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Price model analysis for district heating systems

How should district heating companies charge their customers?

Master's thesis in the Master's Program Sustainable Energy Systems

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DEPARTMENT OF ARCHITECTURE & CIVIL ENGINEERING
CHALMERS UNIVERSITY OF TECHNOLOGY
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Master's thesis ACEX30

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Cover: Price model analysis and evaluation of district heating systems using Utilifeed's pricing tool as well as cost calculations of heat pumps using Python to evaluate the competitiveness of heat pumps against district heating.

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Abstract

A district heating (DH) price model is referred to as the way DH companies charge their customers for supplied heat. In Sweden, the price models of DH have been moving towards being cost-based rather than market-based as it reduces the economic risks for DH companies. However, a challenge for the DH companies is to know what works when setting up a price model as different customers want different things. In general, the customers want a price model that is understandable, predictable and simple. Therefore, analysis and evaluation of different price models in three different DH networks are performed to see how the components of the price models behave and perform between years and networks.

A heat pump (HP) can be used as an alternative for DH. HPs are the biggest competitor of DH in Sweden today, which is why the competitiveness of HPs against DH is analyzed. The reasons why choosing HP over DH is problematic are firstly, that the DH companies lose customers. Secondly, if the electricity mix in the network is not 100% renewable, the HP might be increasing the demand for non-renewables as it runs on electricity and would increase the peaks in the system which are typically covered with non-renewables.

The results indicated how different networks benefit differently from including different cost components in the price model, depending on the system's behaviour. Inefficient systems with high return temperatures (RTs) would, for example, benefit from charging for too high RTs with the use of a RT component as part of the price model. To avoid significant fluctuations in the fixed costs of the revenues, using a power signature for the power cost component, where the capacity is sized based on a cold day, results on average in 2.5-3% less fluctuations compared to the other price models. The fixed costs will vary more if the cost is based on previous, measured usage, making the revenues less predictable. Using power signature also showed the best performance during warm year, the year when the companies are at the most significant risk of getting lower revenues than expected as the heat demand decreases.

The HP results showed that it depended on the HP size if the investment was profitable or not, as a larger size will substantially increase the investment cost. All the small residential buildings included showed prominent results while all the industrial buildings were not profitable. However, the assumed interest rate and the lifetime of the HPs and electricity prices have a significant impact on the results, which is essential to keep in mind.

Keywords: District heating, price models, revenues, KPI, heat pumps.

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Aníta Hlín Gudnadóttir, Gothenburg, June 2022

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

COP	Coefficient of performance
DH	District Heating
GHG	Greenhouse Gas
HP	Heat Pump
HX	Heat Exchanger
KPI	Key Performance Indicator
PM1	Price model 1
PM2	Price model 2
PM3	Price model 3
PM4	Price model 4
PM5	Price model 5
RT	Return Temperature
SEA	Swedish Energy Agency
SMHI	Sveriges meteorologiska och hydrologiska institut

Nomenclature

Below is the nomenclature of indices and parameters, and that have been used throughout this thesis.

Indices

i,j	Indices for heat load at hour j in month i
i	Index for month of the year

Parameters

$El.\ price_i$	Monthly electricity prices
$Spot\ price_i$	Monthly NordPool spot prices
$Heat\ load_{i,j}$	Heat load of building
COP_i	Coefficient of performance
Cap_{HP}	Heat pump capacity

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1
Introduction

Article 2a in the Paris Agreement states that the parties to the agreement should make sure that the increase in global average temperature is kept well below 2°C and pursue to keep it below 1.5°C [1]. In order to reverse climate change, the use of renewable energy sources needs to be increased in the absence of fossil fuels which emit greenhouse gases (GHG) into the atmosphere, thereby contributing to climate change. According to the IEA [2], the Net Zero Emission by 2050 scenario mentions district heating (DH) as an essential part of the solution to decarbonise the heating sector since the DH sector allows for integration of clean and flexible energy, which does not rely on fossil fuels.

DH is a system which delivers heat from thermal energy plants to buildings through an underground pipe network for heating purposes. Usually, there is a central heat generation plant, like combined heat and power plant (CHP) which generates the heat and delivers it into the pipe network [3]. Frederiksen and Werner [4] define district heating as "to use local fuel or heat resources that would otherwise be wasted, in order to satisfy local customer demands for heating, by using a heat distribution network of pipes as a local market place". Half of Europe's final energy consumption comes from heating, and cooling [5] and according to Persson and Werner [6], district heating provides only about 12% of that heat. However, studies have shown that DH has the potential to grow in the EU [7] and thereby contribute to the mitigation of climate change with decarbonisation.

In Sweden, DH is a well-established industry that meets approximately half of the country's heat demand [8]. Although it is an established industry, DH is still facing significant challenges in Sweden. One particular challenge area is how DH companies charge their customers for supplied heat, i.e. their price models. For the DH company, it can be hard to know what will work and what will not when deciding how the price models should be set up. Different customers want different things but in general, they want a price model that is understandable, predictable and simple [9]. Sernhed et al. [9] mentions that transparency and understandability is essential which is also what the DH industry wants. According to Rydén et al. [10], DH companies need to review their costs and become more efficient since, in a mature/shrinking market, it is necessary to maintain competitiveness. Previously, volume increase has been the "recipe", but that time is over.

Heat pumps (HPs) are currently the most significant competitor against DH, while before, it was mainly electric and oil heating [8]. Since the market share of HPs has been increasing, it is crucial to have a good price model that the customer understands and thereby minimize the risk of the customer to decide to switch to a HP. Even though HPs are, in general, an efficient way of heating, it highly depends on the country's electricity mix if it can be considered renewable or not [11]. Therefore, in a country where the share of renewables is low, HPs would only increase the electricity demand, hence, not contributing to less GHG emissions. On the other hand, if the electricity mix has a high share of renewables, it is an excellent way of contributing to decarbonisation [11, 12].

1.1 Aim

The thesis aims to analyse and evaluate the performance of DH price models in three different DH networks. It can be hard for the DH companies to know what will work and what will not when setting up a price model as well as it can be hard for them to predict the upcoming revenues. In Sweden today, there is no regulated way of how the price of DH is set, which means that each DH company is doing it their own way. The price model should be transparent so the customer understands what is being paid for, and the price needs to be fair. However, the DH companies also need revenues to survive, so it is crucial to build a well functioning price model that works even though outside conditions like the weather changes from year to year. The thesis will therefore look at how different price models perform between years as well as looking at how different weather scenarios affect the revenues.

As mentioned in the introduction, HPs are the biggest competitor of DH in Sweden today. Hence, another part of the thesis will be to look at how HPs compete against DH. The comparison will be done by calculating and comparing what 15 different buildings (five buildings per network) would pay for DH versus what they would pay for installing and operating a HP instead.

1.2 Scope and limitations

Since the included prices for the DH cost components in the calculations will be assumed based on average DH prices in Sweden, the main focus of the thesis will be to look at how the revenues change between years, rather than focusing on the exact value of the revenues. The same assumed prices will be used for all three networks to see how the price models react to different heat loads and weather conditions even though, in reality, these networks would not have the same prices due to different production costs.

The HP calculation will be limited to the coefficient of performance (COP), and HP capacity of a ground source heat pump (GSHP), of the type NIBE F1345, a HP recommended for larger buildings as well as they are limited to electricity prices of 2019.

2

Background

2.1 District heating systems in Sweden

The district heating sector in Sweden stands for around 49 TWh of the total energy consumption, 369 TWh, according to data from the Swedish Energy Agency (SEA), when including both the residential and the industry sector [13]. Figure 2.1 shows the development of district heating consumption in Sweden from 1970 to 2019. The figure shows how the industry has been growing steadily from 1970 but has started to level out.

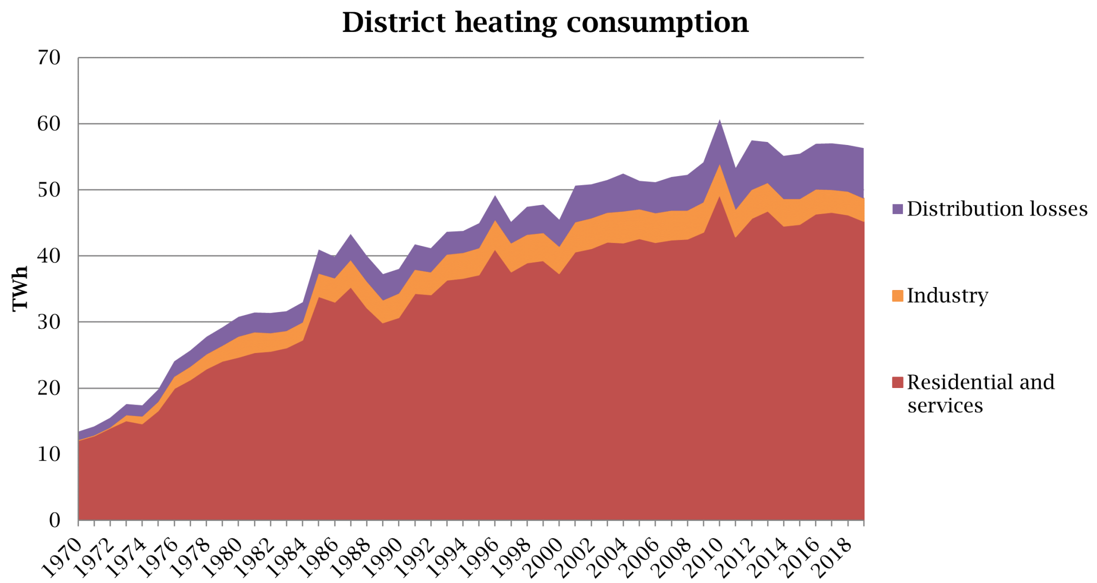


Figure 2.1: *District heating consumption from 1970 to 2019 according to the Swedish Energy Agency [13]*

Over 70% of Sweden's heat production comes from either biomass fuels like pellets and wood chips or waste heat, while less than 5% comes from fossil fuels like natural gas and coals [13]. The majority of the DH sector in Sweden is therefore renewable based.

2.1.1 DH market

Since the first DH system was introduced in Sweden in 1948 in Karlstad, the market share of DH has increased steadily from year to year where it currently stands at around 55%, leading the market compared to other types of heat sources [8]. Most cities and towns in Sweden have DH systems installed. Figure 2.2 shows how the supply of heat to buildings in Sweden has developed over the years. The figure shows how heating from oil has decreased to almost zero while DH and HPs have been increasing. From the figure, it can be understood how the biggest competitor of DH are HPs as they have been increasing steadily since 1990. In addition, the figure shows how electric heating started to decrease when HPs were introduced into the market. The oil crisis in the 1970s and 1980s was the source of why HPs started to develop in Sweden, which later led to HPs being funded through the Swedish Council for Building Research and promoted by the government [14]. This explains why HPs started to increase at the expense of electric heating.

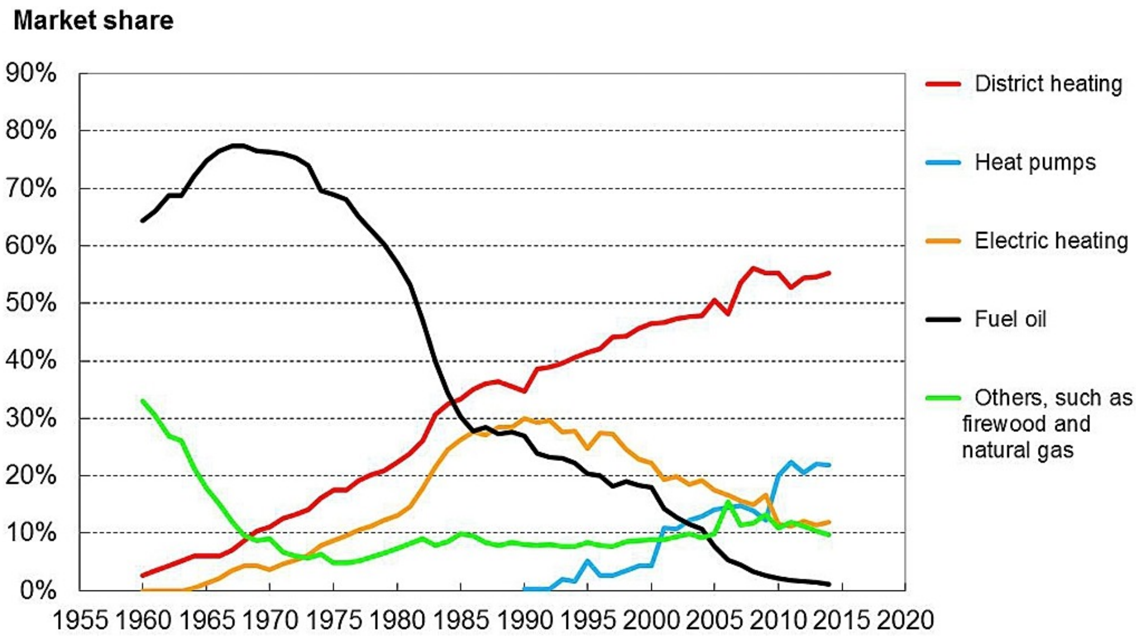


Figure 2.2: *Market share development of heat supply from 1960 to 2014. Figure from Werner [8]*

2.2 DH price models

Price models are the way DH companies charge their customers for supplied heat. A price model can be set up in many ways where different cost components can be included in different combinations. Frederiksen and Werner [4] talk about two different types of price models; a cost-based one and a market based one. In a cost-based price model, the revenues should cover the annual costs and some part of the company's capital cost. On the other hand, a market-based price model is when the price model includes a market price for market alternatives which in DH would often be natural gas. Market-based pricing can only be used when the market share of DH is low since with a high market share, the competition becomes almost none and will therefore not make any sense [4]. A cost-based price model can therefore be considered to be regulated while the market-based one would be de-regulated, as it allows for competition between heat sources.

Variable heat demand and a high share of fixed assets are the sources of economic risks for DH companies. To reduce this risk, the price models in Sweden have in recent years been moving towards being more cost-based [9]. Sernhed et al. [9] mentions three key factors in these new price models; a higher share of fixed costs, seasonal variation of energy cost, and that the customer should be charged for the needed capacity to fulfil his heat demand. There are many different ways to include these components in a price model, e.g. how capacities are estimated or how many seasons are included. A study performed by Ottosson et al. [15] in 2020, where 80 district heating companies were included, showed that 65% of the companies included seasonal variations in their price model when charging for energy, while almost all of them included a power component of some sort.

As mentioned above, the share between fixed and variable costs is an important thing to look at when looking into the performance of a price model, or in other words, it would be a key performance indicator (KPI) to determine if it is functioning well or not. More important KPIs for the price models would be for example to have small variation in the revenues between the years so the price models are more predictable, which would reduce the likelihood of the actual revenues being lower than the expected revenues.

2.2.1 Industry organization frameworks

Since there are no regulations regarding how DH companies charge their customers in Sweden, there are few organisational frameworks that all have the purpose of strengthening the customer's position and increasing the transparency of the price models. This subsection explains what the different frameworks do.

2.2.1.1 Prisdialogen

Prisdialogen (e. The Price dialogue) is an organization that aims to strengthen the customer's position when it comes to the price of DH. The outcome is a more stable, reasonable and predictable price model. When a DH company is part of Prisdialogen, it needs to report its price changes to Prisdialogen [16]. Therefore, the customers get a chance to give feedback on proposed changes so that the changes are not unreasonable to the customers. There are 35 DH companies in Sweden, part of Prisdialogen, and 29 of them are included in a survey that was performed in this thesis and will be explained in chapter 3 and the results will be presented in chapter 4.

2.2.1.2 Reko fjärrvärme

Reko fjärrvärme (e. Reko district heating) is an organization that started as an initiative with the aim of building relationships between the customers and the DH companies. Initially, it started as a certification organization, but as legislation and Prisdialogen have developed, Reko fjärrvärme has done the same. It is now the name of the DH industry's guidelines for customer relations. Reko fjärrvärme started in the early 2000s as a collaboration between the real estate and housing industry's partner organizations [17]. According to Energiföretagen [17], the organization is built on three principles:

- Transparency in accounting, which allows customers to assess suppliers' operations and products
- Comparability to enable well-founded assessments of various DH suppliers and local competing alternatives
- Mutual trust between supplier and customer to develop long-term relationships and enable well-founded choices

It is always voluntary to be connected to a DH network as well as the connection must be confirmed in written agreements. A Reko fjärrvärme supplier does not enter into unilateral agreements that only bind the customer and not the supplier. Each agreement is unique, and if any party is replaced, a new agreement must be entered into [17].

2.2.1.3 Nils Holgersson rapporten

Nils Holgersson rapporten (e. The Nils Holgersson report) is a report which is published annually. In the report, facts are reported about price differences between different municipalities in Sweden, among other things. The information contributed to the report comes from several different companies: Svenskt Vatten, Avfall Sverige, Energimarknadsinspektionen and Energiföretagen Sverige. The DH companies have responded to the report by changing their prices if needed, so the report has been beneficial for the customer's of the DH companies. The Nils Holgersson Group wants the report to create debates which hopefully lead to a reduction in prices for the customers [18].

2.2.2 Cost components

There are different cost components in price models, which all serve a different purpose. To better understand how a price model works, the different cost components that are frequently included in a price model will be explained in this section. Frederiksen and Werner [4] highlight four different components that are commonly used in price models; fixed cost, energy cost, power cost and flow- and return temperature (RT) cost.

Fixed cost

The fixed cost is simply a yearly cost of being connected to the grid (SEK/year), charged monthly. Since the component is fixed, it is independent of the actual heat delivery to the building. A fixed cost component is therefore independent of weather changes when it comes to cash flow which thereby reduces the risk of decreased profit when there are annual deviations in heat delivery [4]. That could happen, e.g. if the outdoor temperature is warmer than expected.

This cost component is more common for villas than for company-owned buildings. Due to that reason, it was decided not to include this component in any of the price models analyzed in this thesis. In addition, including a fixed cost in the studied price models would simply add a fixed factor directly related to the assumed value of the component to all the results from the price models and would therefore not add any specific value to the results.

Energy cost

A common component to include in a price model for district heating is the energy cost which can be described as the price that the customer pays for each unit of heat that gets delivered to the building. The energy component is a variable cost component which is commonly charged as SEK/MWh. Many companies let the energy price vary between seasons, which then matches better the production costs since more expensive fuels are typically used during winter when the heat demand is high [4]. A common and realistic way is to include three seasons; winter, summer and spring/autumn since it reflects well the marginal cost of heat production [19]. The component can even vary throughout the day, where it has high price hours and low price hours to better meet the production costs of the district heating.

Power cost

Another common component to include in price models is a power cost which can be described as the cost of the capacity needed for the customer, commonly charged as SEK/kW. The capacity size is usually estimated every year, where often, last year's usage is used for estimation. The component can therefore be considered as a fixed cost which, as Frederiksen and Werner [4] explained and was mentioned earlier, decreases the profitability risk of the company when the heat delivery is less than expected. However, if the component is estimated yearly, the component is, in fact, fixed during the year but will vary in the long run [19]. The component often consists of two parts, though; a fixed yearly cost (charged monthly) and a regular variable cost, which was just explained, and a yearly fixed cost. Figure 2.3 shows an example of how a DH company in Sweden defines their power cost component. [4].

There are different ways to estimate the size of the needed capacity. However, common approaches are to either measure the highest daily average power needed in the last 12 months or to measure the power needed during a cold day. The companies that include the fixed yearly cost in the power cost component usually let the price increase as the capacity increases. On the other hand, the variable cost usually decreases as the capacity increases since there are higher cost responsibilities for customers with small heat demand since the cost of infrastructure is always high [4]. This also strengthens the reasoning of why villas which usually have lower heat demand, often are charged based on a fixed cost only, as explained above.

Three-day mean power [kW]	Fixed price [kr/yr]	Variable price [kr/kW, yr]
0-100	9 235	880
101-250	14 285	830
251-500	28 090	775
501-1 000	58 150	715
1 001-2 500	123 215	650
> 2 500	298 285	580

Figure 2.3: *Example of a power cost component from a price model in a DH company in Sweden. The header of the table has been translated from Swedish to English*

Flow and temperature cost

These two terms are directly related since high flow usually means high return temperature (RT) from the customers' substation. This component encourages the customer to use the hot water from DH efficiently, which can be obtained by having a well maintained heat exchanger (HX). It is common to charge a fixed cost for each cubic meter that flows through the substation (SEK/m^3), which means that the customer can directly affect the price paid by reducing the flow. If RT is used instead of flow, it is common to charge for each degree difference multiplied by the amount of energy (SEK/(°C*MWh)). Another option is also to give discount for low flow or RT. By doing so, the customer can reduce the bill by having a good HX in the substation.

