenue can be expected. The spot price limit could also be studied to see where the line for a reasonable profit for the PV park would be drawn, as well as to see whether there is a better way to set the price limit than the method we used.

In the future it would be interesting to look at possibilities to combine the system with other technologies, such as district cooling, wind power and photovoltaic-thermal solar collectors (PV-Ts). For district cooling, only the HP technology is interesting as it can both heat and cool. Also, since our system at the moment only produces heat, which is mainly used in the winter, district cooling could expand the market further if cooling is in demand in the summertime. Furthermore, as mentioned in section 5, air-source HPs are especially effective if used for both heating and cooling and could be a good option of P2H technology in this case. It would however be necessary to look at other storage solutions if cooling is added to the system, as other storage technologies could suit cooling better. Wind power could be interesting to add to the system as well, because its electricity production is not limited by the fewer hours of sun in the winter months. PV-Ts are interesting because they use sunlight to produce both electricity and heat.

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Appendix
Appendix A

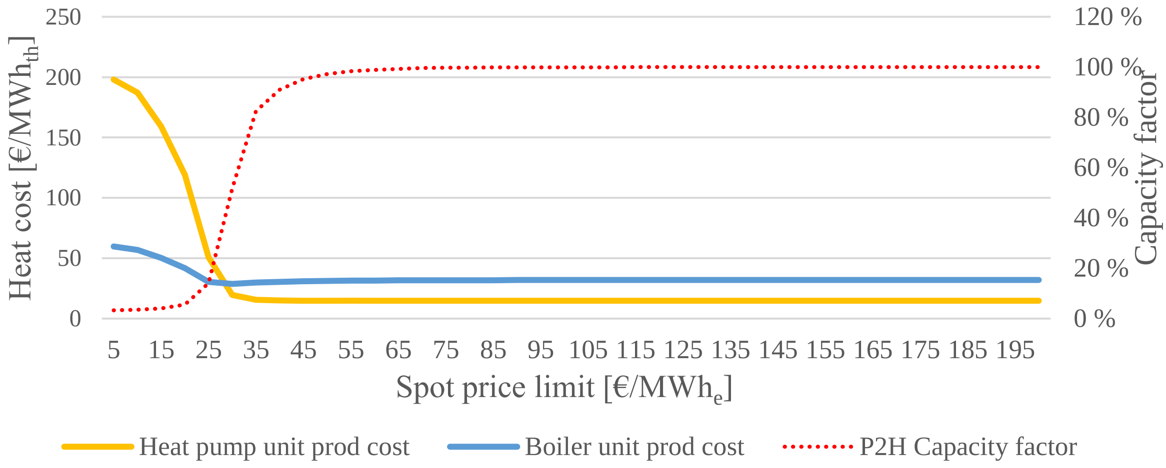

Figure 28. Heat production cost and capacity factor for HP and EB compared to the spot price limit for 2017.

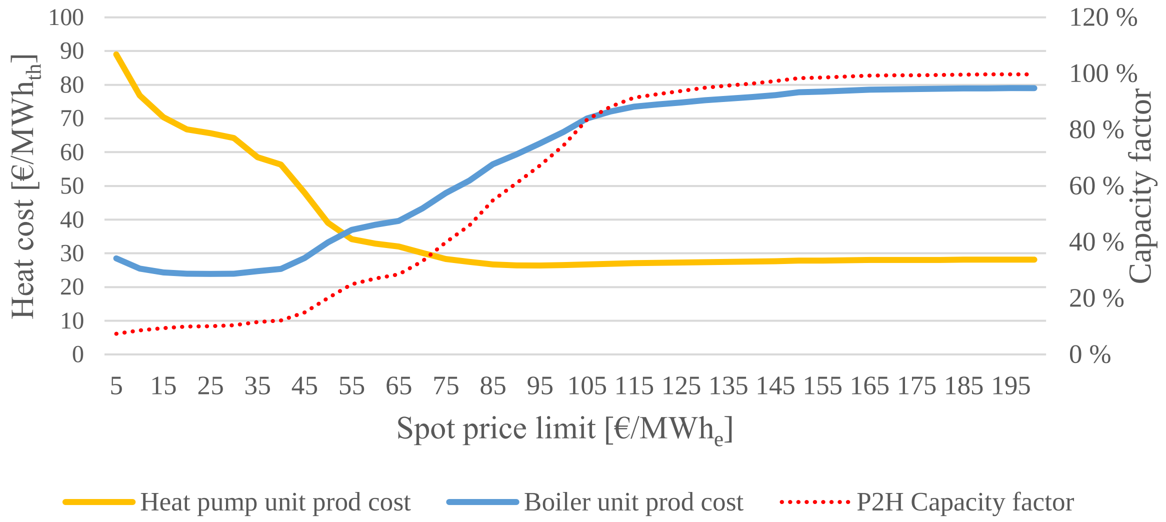

Figure 29. Heat production cost and capacity factor for HP and EB compared to the spot price limit for 2018.