2.3 Heat pumps

A HP can be used as an alternative to DH for heating of buildings. It provides heat by extracting heat from an external, local source and transferring it into the building. The source can be, for example, outdoor or ventilation air, nearby groundwater or lake water, the ground or bedrock. Depending on which HP is chosen, the COP will vary as the temperature from the sources are different. How one chooses which type of HP to install depends on the heat demand of the house; if it is low, an air source heat pump might be enough, while if it is high, sources that have more stable temperatures throughout the years like the ground or lake might be more suitable [20]. As this thesis focuses on company owned buildings, the focus will be on ground source heat pumps (GSHP). Schematics of three different GSHPs can be seen in figure 2.4.

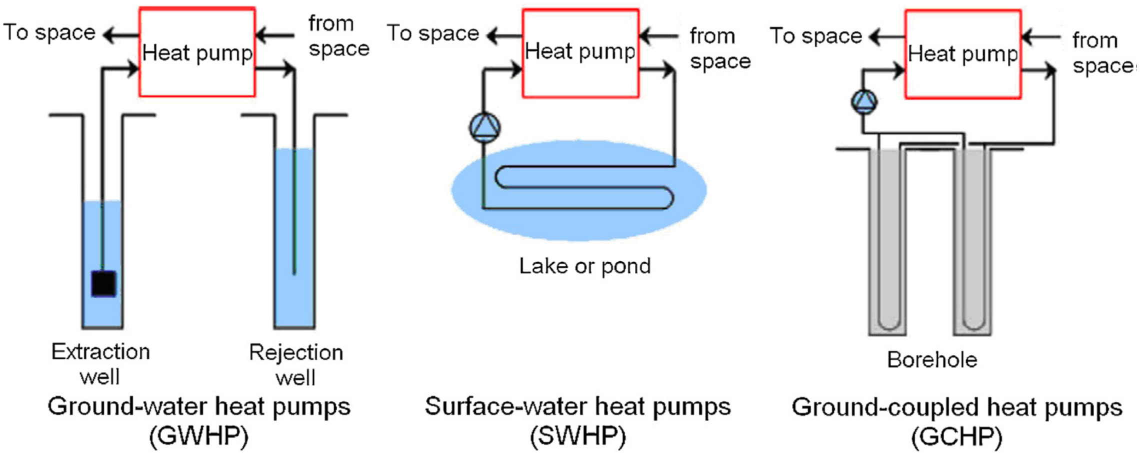


Figure 2.4: *Basic schematics of different types of GSHPs. Figure from Sarbu and Sebarchievici [21]*

The COP of a HP can be described as the ratio between the useful energy and the energy input into the HP [21]. That tells us that if the COP of the HP is 3.0, three units of heat will be delivered to the building for each unit that is put into the HP. So it is clear that a HP is much more efficient than using e.g. direct electricity to heat up the building, which could be considered having COP of 1.0, as a comparison. Sarbu and Sebarchievici [21] mentions that the GSHP has become more popular recently as it has good efficiency and is a good environmental choice. The heat in the ground is in general warmer than the heat of the outdoor air during winter and colder during summer, which results in good efficiency.

The European Heat Pump Association (EHPA) mentions that Sweden is in 4th place in Europe having the most number of HPs installed[22]. According to the EHPA [22], 112,000 HPs were sold in Sweden in 2020. The number of HPs in Europe have grown from 84 thousand to 1.6 million from 2007 to 2020 which highlights how they have been increasing fast over the years. The association expects that by 2024, the HP market will double which would lead to significant reduction in GHG emission. These facts highlight how HPs are the biggest competitor of DH companies.

3
Method

This chapter describes the method applied in the study. The years of 2009-2021 were modelled to get a good range of different weather scenarios. Three DH companies provided data to the thesis and hence, were the three networks included and modelled in the study. The networks will be referred to as network A, network B and network C throughout the study to ensure anonymity. The results will therefore be based on real data from real DH networks.

3.1 Survey of today's price models

A survey of currently used DH price models in Sweden was performed to get a clear picture of how a common price model looks today. Data was collected from the 50 largest district heating companies in Sweden. The size order of the Swedish DH companies was assumed according to data published by Energimarknadsinspektionen [23], where the ones with the highest revenues were assumed to be the largest. The survey was done by looking up the present price model of these 50 DH companies, which was published on the companies' websites in all of the cases.

The results were classified into three main categories; energy, power and flow/RT. For the energy component, five different classifications were specified:

- No seasonal variation
- Two seasons (summer & winter)
- Three seasons (summer & winter & spring/autumn)
- Four seasons (summer & winter & spring & autumn)
- Base + peak times

Different price levels are used each of the seasons as the production costs are typically not the same due to different heat demand. No seasonal variations therefore simply means that the energy price is fixed throughout the year. The base and peak times is when instead of having seasons, hours that have demand over a certain limit, are considered as peak times and have higher energy price while the hours below the limit are base times and have lower energy price.

The power component was also categorized into five different categories:

- Measured power
- Power signature
- Subscribed power

- Power based on measured energy
- No information

The measured power is when the capacity is estimated based on last years measured usage, typically last years three to five largest peaks. Power signature is when the power demand of a building is described as a function of the outdoor temperature. When companies size the capacity based on power signature, a temperature limit representing a cold day has been chosen. The capacity size of each building will then correspond to that outdoor temperature. The chosen value of a cold day differ between companies as they have different geographical locations. The subscribed power is when the customers subscribe to a capacity size based on how much power they think they will need. Power based on measured energy is similar to the measured power previously described. The difference is that previous energy usage is measured and then divided by some hours to get the needed capacity.

Finally, four different categories were used for the flow/RT component, two for each type:

- Flow: Fixed cost
- Flow: Reward/penalty
- RT: Fixed cost
- RT: Reward/penalty

The fixed flow is simply when the customer pays for each cubic meter that goes through the substation. This type of component also exists in a reward/penalty way which is when the customer pays if the flow through the substation is higher than the system average flow and gets discount if the flow is below the system average. These two components also exist in a form where the RT is used instead of the flow. A common way is to choose one or two temperature limits and if the RT is higher then the limits, the customer pays according to that. If the RT is in a reward/penalty way, the RT of the substations are compared to the system average RT and provides either a discount or charge per consumed energy and degree.

3.2 Modelling of price models

This section aims at explaining how the price models included in the study were set up and modelled. In total, five price models were analyzed, where, in each one of them, only one price component was changed at a time to see clearly how that single component would affect the revenues and behave between years.

Utilifeed's pricing platform was used to do the calculations. It is a machine learning that takes in both meter data along with weather and calendar data from a chosen training year. The machine learning will model and learn the training years behaviour which then is applied and simulated to a chosen period of time along with the corresponding weather and calendar data. The simulation then allows us to compare the results between the years and gives us insight and information to make decisions. Since the machine learning includes all substations in the network in the training year, the results can be viewed on a single building resolution which allows us to look at the annual costs of each separate building. In this study, 2019 was used as a training year, to not let the COVID-19 pandemic influence the output. The years 2009 to 2021 were modelled to get a good range of different weather scenarios. Figure 3.1 shows an overview of how the machine learning platform works.

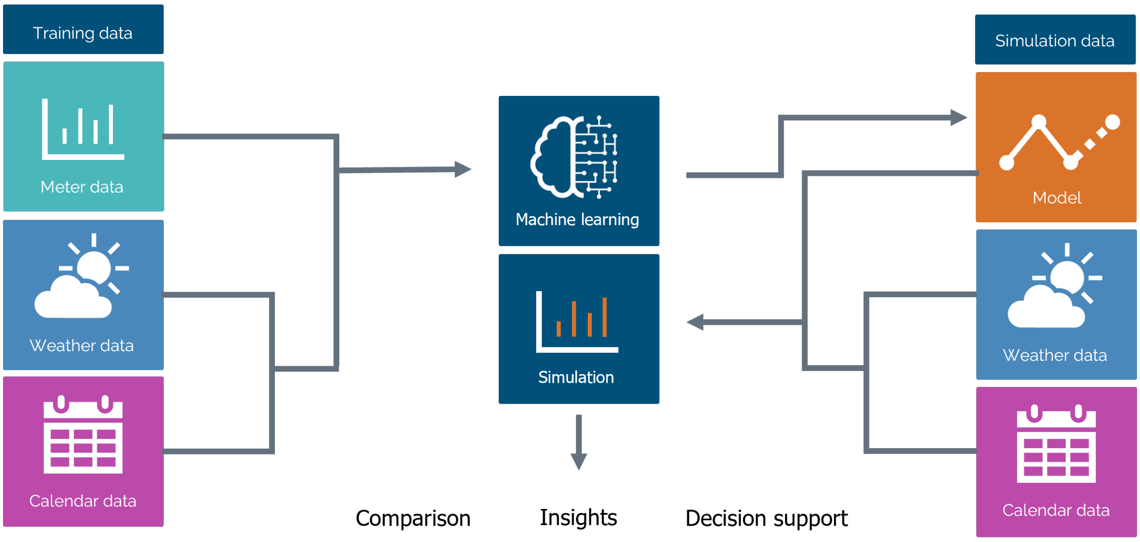


Figure 3.1: *Overview of Utilifeed's machine learning pricing platform*

Before setting up the price models, the first step was to calculate the degree days in all three networks to point out if there was a cold and warm year in the period 2009 to 2021. The degree days were calculated according to the base temperature Sveriges meteorologiska och hydrologiska institut (e. Swedish Meteorological and Hydrological Institute) (SMHI) uses, which was 17 degrees [24]. The degree day method assumes that during days where the average outdoor temperature is above the base temperature, there is no heating need in buildings. During all days where the temperature is lower than the base temperature, there is a heating need. It therefore tells how much heating was needed in each year. The equation is as follows

$$Degree\ days = \sum_{i=1}^{365} 17°C - T_{ave,i} \tag{3.1}$$

where i represents the day of the year and $T_{ave,i}$ is the average temperature during day i.

The upcoming sections aim at explaining how the five price models were set up in the pricing platform, as well as explain in detail how the prices for each component were assumed.

3.2.1 Price model 1 (PM1)

Based on the survey results, it was decided to begin with a price model which would be considered as a reference case which represents the most frequent components from the survey. The reference price model includes: an energy component based on three seasons; winter, spring/autumn and summer, a power component where the capacity size was measured based on the three most significant daily average peaks during the last 12 months and a third component, a fixed flow cost component.

Table 3.1 shows the assumed energy prices for each of the seasons. They were assumed by calculating the average energy price for each season for all the utility companies in the survey that included three seasons in their energy component in their price model. The definition of summer, winter, and spring/autumn was assumed based on these utility companies' most frequent definition.

Table 3.1: *Assumed energy prices for each season when the energy component includes three seasons*

Season (months)	**Energy price [SEK/MWh]**
Winter (Nov, Dec, Jan, Feb, Mar)	508
Summer (Jun, Jul, Aug)	324
Spring/autumn (Apr, May, Sep, Oct)	185

Table 3.2 shows the assumed prices for the power cost component, which changes as the measured capacity increases. The component contains two parts; a variable price which depends on the size of the capacity, and a fixed price which is the same for all capacities in the size interval and increases between intervals. The assumption of the values of the prices was a bit more complicated than when assuming the energy prices due to the component being more complex, i.e. having two parts and changing between sizes. Firstly, the average number of intervals was used along with a typical size of the intervals of the companies that included a power cost component in their price model. Next, it was calculated what the price of these size intervals would be for all the companies by looking at what the highest value in each capacity interval would cost in the price models of the companies. Next, the average cost of all of them was calculated and then divided by the capacity size. If we, for example, look at the first capacity interval, which is from 0 to 50 kW, it was calculated what 50 kW would cost in all of the companies and then the average value was calculated. Finally, that number was divided again by 50 kW, giving the assumed price for this interval. The same calculation was done for all of the five size intervals.

The average value of the smallest capacity interval was calculated when assuming the fixed price. For the remaining intervals, the value was set so that when the power cost was plotted against the installed capacity, it formed a continuous curve.

Table 3.2: *Assumed power prices for the price models. The fixed price increases with increased capacity while the variable price decreases*

Capacity [kW]	Variable price [SEK/kW]	Fixed price [SEK/yr]
0-50	917	9061
51-250	843	12761
251-1000	769	31261
1001-2500	695	105261
>2500	621	290261

The value of the fixed flow component was assumed similar to the energy prices or by simply calculating the average price of all the companies that included the fixed flow component in their price model, which was 3 SEK/m^3.

3.2.2 Price model 2 (PM2)

The second price model was set up so that both the energy and flow components were kept the same as in PM1. However, the power component was changed so that the capacity's size is estimated based on a cold day, i.e. power signature was included. The temperature which was used as a reference was -9°C. The prices of the power component were assumed to be the same as in PM1 as table 3.2 shows. The only difference between PM1 and PM2 is how each substation's capacity is estimated.

3.2.3 Price model 3 (PM3)

In the third price model, the flow component was changed to a RT component, so that a customer is charged higher if the RT from a substation is too high. In this model, the RT of each substation is compared to a set limit or limits that decides if the customer is to be charged extra for poor efficiency. The limit was assumed to be 30°C and 60°C which was common limits in today's price models that include a RT component. The chosen limits mean that if the RT from a substation was higher than 30°C, a fee was charged, and if it was higher than 60°C, an even higher higher fee was charged. The assumed values of the prices can be seen in table 3.3.

Table 3.3: *Assumed return temperature prices for PM3*

Temperature range [°C]	Price [SEK/(°C*MWh)]
< 30	0
30-59	2.3
≥ 60	20.5

3.2.4 Price model 4 (PM4)

The fourth price model looked at how it would affect the performance of the price model by having varying energy prices during the day; high demand prices from 06-11 & 17-22 and low demand prices at all other hours. The price was set so that the average of the high demand price and the low demand price would match the assumed energy price in PM1. The variable price only applies to the winter season since the heat demand is generally highest during that season which means that the production costs are at their maximum during those high demand hours and have the most significant environmental impact. The price during summer and spring/autumn were assumed to be the same as in PM1. The assumed energy prices can be seen in table 3.4.

Table 3.4: *Assumed energy prices for PM4*

Season	Energy price [SEK/MWh]
Winter	
- High demand hours: 06-11 & 17-22	530
- Low demand hours: Other hours	486
Summer	185
Spring/autumn	324

3.2.5 Price model 5 (PM5)

The last price model looked at the difference in having the energy component based on two seasons instead of three as the previous price models did. The prices were set so that when looking at the total energy cost during a year, the two-season model gave approximately the same value as when having three seasons. In other words, it tried to match the total revenues coming from the energy component in PM1, but instead, the monthly revenues would differ. The assumed energy prices when including two seasons can be seen in table 3.5.

Table 3.5: *Assumed energy prices for each season when the energy component includes two seasons*

Season	Energy price [SEK/MWh]
Winter (Nov - Mar)	517
Summer (Apr - Oct)	276

3.3 Evaluation of results

A number of key performance indicators (KPIs) were identified in order to evaluate the results. The first one was simply looking at the monthly revenues since the DH companies need revenues every month. The following KPI was the performance during warm and cold years since these are the extreme weather scenarios that could happen. When there is a warm year, the DH company risks losing revenues as the heat demand decreases, as explained in section 2.2.2. The share between fixed and variable costs was also identified as a KPI since the fixed cost is the predictable part of the company's upcoming revenues [4]. This would also be a KPI on the customer side since the variable cost is the potential for the customers to increase their efficiency and decrease their heating bill [9]. Another KPI was that the annual revenues should be high but the variations between years should be low. The last KPI was identified as the customer revenue change. This KPI means that all the customers should have a small change in their costs when changing the price model instead of a few customers having significant ones. The 15 buildings included in the HP calculations which will be explained in next section were used to estimate the customer revenue change. The customer revenue change will therefore be evaluated for one small residential building, one large residential building, one school, one office building and one industry building in the three networks, so five buildings per network. The 15 buildings therefore represent 15 random customers in the networks. Table 3.6 shows a summary of the selected KPIs and to whom it is beneficial.

Table 3.6: *Chosen KPIs for evaluation of the results from the price models*

KPI	Beneficiary
Monthly revenues	DH company
Performance during warm & cold years	DH company
Share between fixed & variable cost	DH company & customer
High average revenue but low variations	DH company
Customer revenue change	DH company & customer

In addition, two KPIs were identified that indicate if the system efficiency is good or bad. They are the share of flow cost component and the share of RT cost component since the lower these two components are, the better the system efficiency is.

3.4 Comparison with heat pumps in a selection of buildings

In order to see how HPs compete against DH in the networks, the annual costs of a typical HP for fifteen different buildings were calculated, five buildings per network: one small residential, one large residential, school, office and an industry building. These five categories were chosen to get broad spectrum of different heat loads. The chosen buildings were mostly picked randomly. The only requirement was that they had to have available meter data during all hours of the year. For clarification, the small residential building is not a villa, but an apartment building with few apartments.

To do the comparison, the annual costs of the HPs in the buildings, which includes the running costs and the installment costs were calculated and compared with what the customers would pay for DH. This was possible thanks to Utilifeed's pricing platform which calculates the DH costs of each building separately when calculating the total revenues of the DH companies. The HP calculations were performed in Python.

The running costs of a HP is mainly affected by the electricity prices and the COP of the heat pump. Therefore, in order to calculate the running costs of the HPs, the COP had to be assumed in some way as well as the electricity costs had be be estimated. It was decided to let the COP vary monthly according to the datasheet of a NIBE F1345 heat pump, which is a ground source heat pump available in a few sizes up to 60 kW. The datasheet of the HP gave the COP at four different outdoor temperatures, so in order to get the COP at all outdoor temperatures during the year, it was assumed to increase or decrease linearly. In addition, the COP was assumed to vary monthly, so the average outdoor temperature during each month in each network was used. Figure 3.2 shows how the COP varied over the year in all of the three networks.

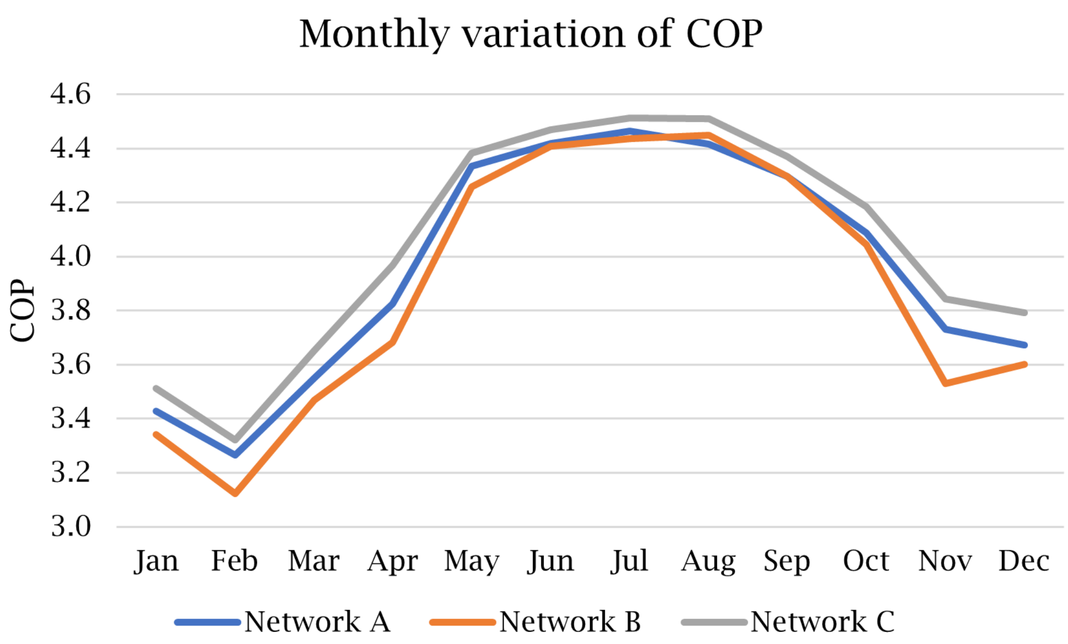


Figure 3.2: *Monthly variation of COP in the three networks*

As mentioned, the electricity prices also play a big role when calculating the running costs of a heat pump. Monthly electricity prices were collected from the historical average monthly NordPool spot prices for 2019. This year was mainly chosen since the machine learning of the DH price models used it as a training year as well as to make sure that the electricity prices were not being affected by the COVID19 pandemic. In order to get the price that the customer would pay for the electricity, grid fees, electricity tax, green certificate and electricity premium (SV. elhandelspåslag) had to be added. Equation 3.2 shows how the monthly electricity prices were calculated where i represents the months of the year.

$$El.\ price_i = Spot\ price_i + Grid\ fee + Green\ certificate + El.\ premium \tag{3.2}$$

The monthly spot prices can be seen in table 3.7 where the spot prices for two different districts are shown, i.e. two of the networks are located in the same pricing area and one of them is located in another one. The values for the remaining components; electricity tax, grid fees, green certificate and electricity premium are shown in table 3.8.

Table 3.7: *Electricity spot prices in 2019 from NordPool spot market*

	Spot price [SEK/MWh]
Jan	558.04 / 572.77
Feb	477.37 / 485.90
Mar	413.76 / 441.38
Apr	415.98 / 433.79
May	374.00 / 423.85
Jun	259.95 / 319.60
Jul	370.31 / 369.38
Aug	397.09 / 372.58
Sep	371.76 / 319.55
Oct	407.30 / 396.59
Nov	445.56 / 450.54
Dec	377.55 / 398.60

Table 3.8: *Value of price components that were added to the NordPool spot prices*

	Price [SEK/MWh]
Electricity tax	356
Grid fees	500 / 660
Green certificate	190
Electricity premium	182.4

The heat load data of the buildings in 2019 were collected from the data provided by the three DH companies to calculate the expected running costs of the HPs. During hours where the heat load was lower than the capacity of the heat pump, the following equation could be used

$$RC = \sum_i \sum_j \frac{El.\ price_i * Heat\ load_{i,j}}{COP_i} \tag{3.3}$$

where $El.\ price_i$ and COP_i is the electricity price and COP at month i and $Heat\ load_{i,j}$ is the heat load at hour j of month i. During hours when the heat load was higher than the HP capacity, the equation had to be adapted to add the cost of using direct electricity for the remaining heat load after the heat pump had been fully utilized. That was done using the following equation

$$RC = \sum_i \sum_j \left(\frac{El.\ price_i * Cap_{HP}}{COP_i} + El.\ price_i * (Heat\ load_{i,j} - Cap_{HP})\right) \tag{3.4}$$

where Cap_{HP} is the capacity of the heat pump at 55% of the maximum load of the building. The running costs are only dependent on the electricity prices and the COP of the HPs, so the cost does not include maintenance.

After calculating the running costs of the HPs in the buildings, they were compared to the annual costs of the previously calculated price models, where the price model with the highest DH costs would give the customer the most significant potential for investing in a heat pump. This price difference represents what could be spent yearly on a heat pump, or the annual savings. The capacity size was multiplied by 13 kSEK/kW for buildings with HP capacity >20 kW and by 14 kSEK/kW for buildings <20 kW, according to a common rule of thumb used to get the total investment cost (IC_{total}). This number includes the cost of the heat pump, the installation cost, and the cost of the borehole. In order to get an indicator of if the investment is a risk or not, the payback period (PBP) was calculated using equation 3.5. It is important to note that this equation does not consider money's time value and is only an initial indicator.

$$PBP = \frac{Annual\ savings}{IC_{total}} \tag{3.5}$$

In order the include the time value of money, the annual net profit value (NP_a) had to be calculated. The NP_a represents the annual savings that would be done by doing the investment and was calculated using the following equation

$$NP_a = Annual\ savings - IC_{total} * Af \tag{3.6}$$

where IC_{total} is the total investment cost and Af is the annuity factor which is the factor that brings the time value of money into the calculation. The latter of the equation represents the annualized investment cost. The annuity factor was calculated using the following equation

$$Af = \frac{r}{(1 - (1 + r)^{-T})} \tag{3.7}$$

where r is the assumed interest rate, 0.05, and T is the lifetime of the heat pump, which is around 15 years according to Rawlings and Sykulski [25] and [26].

4

Results and Discussion

This chapter aims to both present and discuss the results of the thesis. Firstly, it presents the results from the survey of today's price models. Next, the price model analysis results are presented and discussed in detail, and finally, the chapter will end with the heat pump comparison results.

4.1 Survey of today's price models

4.1.1 Energy cost component

The survey showed how the energy cost component was included in all of the price models that were part of the survey. By looking at figure 4.1, it can be seen that 46% of the companies had a seasonal variation of three seasons in their price model, while 24% and 20% had two seasons and one season, respectively. As we can also see, few companies even include four seasons in their price model, while some have base and peak times instead of defining specific seasons. The share of companies having no seasonal variation is still significantly high. However, 80% of the companies have some sort of variation in the energy price, which is still a high share.

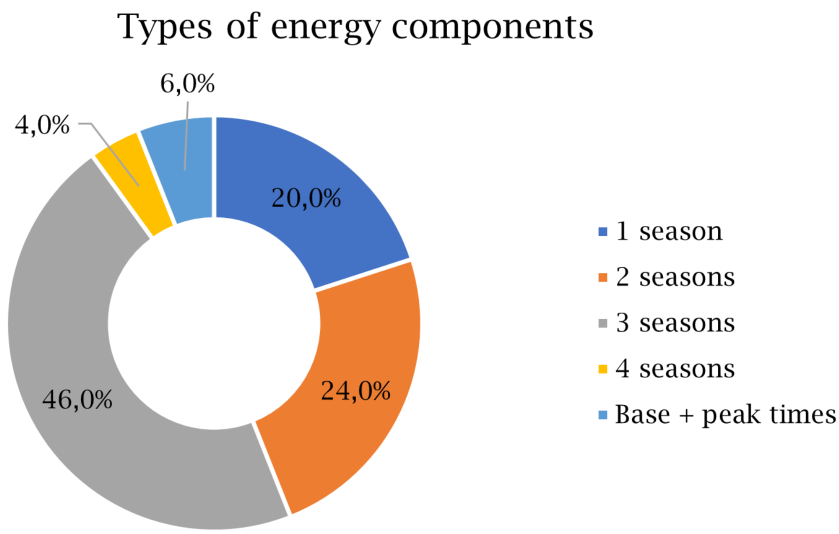


Figure 4.1: *Share of the different types of energy components from the survey*

4.1.2 Power cost component

92% of the companies in the survey included a power cost component of some sort in their price model. Figure 4.2 shows the results for the power cost component, where it can be seen that the majority sized the capacity based on previously measured data, or 47.8%. An example of a common way was to look at last year's 3-5 largest peaks and size the capacity based on that. The second most common way of sizing the capacity was to estimate the capacity's size based on power signature, i.e. based on a cold day. The chosen reference temperature for this type of component varied between companies since they are located in different places in Sweden and hence, have different outdoor temperatures.

The third most common way of estimating the size of the power component, accounting for 15.2%, was to size it based on previously measured energy usage, which then was divided by some number of hours to get the capacity. It could be claimed that this component would not define as a power component but rather that it is another type of energy component. However, it was still decided to keep it there in the survey to show clearly the percentage of companies that define their power component this way. Few companies had subscribed power where the customer subscribes to an estimated size and few had no information.

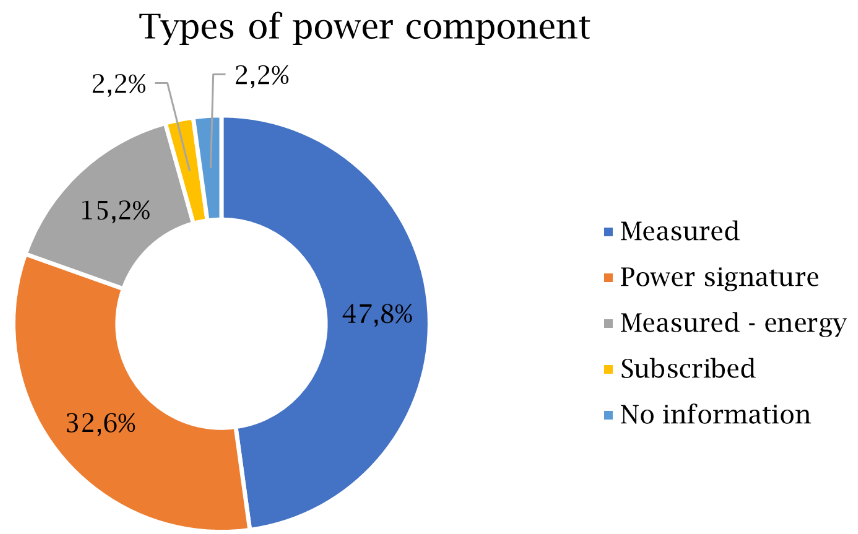


Figure 4.2: *Share of the different types of power components from the survey*

4.1.3 Flow/RT cost component

The survey showed that 68% of the companies included either a flow cost component or a RT component in their price model. Out of these companies, 65.6% of them included it as a fixed flow component, as shown in figure 4.3. The second-largest share, accounting for 18.8%, was when the flow component had a reward or penalty cost. It usually depended on whether the substation flow was above or below the system average flow. Therefore, the customer is either charged extra or gets money back from the company, depending on if he is above or below the system average.

The two remaining cost components accounting for 9.4% and 6.3% share, were quite similar to the flow components previously explained, but instead, they were based on the RT of the substations. A common threshold limit was to charge the customer if the RT was above 30°C and even more if above an even higher temperature, e.g. 60°C.

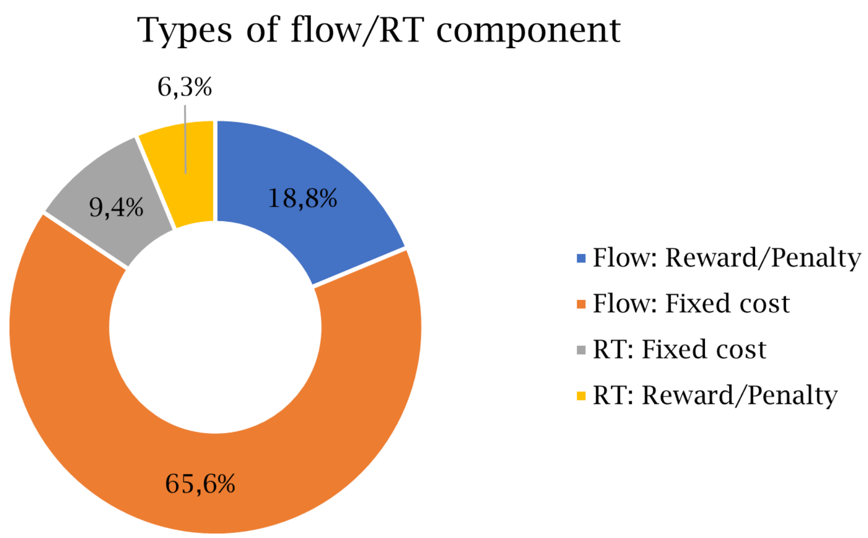


Figure 4.3: *Share of the different flow/RT components from the survey*

4.2 Price models

This section presents the results of the five different price models included in the thesis. Before presenting the results from each network, the calculated degree days used to see which year was cold and which one was warm are presented since these years are the extreme years for the DH company and, therefore, quite critical.

Figure 4.4 shows the calculated degree days in all of the three networks. As we can see, all of them had their maximum degree days in 2010, which means that this year was cold and more heating was needed. On the other hand, if we look at when the least amount of heating was needed, they all have a low value in the year 2020, which means it was a warm year. Network A had its lowest value in 2014, but since it was so close to the value in 2020, the latter was chosen to be considered a warm year for simplicity when comparing the results of the three networks together. Interesting thing to point out is that according to figure 4.4, the average temperature has been increasing in all of the areas over these years as the degree days have been decreasing. This indicates that the heat demand also should have decreased over the period.

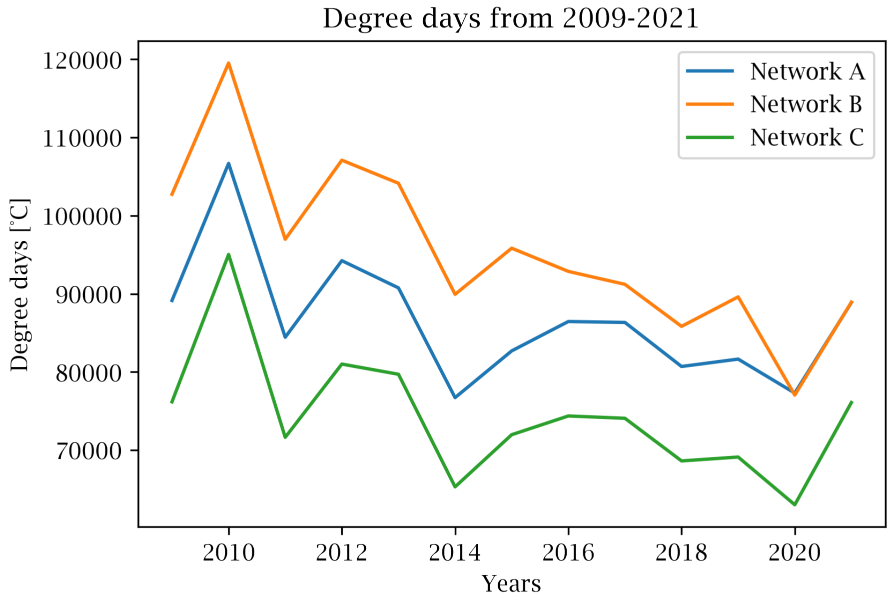


Figure 4.4: *Degree days from 2009 to 2021 in all of the three networks. The higher the value is the colder it was outside that year*

4.2.1 Network A

Table 4.1 shows a summary of the total annual revenues for each price model from 2009 to 2021, along with the share between the fixed and variable costs. The table has the cold and the warm years highlighted with blue and orange, respectively.

Table 4.1: *Yearly total revenues for network A when trying out the different price models along with the share between fixed and variable cost, presented as (F/V), where F stands for fixed cost and V stands for variable cost*

	Total revenue [MSEK]				
Year	**PM1**	**PM2**	**PM3**	**PM4**	**PM5**
2009	461 (36/64)	449 (34/66)	435 (38/62)	460 (36/64)	462 (36/64)
2010	544 (35/65)	509 (31/69)	518 (37/63)	542 (35/65)	544 (35/65)
2011	477 (40/60)	442 (35/65)	451 (42/58)	476 (40/60)	478 (40/60)
2012	490 (38/62)	459 (34/66)	463 (40/60)	489 (38/62)	491 (38/62)
2013	488 (38/62)	456 (34/66)	462 (40/60)	487 (38/62)	488 (38/62)
2014	422 (37/63)	423 (37/63)	396 (39/61)	421 (37/63)	423 (37/63)
2015	431 (37/63)	430 (37/63)	403 (40/60)	430 (37/63)	421 (37/63)
2016	476 (38/62)	447 (35/65)	449 (41/59)	474 (39/61)	476 (38/62)
2017	448 (37/63)	440 (35/65)	421 (39/61)	447 (37/63)	448 (37/63)
2018	463 (37/63)	446 (35/65)	438 (39/61)	461 (37/63)	464 (37/63)
2019	432 (36/64)	429 (36/64)	405 (39/61)	431 (36/64)	432 (36/64)
2020	400 (35/65)	405 (36/64)	373 (38/62)	399 (35/65)	400 (35/65)
2021	474 (37/63)	457 (34/66)	447 (39/61)	472 (37/63)	473 (37/63)
Average	**462 (37/63)**	**446 (35/65)**	**435 (39/61)**	**461 (37/63)**	**462 (37/63)**

If we look at the average row at the bottom of the table, we can see that PM1, PM4 and PM5, have the highest revenues while PM3 has the lowest ones. It can be seen how PM3 has the highest share of fixed cost, which, as mentioned earlier, is a KPI for the DH company. However, judging from the revenues, it can be understood that this is happening since the system is quite efficient and has a low RT cost, decreasing the share of variable cost. PM2, which performs best during warm years, often has the lowest share of fixed costs which might be considered negative for the company. It is worth to mention though that the share of the fixed cost for PM2 is highly dependent on the chosen cold outdoor temperature, used to estimate the sizes of the capacities in the network, so this share could be increased by lowering this reference temperature.

To better visualize the numbers in table 4.1, figure 4.5 shows a graph of the results. It can be seen clearly how the maximum revenues are achieved during the cold year, regardless of which price model is looked at, while on the other hand, the minimum revenues are achieved during the warm year. PM2, which estimates the power component based on power signature, shows the highest revenues during the warm year, indicating that PM2 has the least risk when it comes to the revenues during warm years. This is an important thing to look at since, in general, the DH companies are at the most significant risk of getting little revenues during warm years since heat demand goes down.

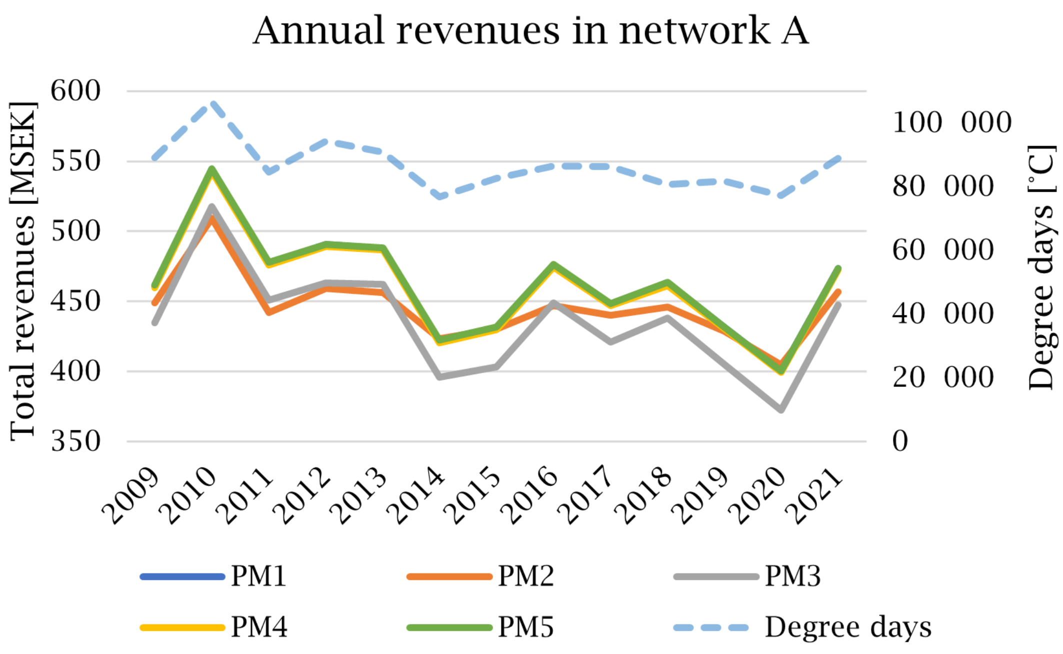


Figure 4.5: *Revenues from 2009-2021 in network A. On the secondary axis, the degree days over the years is shown*

PM3, which includes the RT in its price model, almost always results in the lowest revenues, which is a good indicator that the system is quite efficient, where many substations have RT below 30°C. If this price model would show high revenues, the system would most likely have many substations with high RT and could therefore be considered to have a pretty low system efficiency, or at least have room for improvements. Therefore, these results are quite positive for the company in question.

Another exciting thing is that PM1, PM4, and PM5 almost always show the same total annual revenues. In fact, the blue line, which represents the revenues for PM1, cannot be seen in the figure since it is always below the green or the yellow line. These results are actually quite good since it tells us that it should be possible to change the energy cost component in the price models without affecting the total revenues. Instead, the DH company could increase the flexibility of the system and better meet the production costs by either introducing more seasons in their price model or letting the energy price vary throughout the day.

Figure 4.6 shows the percentage change of the total yearly revenues from the average revenue year. It was decided to look at the deviation to see which price model had the highest deviations and which one had the lowest. It can be seen that PM2 has the smallest variations and is, therefore, the most stable price model over the years, which would make it easier to predict upcoming revenues. In contrast, the four remaining price models vary more and are therefore less predictable between years. As expected, the extreme years 2010 and 2020 have the highest variations, where 2010 has a maximum per cent change of 18.91% (revenue increase) while 2020 has the maximum per cent change of -14.45% (revenue decrease). Even though all price models except for PM2 have a similar pattern, it can be seen that PM3 has the highest deviations since it is the highest price model in 2010 and the lowest one in 2020. It can also be seen from the figure that the year 2018 could be considered an average revenue year since all of the lines lie on the average line that year.