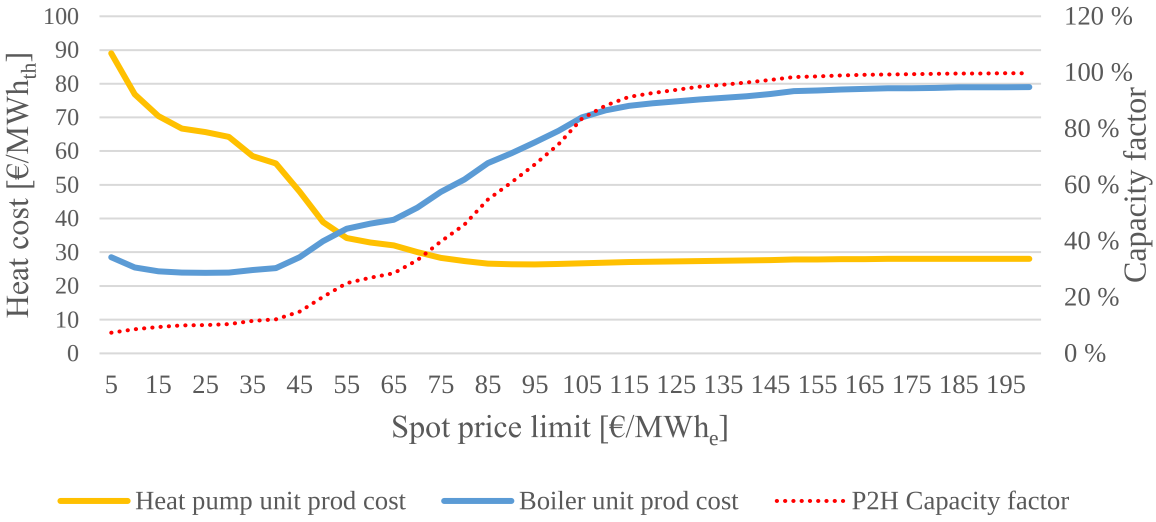

Figure 30. Heat production cost and capacity factor for HP and EB compared to the spot price limit for 202X – 1.

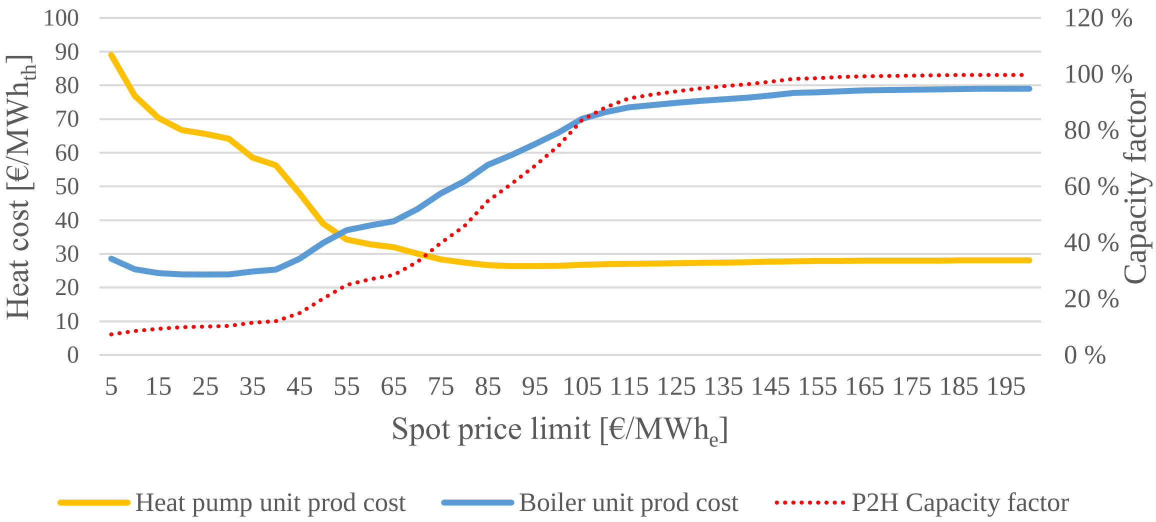

Figure 31. Heat production cost and capacity factor for HP and EB compared to the spot price limit for 202X + 1.

Appendix B

Table 27. Annual earnings for the PV park from selling electricity to the P2H unit. Data for price distribution similar to 2019.

	HP	EB
Excess electricity [€]	1 556	14 867

Electricity below spot price limit [€]	32 356	33 537
Total [€]	33 913	48 404

Table 28. Annual earnings for the PV park from selling electricity to the P2H unit. Data for price distribution similar to 202X.

	HP	EB
Excess electricity [€]	2 312	14 867
Electricity below spot price limit [€]	74 531	16 615
Total [€]	76 843	31 482