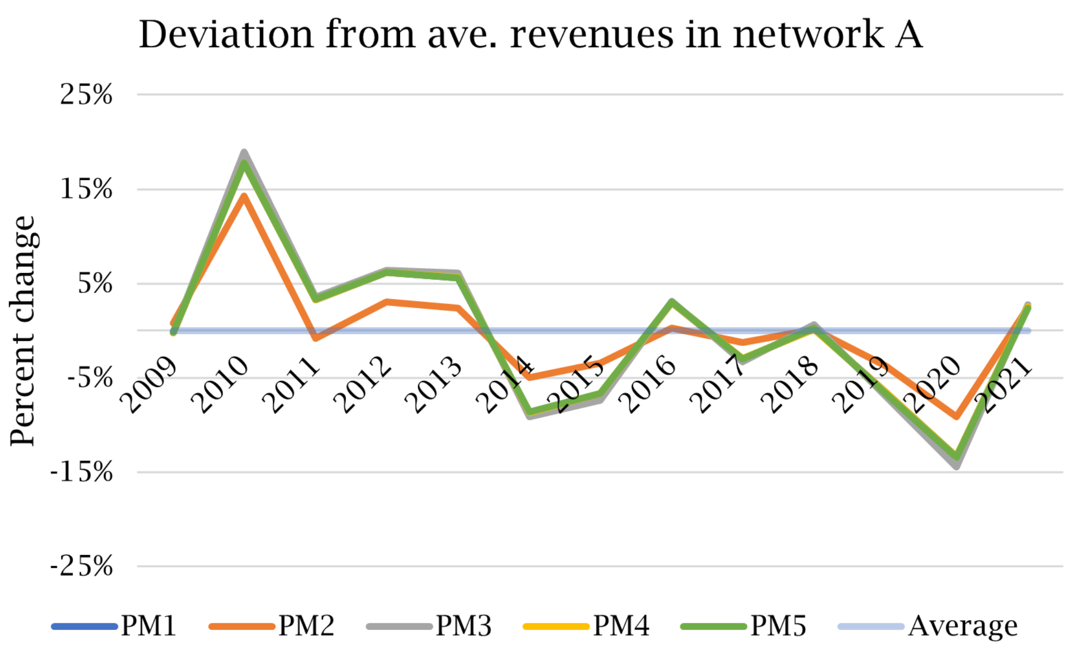


Figure 4.6: *Revenue change from 2009 to 2021 in the location of network A*

It was tried to see if there was any clear relationship between the annual revenues and the number of degree days by plotting them against each other. This can be seen in figure 4.7. The x-axis begins with the warmest year on the leftmost side of the axis and gets colder as we go more to the right. As we can see, there is some linear relation between the components, where the revenues are lower on the left side of the graphs and higher on the right side, but the relation is defiantly not purely linear, at least not in all of the price models.

The price models were plotted separately to see this better, as seen in the figure. On these plots, the R^2 value has been included to estimate the relation better. The closer the R^2 value is to one, the better the relationship between the components is. Looking at the R^2 values, we can see that PM2 has the best relationship between the two components, having an R^2 value of 8.984. Almost all the points fall on the trendline except for a couple of points that are slightly above and under the trendline. The remaining four price models all have lower R^2 value, so they do not have as good relationship between the two components. These results indicate that if a power signature is included in the price model, the revenues can be predicted more easily. Both because it has fewer deviations over the years and can be almost directly related to the degree days.

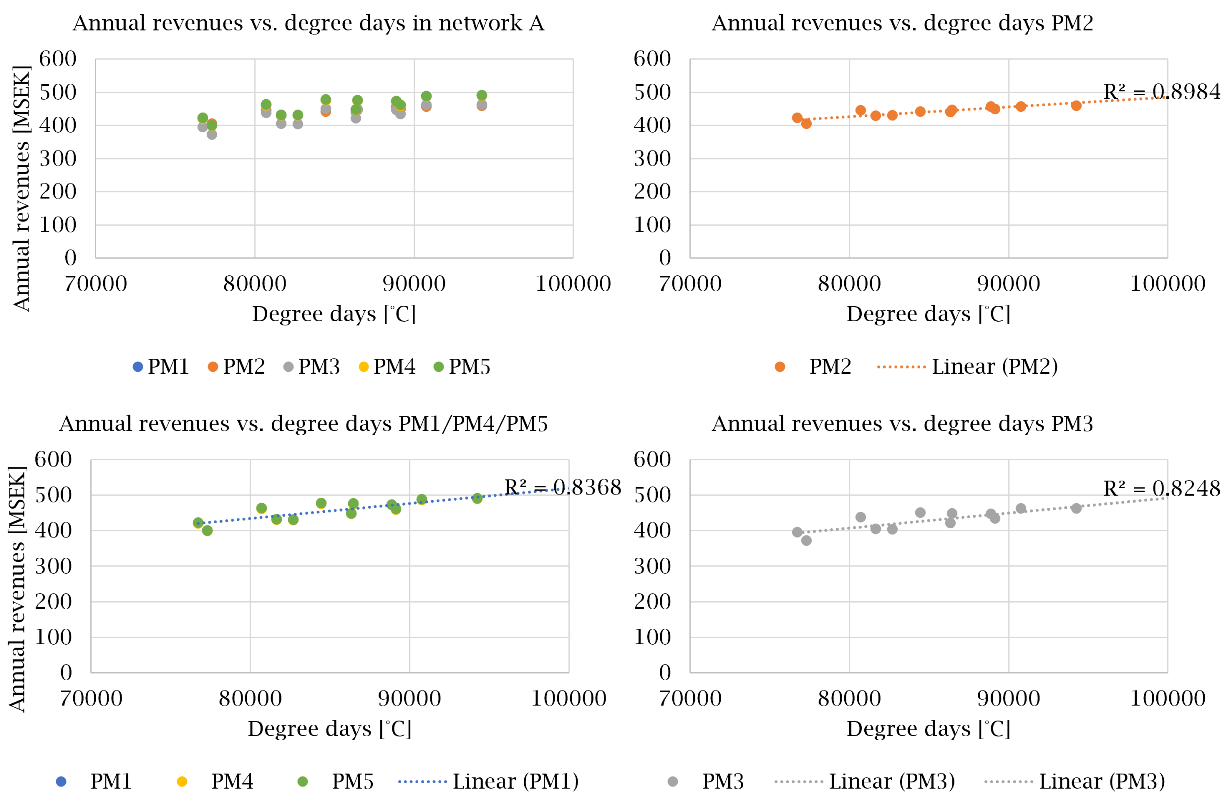


Figure 4.7: *Revenues vs. degree days in network A. The graph at the left on top shows all the price models combined in one graph while the remaining three show them separately to get a closer look at the trendlines*

The last KPI which has not been mentioned is the customer revenue change. Table

4.2 shows how the customer per cent change of annual total costs for five different buildings in network A when changing from PM1 to either of the remaining four price models. As we can see, changing from PM1 to either PM4 or PM5 does not affect the customers much. However, we can see that changing to PM2 would increase the cost of all of these customers, which is quite surprising since PM2 showed the lowest total revenues in the network. Changing to PM3 would decrease the annual costs for all of these buildings, which tells us that all these buildings have good RT. It can be understood from these results that it can be quite hard to predict how changing a price model will affect single customers.

Table 4.2: Customer revenue percent change for five different buildings in network A

	Customer percent change in network A				
	PM1	**PM2**	**PM3**	**PM4**	**PM5**
Small res.	Ref.	2.62%	-5.23%	-0.15%	0.00%
Large res.	Ref.	10.17%	-40.70%	0.00%	-1.45%
School	Ref.	14.53%	-59.59%	-2.91%	-4.36%
Office	Ref.	7.27%	-40.70%	0.00%	8.72%
Industry	Ref.	27.62%	-46.51%	-1.45%	-1.45%

4.2.2 Network B

A summary of the annual revenues from the five price models in network B in 2009-2021, along with their share between fixed and variable costs, can be seen in table 4.3. As we can see, this network has much higher revenues than the previous one, which the size difference between the networks can explain. Again, the cold and the warm years have been highlighted with blue and orange, respectively.

From the average value, it can be seen that PM3 gives, on average, the highest revenues as well as showing quite high share of fixed costs, or 34%. Again. PM1, PM4 and PM5 perform pretty similarly, which emphasizes the results showing that increased flexibility can be reached without affecting the total revenues too much. It can be seen how all the price models have a similar share of fixed and variable costs, where the fixed share accounts for around 34%. PM2 has, again, the lowest share of fixed costs. However, it is interesting to see how network A had higher shares of fixed costs in all of the five cases compared to this one.

Again, to visualize the results better, they were plotted on a graph which can be seen in figure 4.8. The same pattern can be seen in network A, where the highest revenues were in 2010 when it was a cold year and the lowest ones in 2020, when it was warm. It is interesting to see here, though, that all the price models perform very similarly during the warm year. By looking closely, it can though be seen that PM2 gives slightly higher revenues, which was also the case in network A.

Table 4.3: *Yearly total revenues for network B when trying out the different price models along with the share between fixed and variable cost, presented as (F/V), where F stands for fixed cost and V stands for variable cost*

Year	Total revenue [MSEK]				
	PM1	PM2	PM3	PM4	PM5
2009	1259 (33/67)	1213 (30/70)	1271 (32/68)	1256 (33/67)	1262 (33/67)
2010	1477 (33/67)	1355 (27/73)	1507 (33/67)	1473 (33/67)	1481 (33/67)
2011	1280 (37/63)	1171 (31/69)	1289 (37/63)	1277 (37/63)	1284 (37/63)
2012	1289 (34/66)	1211 (30/70)	1300 (34/66)	1286 (34/66)	1291 (34/66)
2013	1304 (34/66)	1219 (30/70)	1318 (34/66)	1302 (35/65)	1306 (34/66)
2014	1166 (35/65)	1124 (33/67)	1169 (35/65)	1166 (35/65)	1169 (35/65)
2015	1150 (35/65)	1115 (33/67)	1153 (35/65)	1150 (35/65)	1154 (35/65)
2016	1232 (36/64)	1148 (32/68)	1238 (36/64)	1233 (36/64)	1234 (36/64)
2017	1112 (33/67)	1105 (33/67)	1113 (33/67)	1109 (33/67)	1114 (33/67)
2018	1198 (34/66)	1153 (31/69)	1206 (34/66)	1196 (34/66)	1201 (34/66)
2019	1155 (35/65)	1120 (33/67)	1158 (35/65)	1153 (35/65)	1157 (35/65)
2020	978 (34/66)	986 (35/65)	973 (34/66)	977 (34/66)	980 (34/66)
2021	1183 (34/66)	1145 (32/68)	1191 (34/66)	1181 (34/66)	1186 (34/66)
Average	**1214 (34/66)**	**1159 (31/69)**	**1222 (34/66)**	**1212 (35/65)**	**1217 (34/66)**

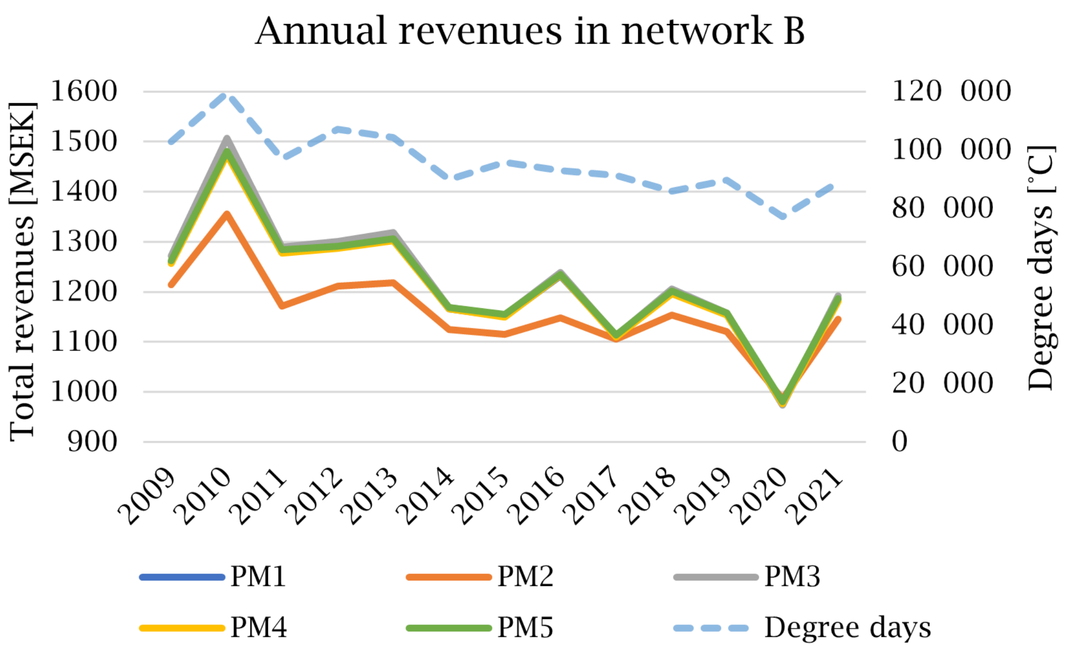


Figure 4.8: *Revenues from 2009-2021 in network B. On the secondary axis, the degree days over the years is shown*

One of the most significant differences between the results of networks A and B is PM3. It almost always shows the lowest revenues in network A, while in network B, it almost always shows the highest revenues. That indicates that the RT from many substations is relatively high, increasing the revenues of PM3. If this DH company would decide to include a RT component in their price model, the customers would likely react to the increased DH bill and, hopefully, try to improve the ΔT over their substation. This would eventually lead to PM3 showing more similar results as the one in network A, and the purpose would be achieved; to increase the system efficiency. This also explains why this network has higher shares of variable costs than network A; they have higher RT, which means that the flow must also be higher, which will increase the share of variable cost.

The per cent change from an average revenue year can be seen in figure 4.9. It can be seen how PM3 has the highest deviation, where it was at its maximum around 23.28% in 2010 and at its minimum around -20.37% in 2020. Again we can see how PM2 is the most stable one, which could be expected since the power cost component is based on a power signature instead of last year's usage and hence, does not change between years. The only thing affecting this component is the amount of heating needed, which will directly influence the energy and flow/RT component. We can again see how the extreme years, the cold and the warm years show significantly highest deviations. It can also be seen that 2018 was also an average year in network B, as in network A.

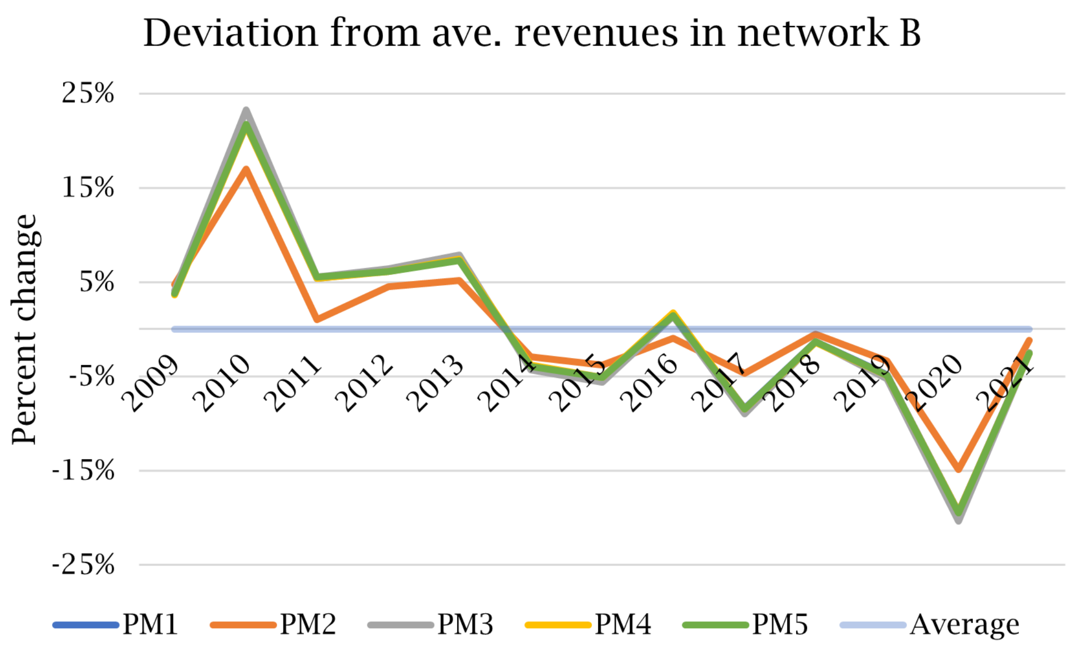


Figure 4.9: *Revenue change from 2009 to 2021 in the location of network B*

Figure 4.10 shows the annual revenues at corresponding degree days. The figure shows the results where all the price models are combined in one graph and show them separately to see if there is a linear relation. As we can see, the results show, in general, an increase from lower degree days to higher degree days, but the relationship differs between different price models. PM2 shows an apparent, direct linear increase in the revenues as the degree days increase, where the R^2 value is 0.8708. At the same time, the rest of the price models have a lower R^2 value and therefore less relation between the components. This lower R^2 value can probably be explained by the fact that in all price models but PM2, the power component is dependent on last year's usage and will therefore not necessarily represent well the degree days that particular year.

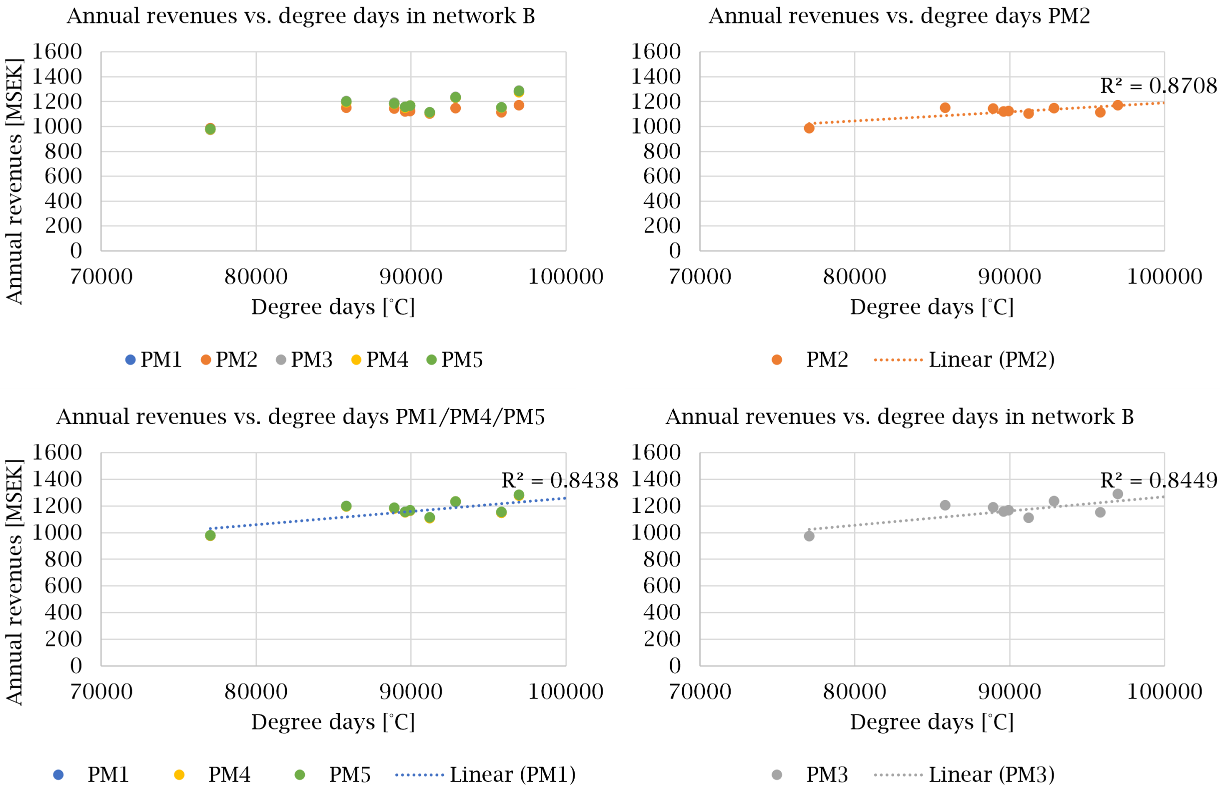


Figure 4.10: *Revenues vs. degree days in network B. The graph at the left on top shows all the price models combined in one graph while the remaining three show them separately to get a closer look at the trendlines*

Table 4.4 shows the customer revenue per cent change for five different buildings in network B when changing the price models. Again, changing from PM1 to either PM4 or PM5 has little impact on the price paid by the single customers for all of the buildings. Opposite to network A, PM2 result in lower revenues for these customers which could indicate that the chosen temperature for the power signature is slightly too low for this network. The degree days in figure 4.4 showed how network B was the coldest network which strengthens the theory. The small residential building is the only one that would save money if PM3 would be used which tells us that it has low RT while the other ones would get higher heating bill if PM3 would be used.

Table 4.4: Customer revenue percent change for five different buildings in network B

	Customer percent change in network B				
	PM1	**PM2**	**PM3**	**PM4**	**PM5**
Small res.	Ref.	-2.54%	-3.11%	-0.23%	-0.12%
Large res.	Ref.	-0.89%	10.49%	0.00%	0.00%
School	Ref.	-5.75%	-2.83%	0.00%	-0.94%
Office	Ref.	-3.48%	-0.87%	0.00%	0.00%
Industry	Ref.	-2.16%	-0.72%	-0.14%	-0.29%

4.2.3 Network C

Table 4.5 shows the total yearly revenues for network C from 2009 to 2021 and the share between the fixed and the variable cost. As before, the cold and the warm year are highlighted with blue and orange, where the blue represents the cold year while the orange represents the warm year. The last row, representing the average revenues over the years, shows that PM1 and PM5 show, on average, the highest revenues. However, PM4 also results in almost the same value, so these three price models can be considered to perform similarly and result in the highest revenues. Therefore, it can be concluded that, as in the previous two networks, PM1, PM4, and PM5 perform very similarly, which tells us that production costs can be better met without affecting the total annual revenues much.

Table 4.5: *Yearly total revenues for network C when trying out the different price models along with the share between fixed and variable cost, presented as (F/V), where F stands for fixed cost and V stands for variable cost*

	Total revenue [MSEK]				
Year	**PM1**	**PM2**	**PM3**	**PM4**	**PM5**
2009	220 (36/64)	218 (36/46)	209 (38/62)	219 (36/64)	220 (36/64)
2010	262 (35/65)	251 (32/68)	252 (36/64)	261 (35/65)	262 (35/65)
2011	226 (41/59)	213 (37/63)	215 (43/57)	225 (41/59)	226 (41/59)
2012	229 (37/63)	222 (36/64)	218 (39/61)	228 (38/62)	229 (37/63)
2013	232 (38/62)	222 (35/65)	222 (40/60)	232 (38/62)	232 (38/62)
2014	197 (37/63)	203 (39/61)	186 (39/61)	196 (37/63)	197 (37/63)
2015	198 (36/64)	205 (38/62)	187 (38/62)	198 (36/64)	198 (36/64)
2016	223 (38/62)	216 (36/64)	212 (40/60)	222 (38/62)	223 (38/62)
2017	207 (36/64)	211 (37/63)	196 (38/62)	207 (36/64)	207 (36/64)
2018	216 (37/63)	214 (36/64)	206 (39/61)	216 (37/63)	217 (37/63)
2019	199 (36/64)	206 (38/62)	188 (38/62)	199 (36/64)	199 (36/64)
2020	176 (35/65)	185 (38/62)	165 (37/63)	176 (35/65)	176 (35/65)
2021	216 (36/64)	214 (36/64)	205 (38/62)	215 (36/64)	216 (36/64)
Average	**215 (37/63)**	**214 (36/64)**	**205 (39/61)**	**215 (37/63)**	**216 (37/63)**

Figure 4.11 shows the results on a graph for better visualization. It is obvious from the graph how the maximum revenues are achieved during the cold year while the minimum ones are achieved during the warm year. Compared to previous two networks, more difference can be seen between the five price models during the warm year, where PM2 clearly results in the highest revenues. This indicates that the assumed outdoor temperature for the power signature does most likely fit this network quite well, while in the others, it could be a good idea to decrease it even further. Looking at PM3, it can be seen that this network most likely has relatively low RT from the substations as it shows low revenues for that price model throughout the years. The grey line follows the slopes of PM1, PM4 and PM5 almost perfectly, so the RT seems good regardless of the weather.

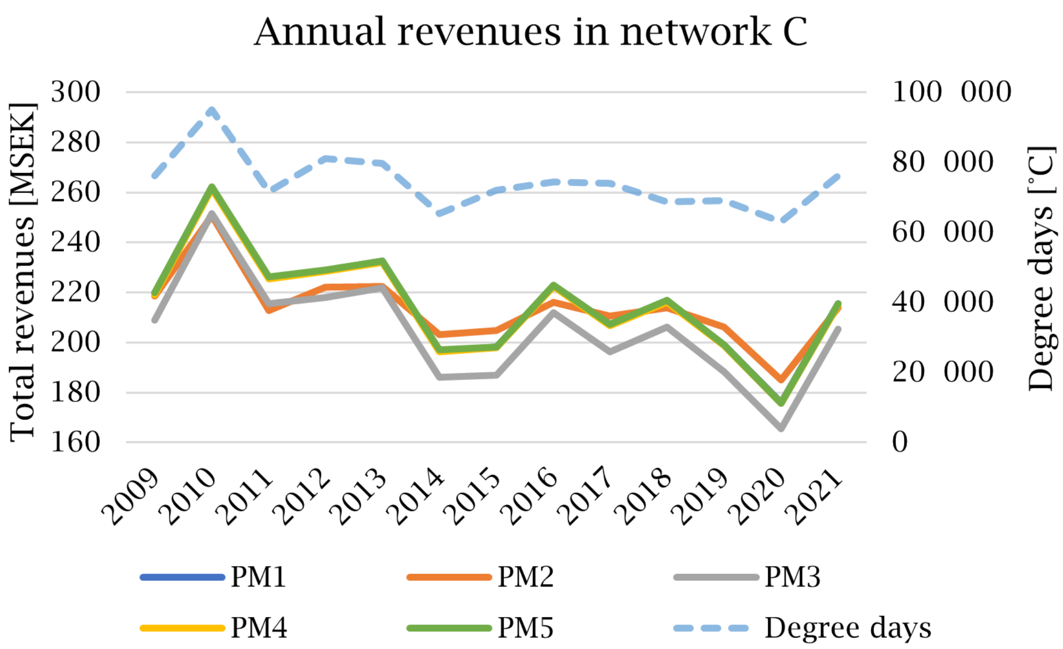


Figure 4.11: *Revenues from 2009-2021 in network C. On the secondary axis, the degree days over the years is shown*

The deviation in revenues from the average revenues can be seen in figure 4.12. As we can see, both 2018 and 2021 could be considered average revenue years, while the most significant deviations are achieved during the extreme years, 2010 and 2020 as in previous two networks. It can again be seen how PM2 is most stable while all the others deviate pretty similarly.

Figure 4.13 shows the relation between the annual revenues and the degree days. The figure shows how PM2 has the best linear relation between the annual revenues and the degree days as it has the highest R^2 value of 0.8929. As mentioned earlier, the closer the value is to one, the better the linear relation between the two components is. Similar results could be seen in networks A and B.

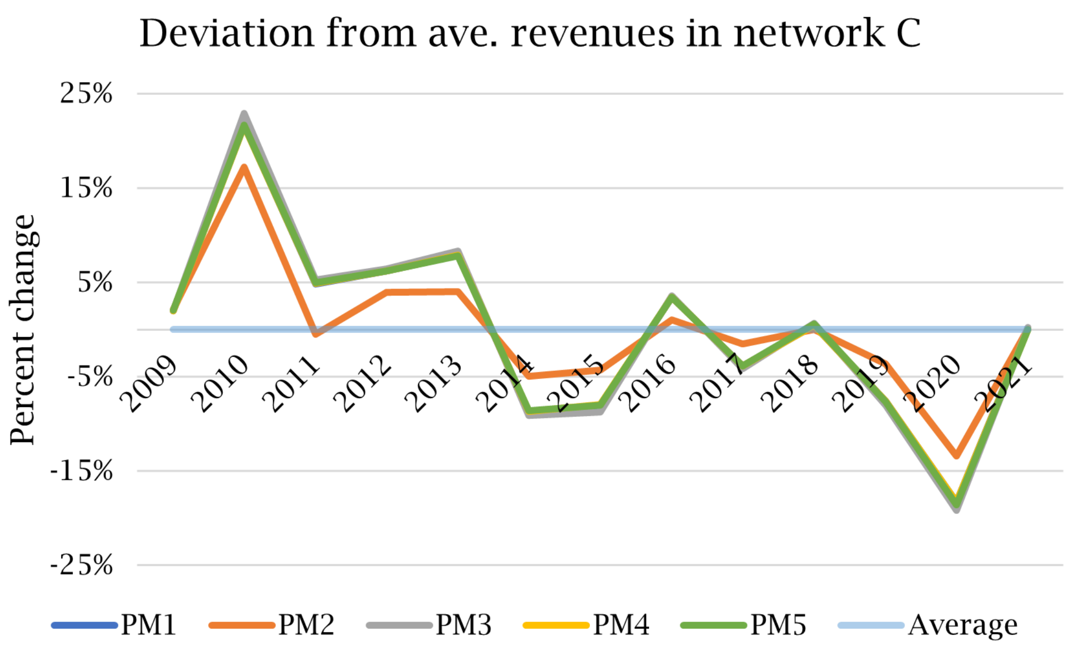


Figure 4.12: *Revenue change from 2009 to 2021 in the location of network C*

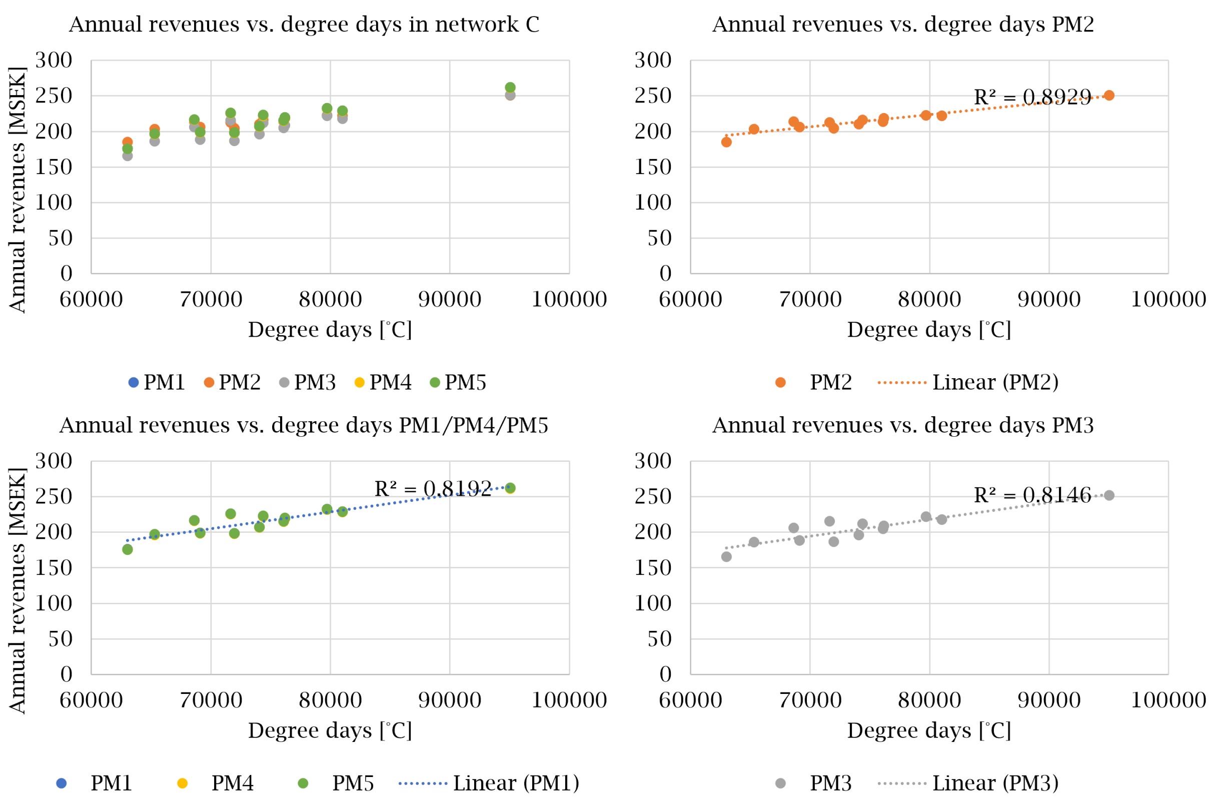


Figure 4.13: *Revenues vs. degree days in network C. The graph at the left on top shows all the price models combined in one graph while the remaining three show them separately to get a closer look at the trendlines*

As for the previous two networks, the revenues do not change much by switching from the reference case, PM1 to PM4 or PM5, which is good since the customer revenue change is one of the identified KPIs. All the buildings would pay less for the DH if PM3 were used, showing that they all have low RT and hence, are quite efficient. Changing to PM2 would increase the total annual cost quite much for all of the buildings, which is not what the DH company nor the customer would want. All the networks show how it can be hard for the DH companies to predict how changing the price models will affect single customers, at least not when changing either the power or flow/RT component.

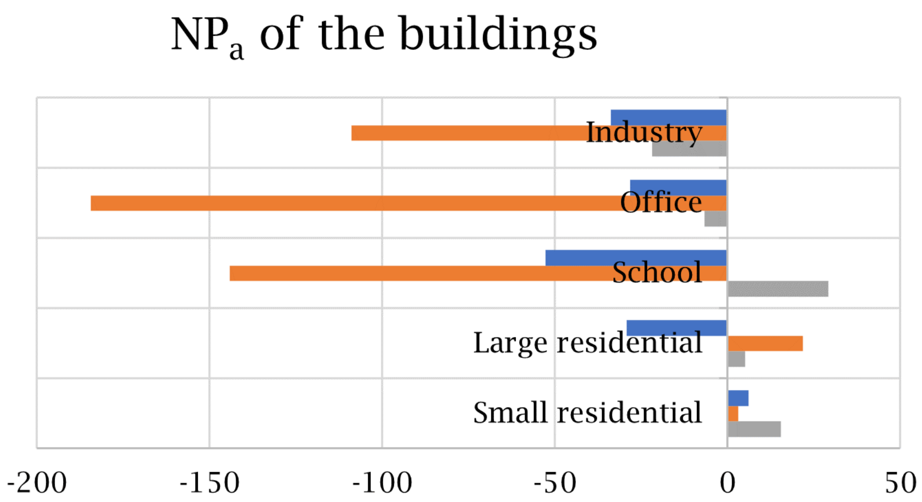
Table 4.6: Customer revenue percent change for five different buildings in network C

	Customer percent change in network C				
	PM1	**PM2**	**PM3**	**PM4**	**PM5**
Small res.	Ref.	3.62%	-10.11%	-0.15%	0.00%
Large res.	Ref.	4.59%	-5.46%	-0.22%	0.22%
School	Ref.	3.94%	-5.00%	-0.30%	-0.45%
Office	Ref.	5.82%	-4.45%	0.00%	0.00%
Industry	Ref.	3.17%	-3.27%	0.00%	0.00%

4.3 Heat pump comparison

This section presents the results of the HP cost calculations, which were performed to see how HPs compete against DH. The results presented in this chapter will show the main results for all buildings.

Figure 4.14 shows the annual net present value for all the fifteen buildings included in the calculations when the interest rate was 5% and the lifetime of the HPs was 15 years. Sensitivity analysis were performed on the assumed interest rate and lifetime of the HP and are shown in Appendix A. As we can see, six out of fifteen buildings show a positive NP_a, which means it should be worth it to invest in a HP for these buildings while the remaining nine buildings would not be profitable. The upcoming sections show the results for each building separately in more detail.



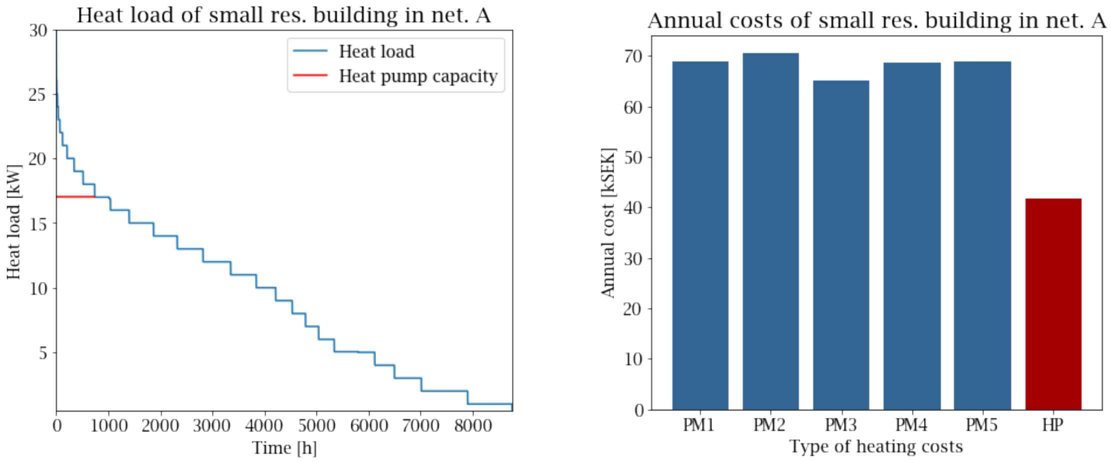
	Small residential	Large residential	School	Office	Industry
Network A	5.9	-29.1	-52.8	-28.3	-33.7
Network B	3.0	21.7	-144.2	-184.4	-109.0
Network C	15.5	5.1	29.2	-6.7	-21.8

NPa [kSEK/year]

Figure 4.14: *Annual net present value for all the fifteen buildings included in the HP calculations*

4.3.1 Small residential buildings

Figure 4.15a shows the heat load of the small residential building in network A. The needed HP capacity to cover 55% of the maximum heat load was 17 kW which would cover 97.34% of the building's total heat demand. By looking at figure 4.15b, it can be seen that the running costs of this HP would be relatively lower than the paid cost for DH in all of the five price models. However, this does not mean that the HP is necessary profitable since the customer also needs to invest in the HP and pay for installation and borehole costs. Also, operation and maintenance costs were excluded from the calculations so it is important to keep that in mind when looking at the results. The calculated PBP and NP_a of the investment were calculated as 8.25 years and 5.93 kSEK/year and can be seen in table 4.7.

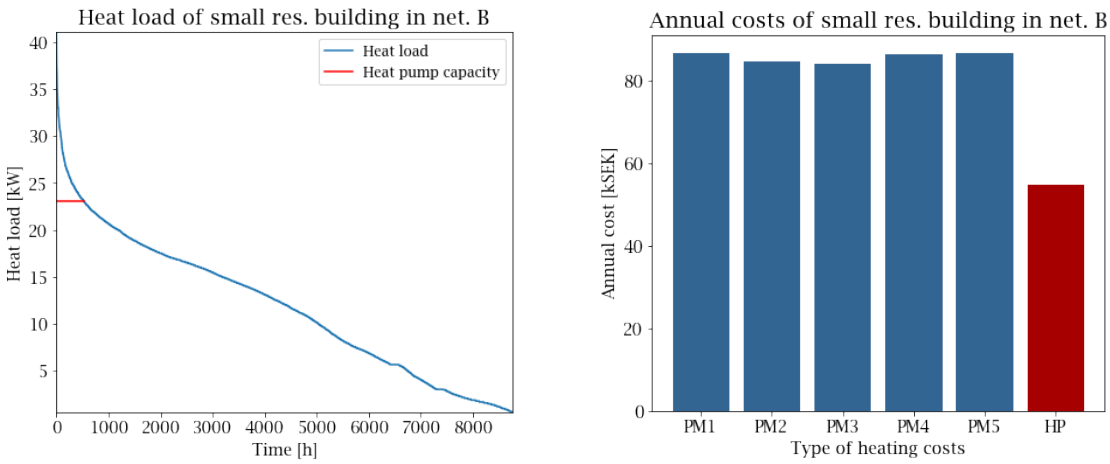


(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.15: *Heat load of a small residential building in network A along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

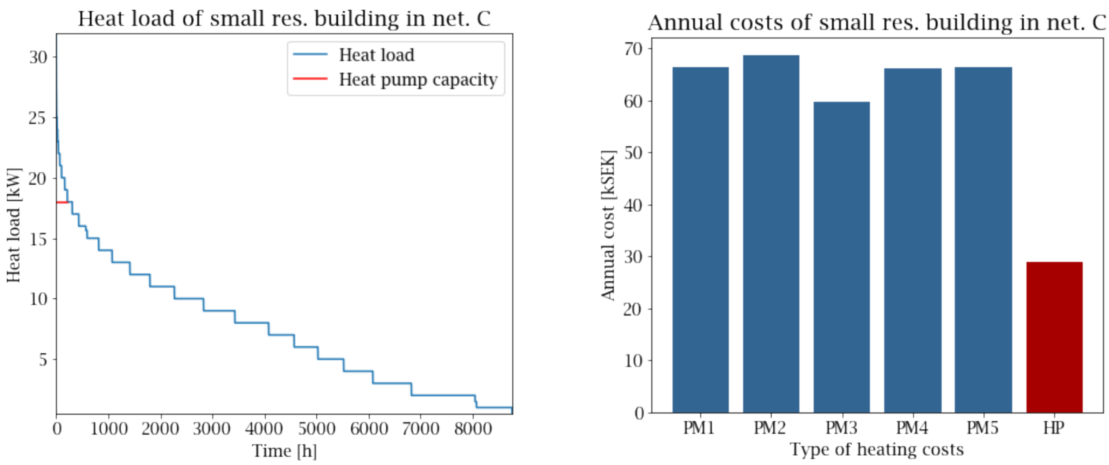
Figures 4.16a and b show these same results but for the small residential building in network B. As we can see, the needed HP capacity was 23 kW which would cover 98.2% of the total heat demand. It can again be seen how the running costs of the HP are lower than the cost that would be paid by having DH with either of the five price models. Table 4.7 shows that when taking into account the investment cost of the HP, the PBP would be 9.4 years, and the NP_a would be 3 kSEK/year. The reason for the decreased profit from the building in network A can be explained by the number of hours above the HP capacity.

Similar results can be seen in figures 4.17a and b, which show the results for the building in network C, which needed 18 kW of HP capacity which would cover 97.97% of the total heat demand over the year. The difference between the running costs of the HP and the cost of DH is significantly high in this building. Table 4.7 shows this even better as it shows that the PBP would be only 6.34 years and the NP_a would be 15.47 kSEK/year.



(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.16: *Heat load of a small residential building in network B along with the corresponding annual HP cost in comparison with the annual cost of the five price models*



(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

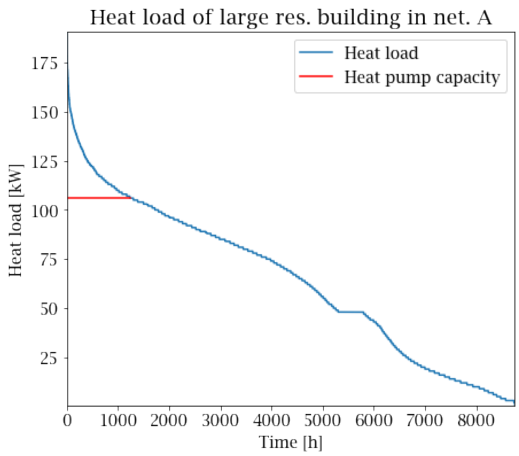
Figure 4.17: *Heat load of a small residential building in network C along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

Table 4.7: *Profitability calculation of an investment in a HP in a small residential building in the three networks when interest rate is 5% and lifetime of the HP is 15 years*

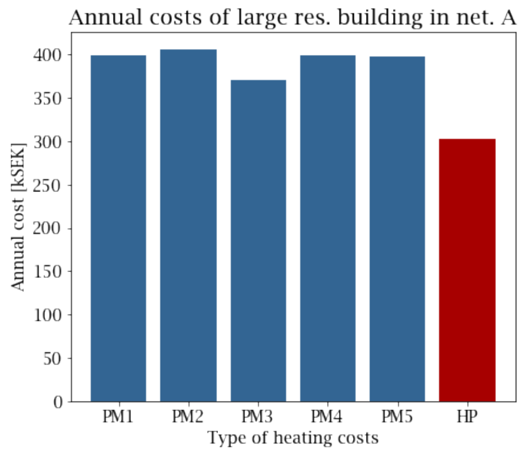
	Net. A	Net. B	Net. C
Annual DH cost [kSEK/yr]	70.6	86.7	68.7
HP capacity [kW]	17	23	18
HP running costs [kSEK/yr]	41.74	54.89	28.95
HP unit price [kSEK/kW]	14	13	13
Total IC HP [kSEK]	238	299	252
Annual. IC HP [kSEK/yr]	22.93	28.81	24.28
PBP [years]	8.25	9.40	6.34
NPa [kSEK/yr]	5.93	3.00	15.47

4.3.2 Large residential buildings

The heat load of the large residential building in network A and the running costs of the HP that would be needed to cover 55% of the maximum heat demand can be seen in figure 4.18a and b. 106 kW would be needed, covering 96.35% of the total heat demand over the year. By comparing the results from the small residential buildings, it can be seen how the running costs substantially increase, which can be explained by the size difference of the needed HP capacity. As shown in table 4.8, the PBP of this investment would be 13.3 years, and the NP_a would be -29.14 kSEK/year, which tells us that this it would not be profitable to invest in that HP, at least not if the interest rate would be 5%.



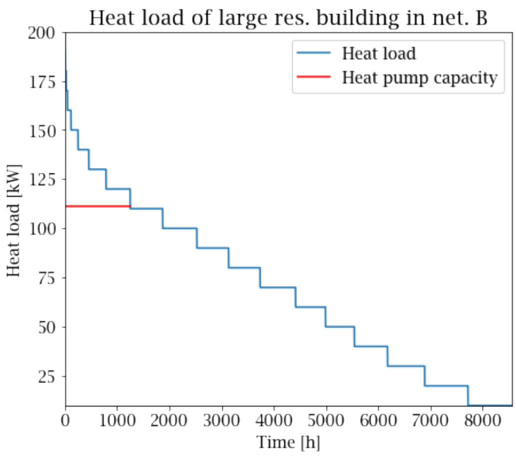
(a) *Heat load of building in 2019*



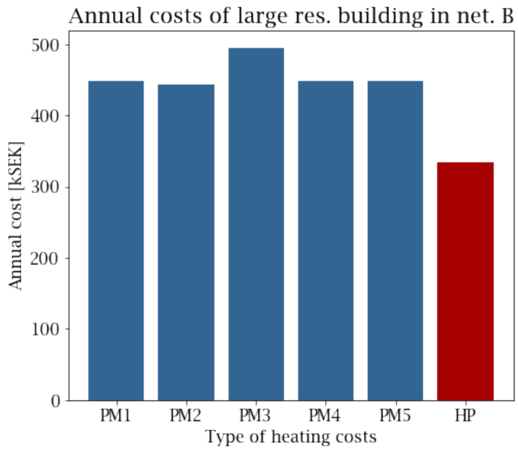
(b) *Annual running costs in 2019*

Figure 4.18: *Heat load of a large residential building in network A along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

Looking at figure 4.19 which shows the results for the large residential building in network B, it can be seen that almost the exact size of HP would be needed, or 111 kW to be exact. However, it can be seen from table 4.8 that the PBP would be 8.98 years, and the NP_a would be positive with a value of 21.74 kSEK/year. The fact that PM3 shows such a high cost for this building indicates that the return temperature from the building is high, which increases the cost of DH. Therefore, it can be concluded that if PM3 were used in that network, it would be profitable to invest in a HP. However, if one of the other four price models were used, the results would not necessarily indicate a good investment. Especially considering that the running costs of the HP in network B are higher than the ones in network A due to higher electricity prices being present in network B.



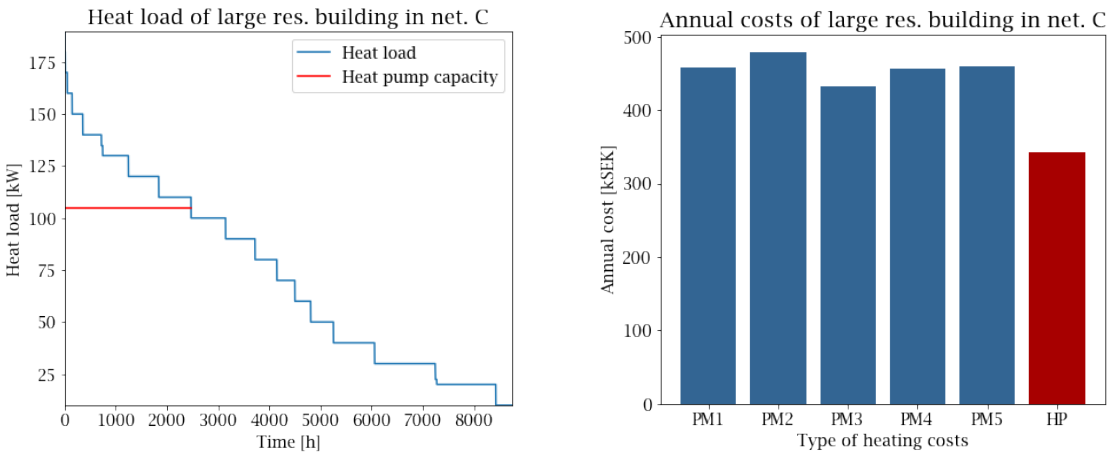
(a) *Heat load of building in 2019*



(b) *Annual running costs in 2019*

Figure 4.19: *Heat load of a large residential building in network B along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

Figure 4.20a and b shows the results for the building in network C. 105 kW HP would be needed, which would cover 91.07% of the total heat demand over the year. The reason for the lower coverage percentage compared to the other two networks can be explained by the amount of heat demand that is above the HP capacity limit. This can be seen by comparing the areas above the red HP capacity lines in figures 4.18a, 4.19a, and 4.20a.



(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.20: *Heat load of a large residential building in network C along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

Looking at table 4.8 it can be seen that with a 5% interest rate and a HP with 15 year lifetime, the investment would result in profit, or NP_a of 5.09 kSEK/year and PBP of 9.99 years. It is interesting to note that even though this building has almost the same HP capacity as the building in network A, it shows profit while the other does not. This is because the cost of DH is higher for the building in network C, making it more worth it to invest in a HP.

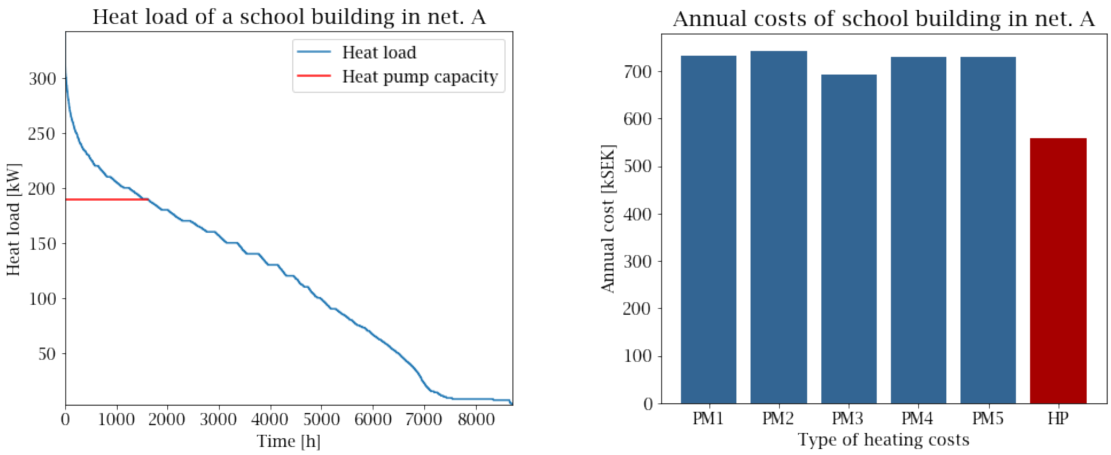
Table 4.8: *Profitability calculation of an investment in a HP in a large residential building in the three networks when interest rate is 5% and lifetime of the HP is 15 years*

	Net. A	Net. B	Net. C
Annual DH cost [kSEK/yr]	406	495	479
HP capacity [kW]	106	111	105
HP running costs [kSEK/yr]	302.38	334.24	342.4
HP unit price [kSEK/kW]	13	13	13
Total IC HP [kSEK]	1378	1443	1365
Annual. IC HP [kSEK/yr]	132.76	139.02	131.51
PBP [years]	13.3	8.98	9.99
NPa [kSEK/yr]	-29.14	21.74	5.09

4.3.3 School buildings

Looking at figure 4.21a, it can be seen that the needed HP capacity for the school building in network A was 189 kW, which would cover 95.05% of the total heat demand. Figure 4.21b shows that the annual running costs for the HP would be 559.11 kSEK/year, which is lower than the cost of DH, which either of the five price models would be around or over 700 kSEK/year. Table 4.9 shows the calculated

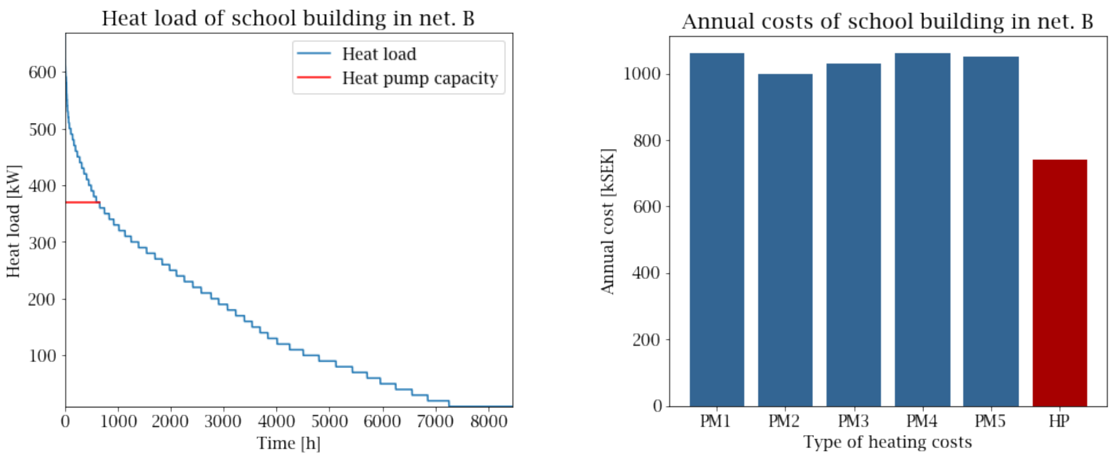
PBP and NP_a of the investment, which would be 13.36 years and -52.82 kSEK/year, respectively, which tells us that the investment would most likely not be worth it.



(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.21: *Heat load of a school building in network A along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

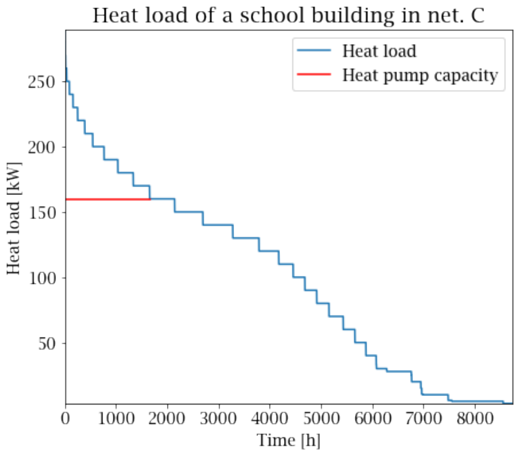
Figure 4.22a and b show the same results but for the school building in network C. The needed HP capacity would be pretty high, or 369 kW, and it would cover 96.3% of the total heat demand. As expected from this capacity size, the investment would not be profitable. The PBP would be 15.09 years which is higher than the lifetime of the HP, and the NP_a would be -144.16. These numbers are shown in table 4.9.



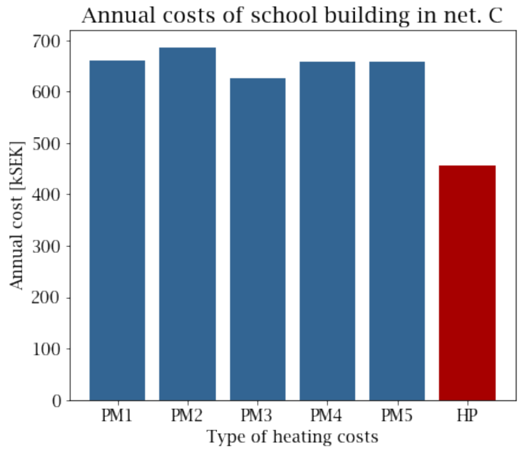
(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.22: *Heat load of a school building in network B along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

The school building in network C needed the lowest HP capacity, as can be seen in figure 4.23. The needed HP capacity was 160 kW which would cover 92.7% of the heat demand and result in running costs of 456.42 kSEK/year.



(a) *Heat load of building in 2019*



(b) *Annual running costs in 2019*

Figure 4.23: *Heat load of a school building in network C along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

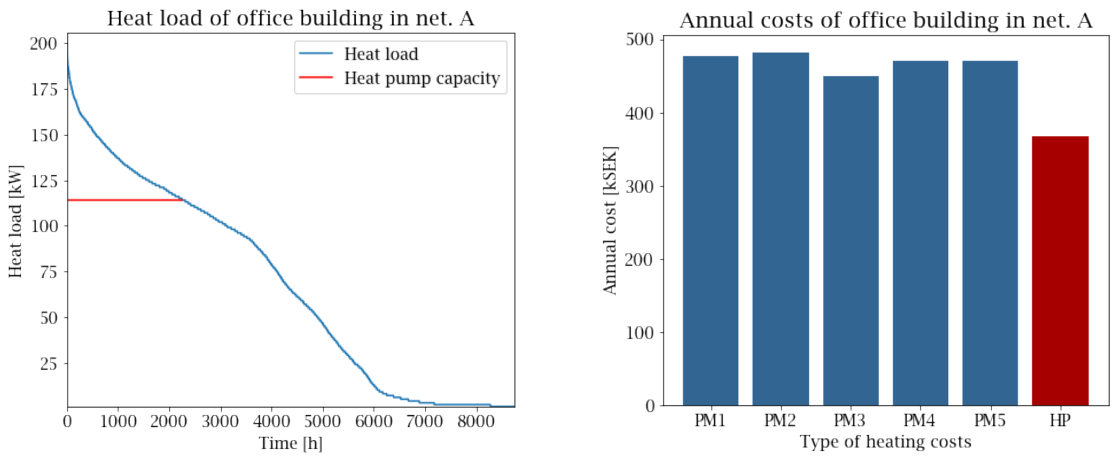
As table 4.9 shows, this building was the only one that would result in profit. The PBP would be 9.06 years and the NP_a 29.19 kSEK/year. This building had the lowest running costs due to being the one with the lowest needed HP capacity is the reason for the investment being profitable in this case.

Table 4.9: *Profitability calculation of an investment in a HP in a school building in the three networks when interest rate is 5% and lifetime of the HP is 15 years*

	Net. A	**Net. B**	**Net. C**
Annual DH cost [kSEK/yr]	743	1060	686
HP capacity [kW]	189	369	160
HP running costs [kSEK/yr]	559.11	742.01	456.42
HP unit price [kSEK/kW]	13	13	13
Total IC HP [kSEK]	2457	4797	2080
Annual. IC HP [kSEK/yr]	236.71	462.15	200.39
PBP [years]	13.36	15.09	9.06
NPa [kSEK/yr]	-52.82	-144.16	29.19

4.3.4 Office buildings

By looking at figure 4.24 it can be seen that size of the needed capacity of the office building in network A was 114 kW, whereas quite some hours would be needed above the capacity limit. For that reason, the running costs are pretty high compared to the size of the HP or 367.5 kSEK/year. The PBP of this investment would be 12.94 years and the NP_a -258.28 kSEk/year, so not profitable. These numbers can be seen in table 4.10.

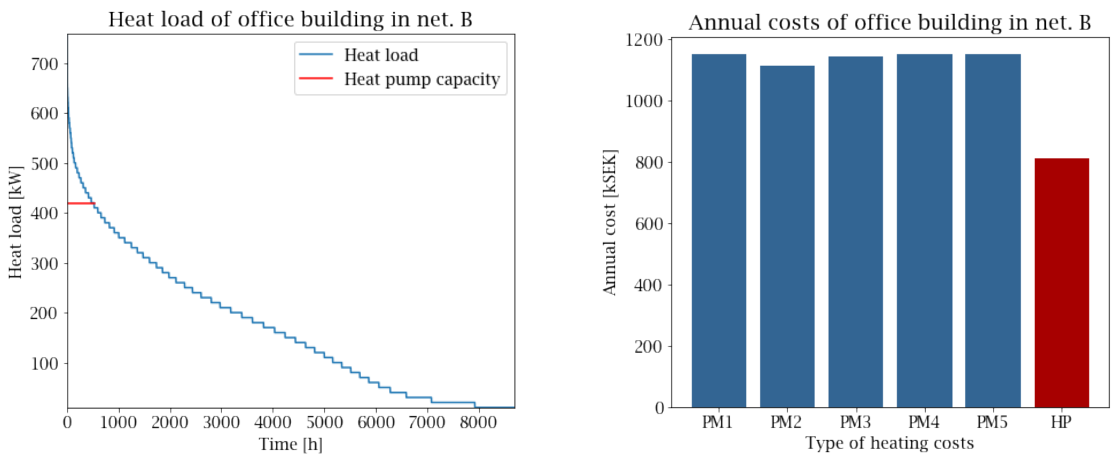


(a) *Heat load and HP capacity of the office building in 2019*

(b) *Annual running costs of the office building in 2019*

Figure 4.24: *Heat load of office building in network A along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

Network B had a very high peak load in their office building which gives the needed HP capacity of 419 kW, indicating that the investment will unlikely be profitable. This can be seen in figure 4.25 along with the calculated running costs, which were 809.5 kSEK/year. As expected, the PBP would be 16 years, which is higher than the HP lifetime, and the NP_a would be -184.38 kSEK/year, so it would be a very bad investment.

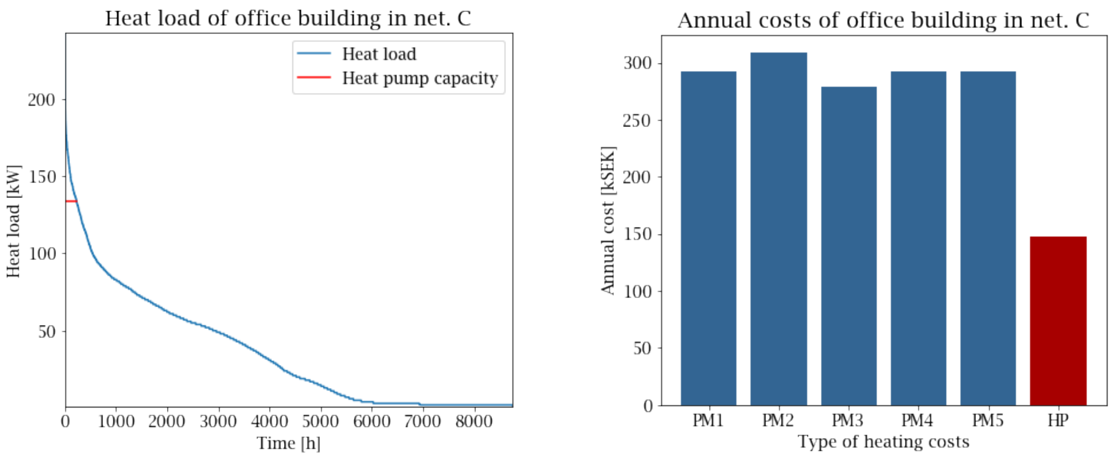


(a) *Heat load of building in 2019*

(b) *Annual running costs in 2019*

Figure 4.25: *Heat load of office building in network B along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

The office building in network C did not have as high demand as the one in network B. As figure 4.26 shows, the needed capacity would be 134 kW which would correspond to running costs of 147.87 kSEK/year.



(a) *Heat load of building in 2019*   **(b)** *Annual running costs in 2019*

Figure 4.26: *Heat load of office building in network C along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

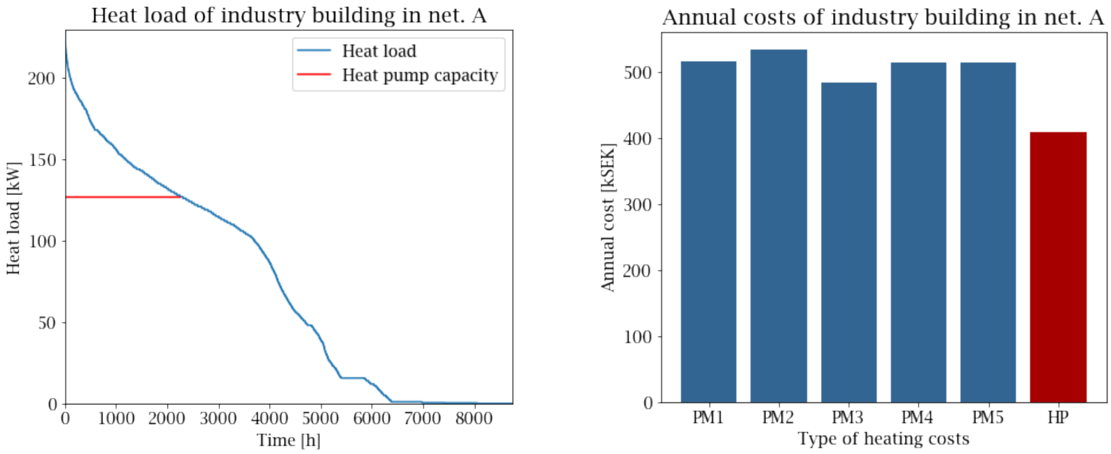
Table 4.10 shows that despite the running costs being half the ones if DH were used, it would still not be profitable. The PBP would be 10.91 years and the NP_a -6.7 kSEK/year. The HP capacity is relatively high, and the hours needed above the capacity limit are quite a few, or only 226 hours, to be exact. The HP covers 98.51% of the total heat demand. Therefore, the investment cost is relatively high compared to how little the demand is at that size of capacity, so for this specific building, it might be worth looking into covering less than 55% of the maximum load and lowering the investment cost.

Table 4.10: *Profitability calculation of an investment in a HP in an office building in the three networks when interest rate is 5% and lifetime of the HP is 15 years*

	Net. A	**Net. B**	**Net. C**
Annual DH cost [kSEK/yr]	482	1150	309
HP capacity [kW]	114	419	134
HP running costs [kSEK/yr]	367.5	809.6	147.87
HP unit price [kSEK/kW]	13	13	13
Total IC HP [kSEK]	1482	5447	1742
Annual. IC HP [kSEK/yr]	142.78	524.78	167.83
PBP [years]	12.94	16.00	10.81
NPa [kSEK/yr]	-28.28	-184.38	-6.70

4.3.5 Industry buildings

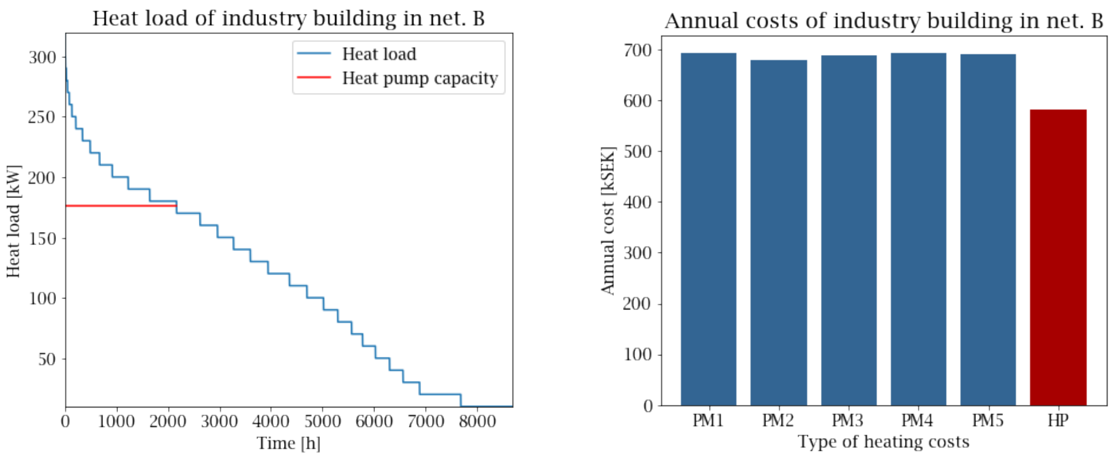
Figure 4.27 shows the heat demand over the year for the industrial building in network A along with the expected running costs. It can also be seen that the needed HP capacity is 127 kW. Table 4.11 shows that the calculated PBP for the investment was 13.17 years, and the NP_a was -33.73 kSEK/year, so not a profitable investment.



(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.27: *Heat load of industry building in network A along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

The industrial building in network B had a little higher demand. The HP capacity would need to be 176 kW, which corresponds to 581.57 kSEK/year. This can be seen in figure 4.28. As shown in table 4.11, the PBP for this investment would be 20.53 years, which is way higher than the lifetime of the HP, and the NP_a would be -109 kSEK/year. It can therefore be concluded that this investment would not be profitable. It is also worth noting that the running costs of the HP are not so much lower than the cost of the most expensive DH price model, so these results could be expected.

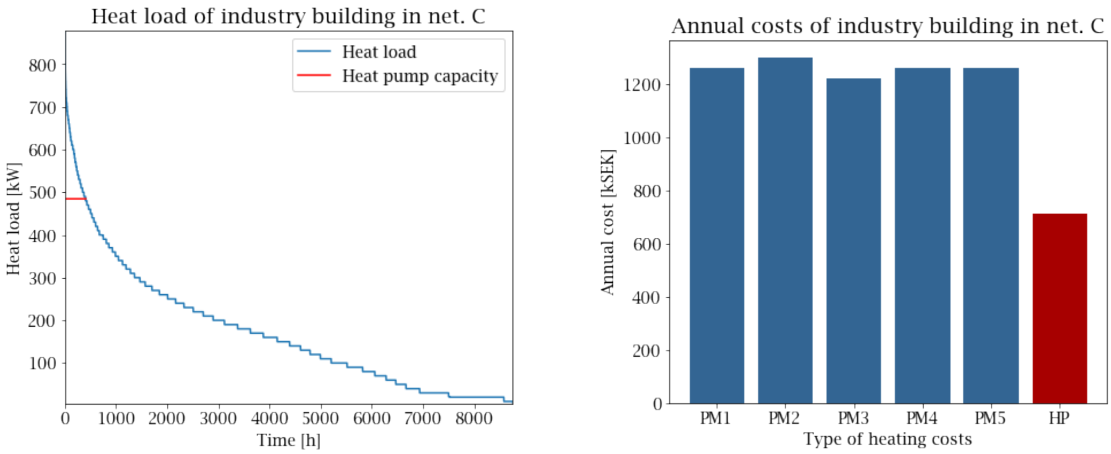


(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.28: *Heat load of industry building in network B along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

Looking at the industrial building in network C, shown in figure 4.29 it can be seen that the heat demand is very high, so the needed HP capacity would be 485 kW.

That would result in running costs of 714.41 kSEK/year, which is still relatively low compared to the cost of DH for the building.



(a) *Heat load of building in 2019* **(b)** *Annual running costs in 2019*

Figure 4.29: *Heat load of industry building in network C along with the corresponding annual HP cost in comparison with the annual cost of the five price models*

The expected PBP of this investment was calculated as 10.77 years and the NP_a as -21.85 kSEK/year and can be seen in table 4.11. One could have expected it to be worth it to go for this investment due to the cost of the DH price models being almost twice as high as the running costs of the HP, but due to the high investment cost, that is not the case.

Table 4.11: *Profitability calculation of an investment in a HP in an industry building in the three networks when interest rate is 5% and lifetime of the HP is 15 years*

	Net. A	**Net. B**	**Net. C**
Annual DH cost [kSEK/yr]	535	693	1300
HP capacity [kW]	127	176	485
HP running costs [kSEK/yr]	409.67	581.57	714.41
HP unit price [kSEK/kW]	13	13	13
Total IC HP [kSEK]	1651	2288	6305
Annual. IC HP [kSEK/yr]	159.06	220.43	607.44
PBP [years]	13.17	20.53	10.77
NPa [kSEK/yr]	-33.73	-109.00	-21.85

5
Conclusion

In this thesis, the performance of different price models and the competitiveness of heat pumps against district heating systems were evaluated. The aim was to see if different recommendations would be made for different networks as the networks can be very different from each other.

5.1 Price models

The results from the price model simulations showed how different cost components perform differently in different networks. Therefore, the conclusion is not one correct answer for everyone but somewhat different recommendations for different networks. An excellent example of this was PM3 which included the RT in the price model. Networks A and C, which both seem to have good system efficiency when it comes to having low return temperatures from the substations in the system, showed how it was not favourable for them to include it in their price model as the revenues would decrease. Network B showed promising results when including this component as it had worse return temperatures in its system. Many substations would be charged an extra fee for having high return temperatures.

Suppose the DH company wants to change their price model so that the variable costs match the actual production costs better. In that case, it is possible to set the price in a way so when increasing the number of seasons and having high and low demand times during the day without affecting the company's total annual revenues. PM1, PM4 and PM5 showed this well as they performed the same in all networks during all years. In addition, these price models showed relatively small customer revenue change for all the fifteen buildings which is a great advantage.

All the networks agreed on which price model was best during warm years, which was PM2, which could be expected since that price model does not size the power component based on last year's usage but based on power signature and hence, is constant throughout the years. That is a good quality if the DH company aims for fewer variations in the yearly revenues and more predictable revenues. The variations were on average 2.5-3% less than in the other price models, depending on networks. PM2 had the most apparent linear relation when plotting the degree days against the yearly revenues, highlighting how that price model is the most predictable one.

5.2 Heat pump comparison

The results of the HP comparison calculation showed that the higher the needed HP capacity was, the less likely it was to be a profitable investment due to the high investment cost of the HP. It could also be seen how some of the buildings had a maximum load that was much higher than the usual heat load of the building, which resulted in unnecessary large HP where the HP would very seldom be operating at max load. Therefore, it is essential to look at the heat load profile of the building and see how much heat energy would need to be delivered with direct electricity. If the area above the HP capacity is little, it could be worth it to invest in a smaller HP to decrease the investment cost.

However, from the sensitivity analysis performed, it could be seen how both the assumed interest rate and the lifetime of the heat pumps significantly impacted whether the investment was profitable. The higher the interest rate was and the lower the lifetime of the heat pump was, the higher the PBP was and the lower the NP_a was.

It is also important to note that the results are highly dependent on the electricity prices in 2019, as they were used when calculating the running costs of the HPs. If the electricity prices increased in the future, that would result in higher running costs for the HPs and, therefore, most likely be favourable for the DH companies. On the other hand, if electricity prices would go down, HPs would become more profitable and increase the competition with the DH companies.

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A
Sensitivity analysis

Sensitivity analysis was performed on the assumed interest rate and lifetime of the HPs and are presented in this chapter. All of them showed how as the interest rate increased and the lifetime of the HP decreased, the PBP increased and the NPa decreased. Figures for each building in each network are shown in the following sections. However, it is important to keep in mind that there are more factors that significantly influence the profitability of the buildings, such as the electricity prices over the year as the running costs are directly related to them. In addition, the heat load profiles of the buildings have big impact. If the hours above the HP capacity are low, the size of the HP might be overestimated, resulting in unnecessary high investment cost of the HPs.

Small residential buildings

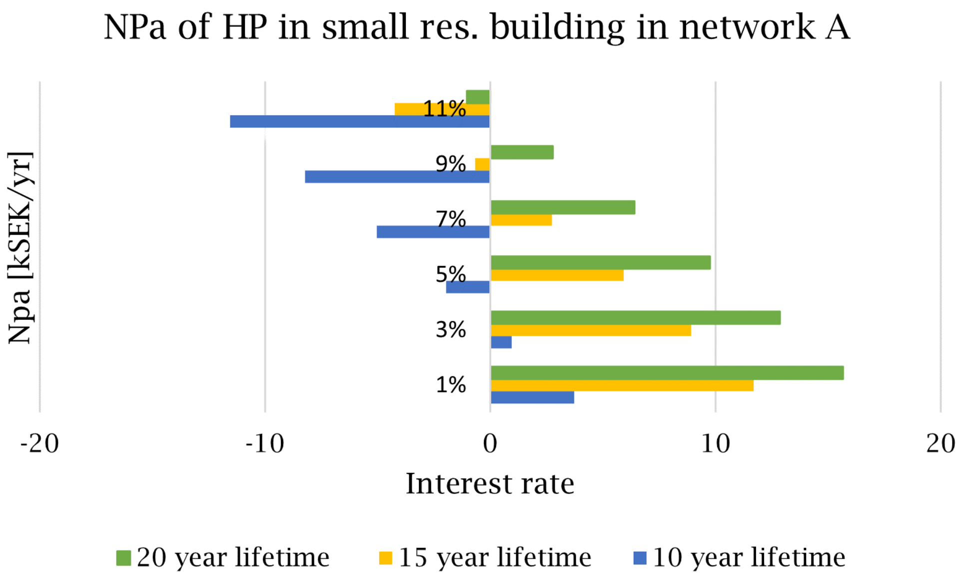

Figure A.1: *Annual net present value (NPa) of an investment in a HP in a small residential building in network A*

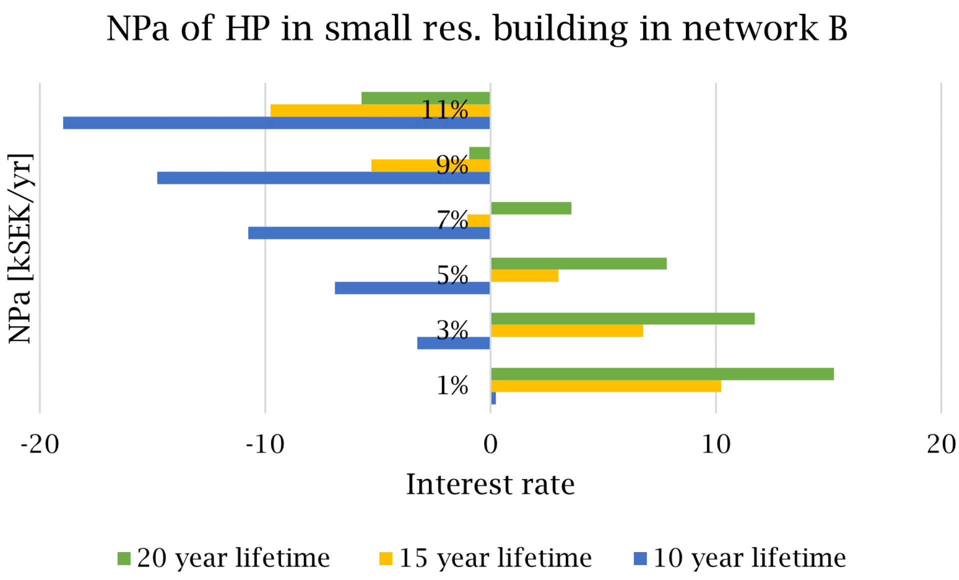

Figure A.2: *Annual net present value (NPa) of an investment in a HP in a small residential building in network B*

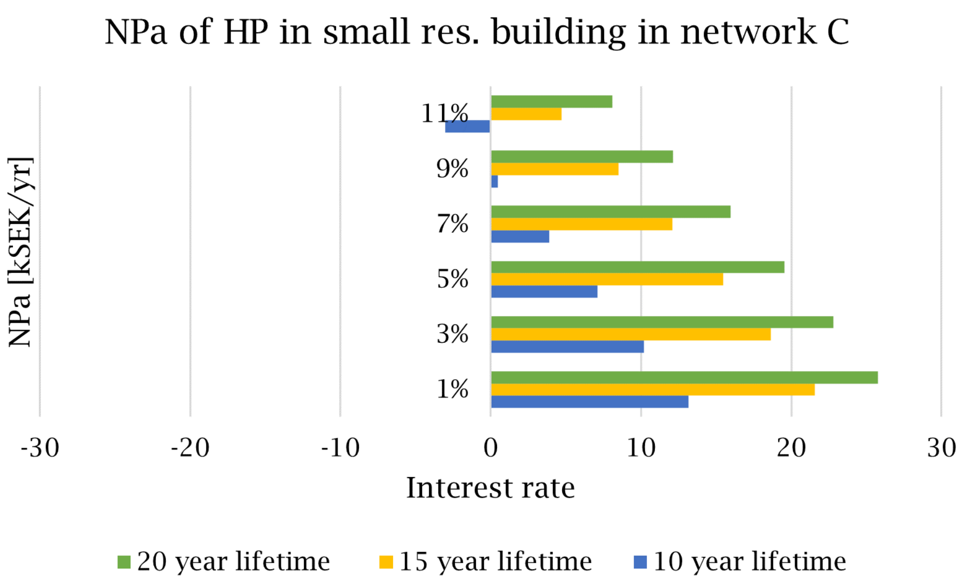

Figure A.3: *Annual net present value (NPa) of an investment in a HP in a small residential building in network C*

Large residential buildings

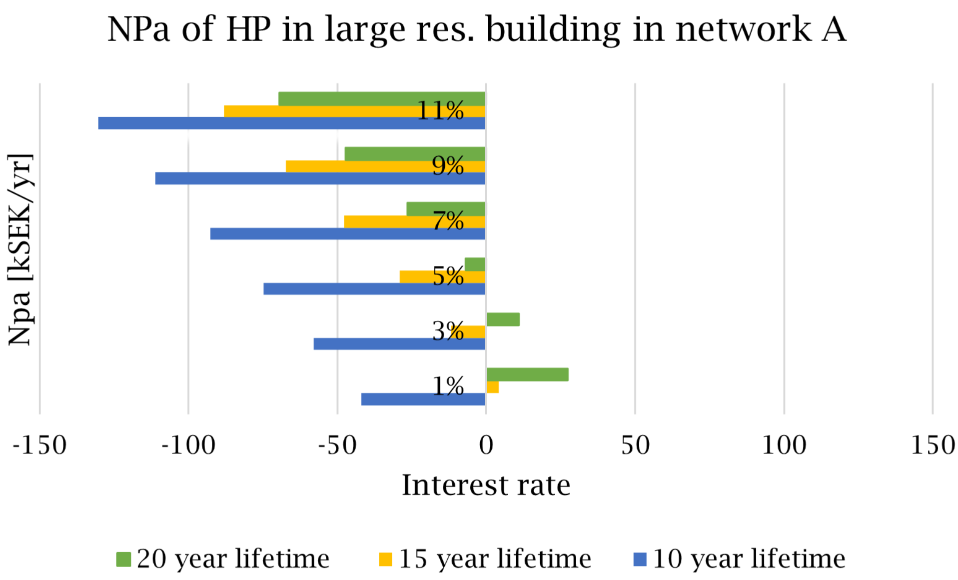

Figure A.4: *Annual net present value (NPa) of an investment in a HP in a large residential building in network A*

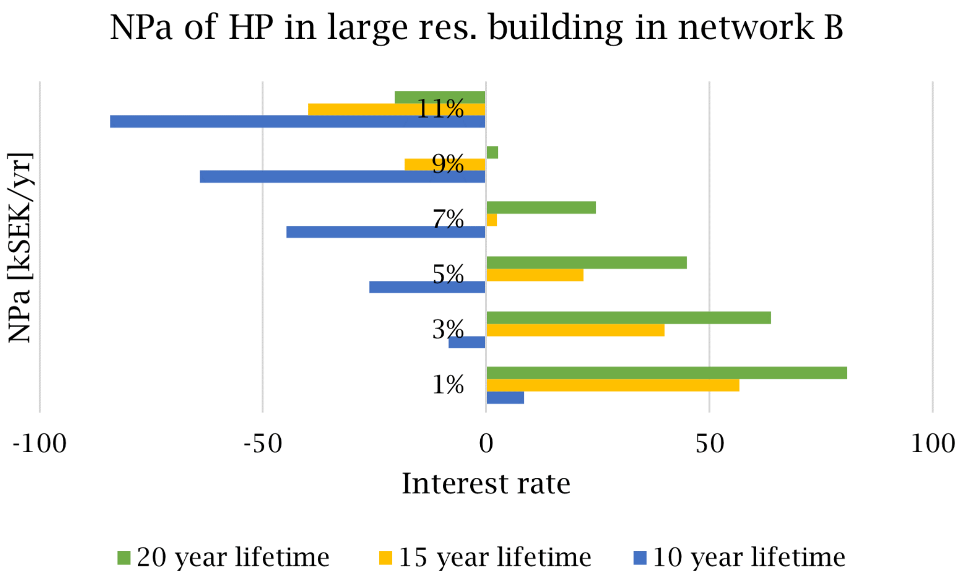

Figure A.5: *Annual net present value (NPa) of an investment in a HP in a large residential building in network B*

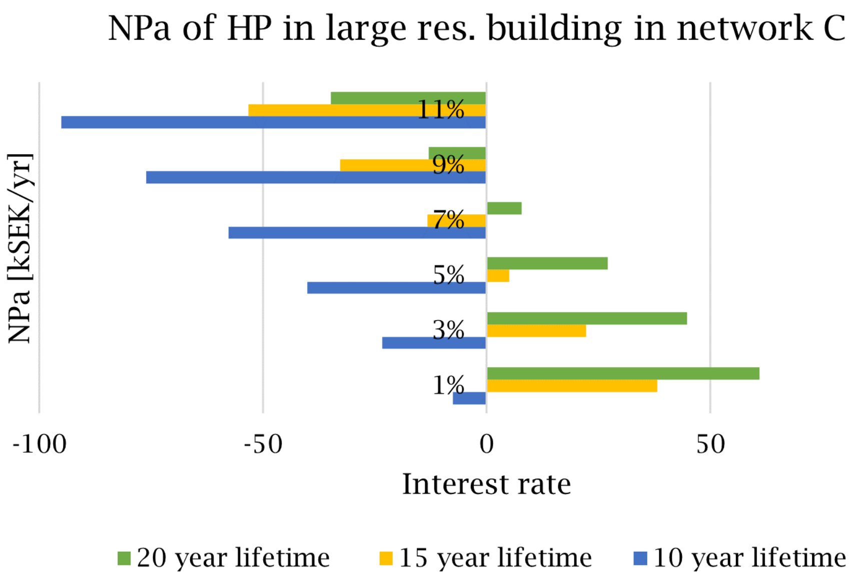

Figure A.6: *Annual net present value (NPa) of an investment in a HP in a small residential building in network C*

School buildings

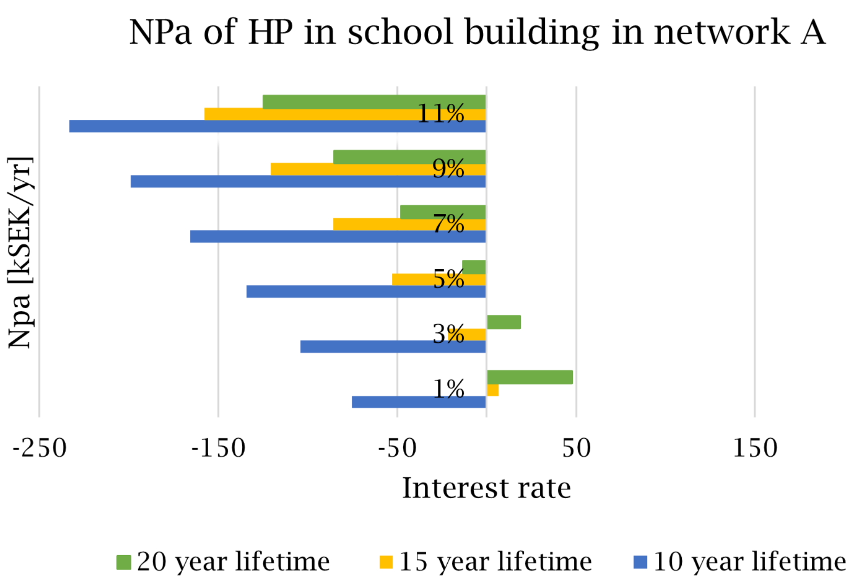

Figure A.7: *Annual net present value (NPa) of an investment in a HP in a school building in network A*

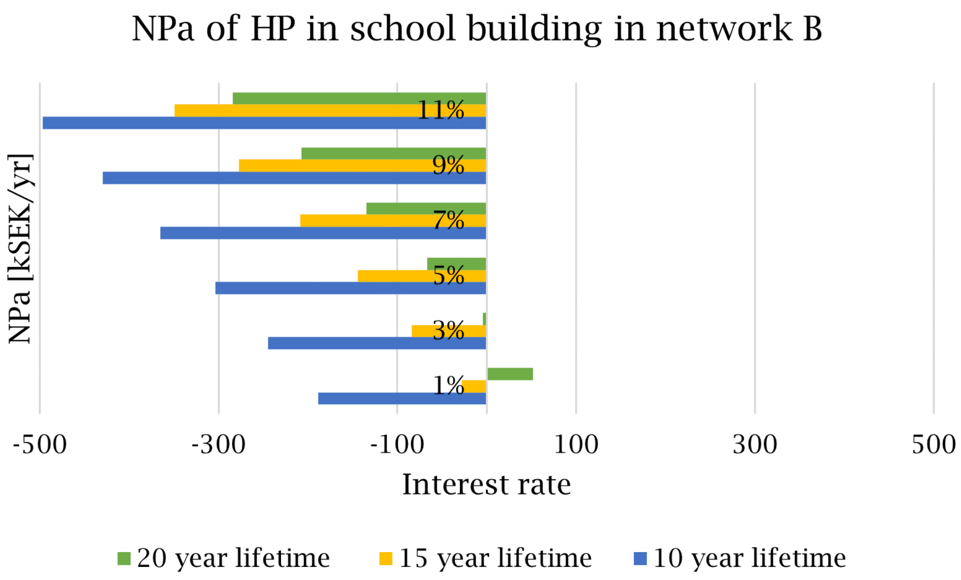

Figure A.8: *Annual net present value (NPa) of an investment in a HP in a school building in network B*

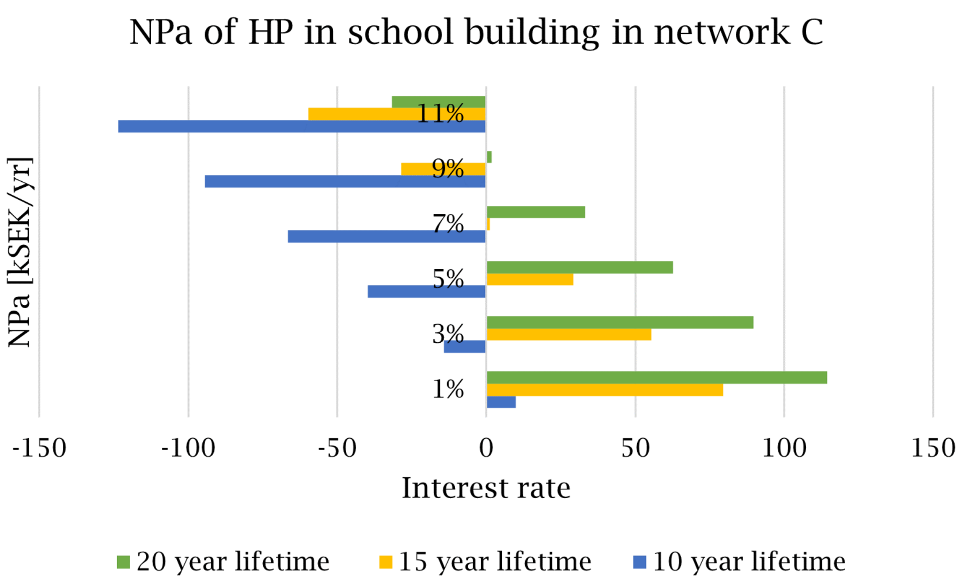

Figure A.9: *Annual net present value (NPa) of an investment in a HP in a school building in network C*

Office buildings

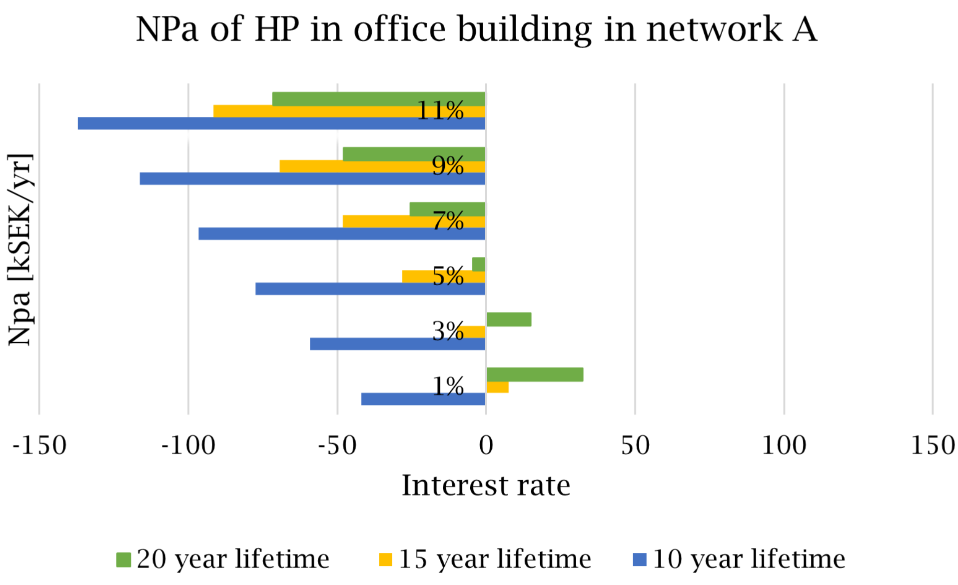

Figure A.10: *Annual net present value (NPa) of an investment in a HP in an office building in network A*

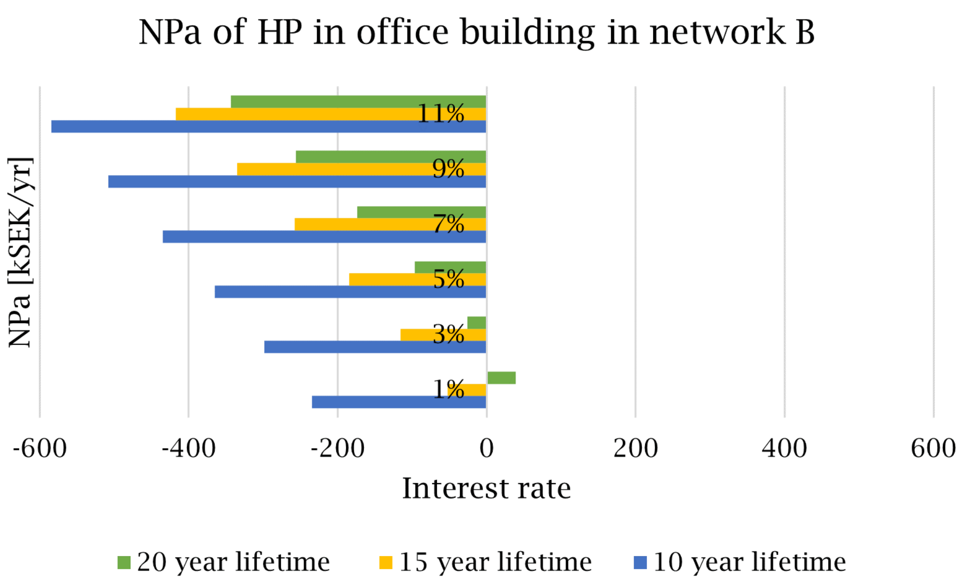

Figure A.11: *Annual net present value (NPa) of an investment in a HP in an office building in network B*

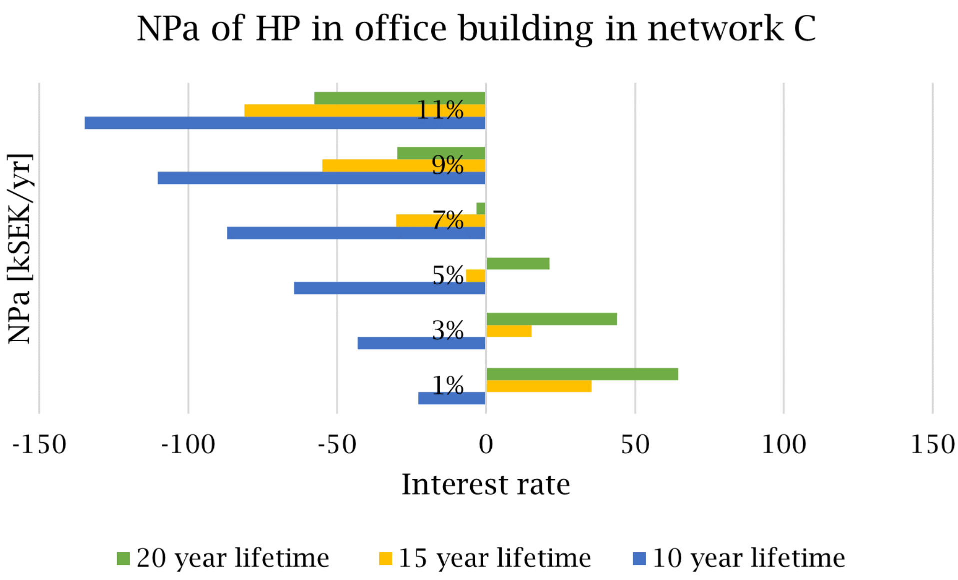

Figure A.12: *Annual net present value (NPa) of an investment in a HP in an office building in network C*

Industry buildings

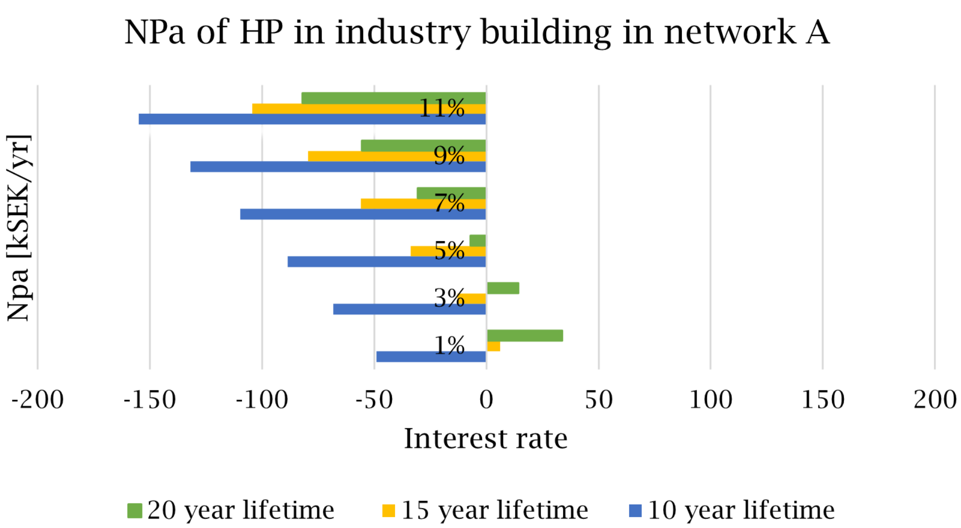

Figure A.13: *Annual net present value (NPa) of an investment in a HP in an industry building in network A*

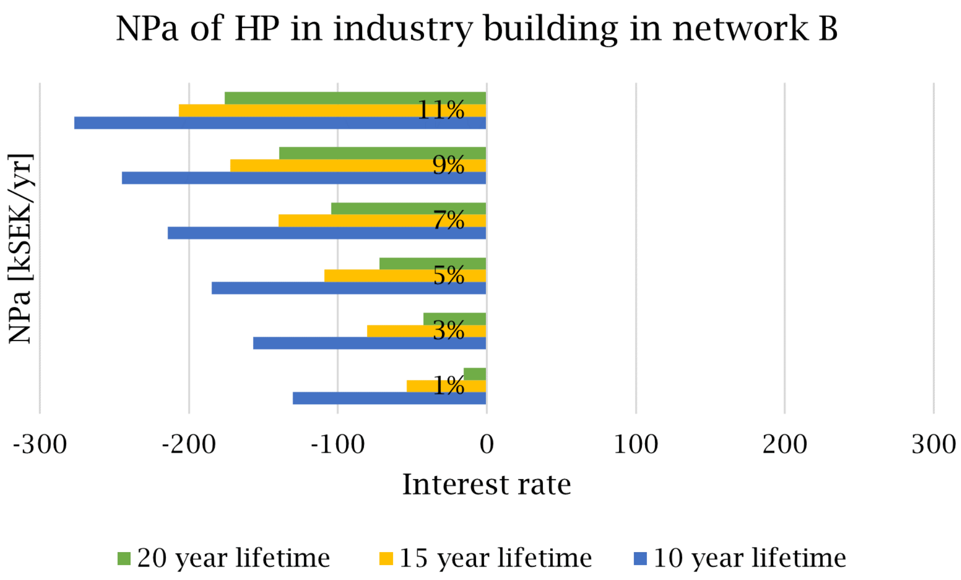

Figure A.14: *Annual net present value (NPa) of an investment in a HP in an industry building in network B*

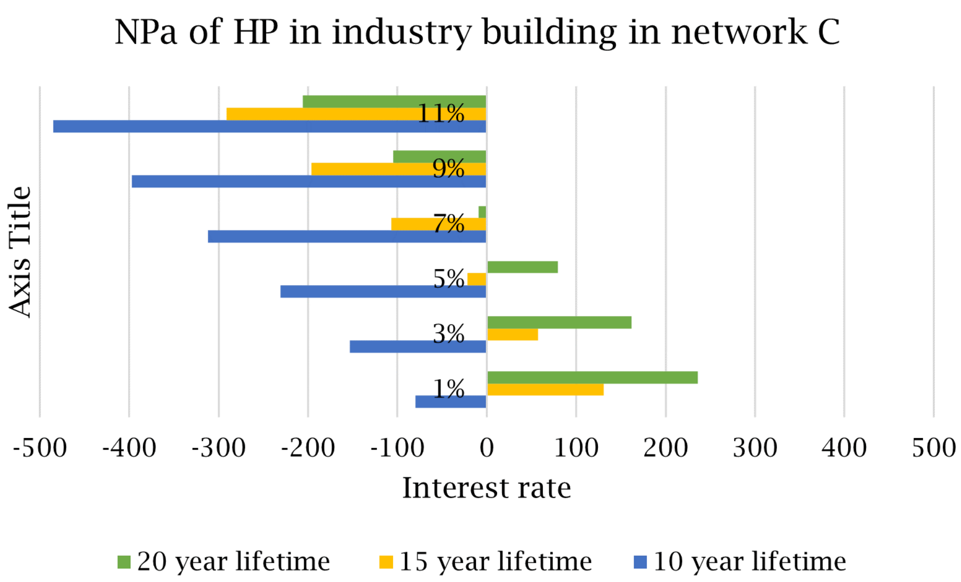

Figure A.15: *Annual net present value (NPa) of an investment in a HP in an industry building in network C*

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