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Sector coupling of the electricity and district heating system of Gothenburg

Integrating electric boilers in a multi-zone district heating model

Master's thesis in Sustainable Energy Systems

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Abstract

To lower emissions of green house gases, Göteborg Energi AB plans to retire their fossil-fueled heat generation. To replace this generation, one possibility can be to utilise the existing electricity grid via power to heat generation. This master's thesis investigates the possibility for electrical boliers (EB)s to support the district heating system (DHS) by evaluating economical viability, geographical placements and the role EBs can take in heat generation.

A techno-economical model of the DHS in Gothenburg was developed using linear programming in the software, General Algebraic Modeling System (GAMS). The modeled DHS of Gothenburg was divided into seven zones to account for bottlenecks within the DHS and the availability in the electricity system. Data was gathered from Göteborg Energi AB and Göteborg Energi Nät AB to depict the DHS during the period 2020-09-01 to 2021-04-30. The objective function was set to minimize the cost of heat generation while fulfilling the heat demand. With the possibility to invest in EBs, the model evaluated their competitiveness. Different cases and scenarios were studied, such as the implementation of possible future plants, reducing the energy tax on electricity, increasing fuel prices and the availability of electricity.

The results indicate that the operational cost are an important factor for the competitiveness of EBs which can be seen when looking at scenarios with lowered energy tax. For cases and scenarios that don't change the variable costs for the investigated period, the model only invests in EBs to fulfill the heat demand if no other option are available. When in use the EBs mostly contribute to heat generation during peak hours, yet, only when there is a low electricity price and sufficient grid capacity. Results show that EBs can be utilised as backup heat generation to a certain extent in all zones, but at different installed capacities.

With the conditions from the investigated period, EBs are not economically viable nor are they needed to fulfill the heat demand. Changing the conditions, the EB can become economically viable, and for these scenarios the EBs act as a combination of peak heat- and intermittent heat generation. The zones West, Frölunda and North are most of interest for installing EBs. The results show that with increased cost for bio-oil, an investment of about $30MW$ in North is interesting to further investigate. The model also showed a need for additional heating in West and Frölunda, but with less economical incentives for an investment in EBs due to cheaper heat generation in adjacent zones. The Frölunda zone was also more constrained when it came to available electricity.

Acknowledgements

First of we would like to thank our supervisors Åsa Toulja Jardeby at Göteborg Energi AB and Rasmus Erlandsson at the Division of Energy Technology for providing guidance troughout the project and helping us understand the district heating system of Gothenburg. Without their help, this thesis would not have been possible. We would also like to thank all personnel at Göteborg Energi AB that has provided us with both insight and data to be able to build our model and complete the project. Finally, we would like to thank Mikael Odenberger at the Division of Energy Technology for acting as examiner for this thesis and for pushing us to provide relevant results.

Tim Haagensen Thornström & Viktor Larsson, Gothenburg, Feb 2022

Contents

List of Abbreviations

CHP combined heat and power.
COP coefficient of performance.

DHS district heating system.

EB electric boiler.

FLH full load hours.

HOB heat only boiler.
HP heat pump.

SoC state of charge.

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1 Introduction

Due to emissions of green house gases during the last centuries, the global mean surface temperature had in 2017, increased by about 1.0 degrees Celsius compared to pre-industrial levels [1]. To limit the impact on the climate, countries around the world have begun to reduce their use of fossil fuel and instead turned to renewable and sustainable energy sources.

To handle abnormal peak load as well as the seasonal temperature changes in Nordic countries, fossil fueled back up plants are used in the district heating system (DHS). Even if they are run seldom, the goal for Göteborg Energi AB is to eliminate the need for fossil fueled back-up heat generation.

Together with the elimination of fossil power plants, Gothenburg is expected to increase in population to around 700 000 by 2035 [2] and that heat and electricity demand may increase. Today, the DHS in Gothenburg supplies heat to around 90% of the apartment buildings as well as 12 000 houses, industries, offices and other buildings [3]. According to Göteborg Energi AB there is currently sufficient grid capacity to provide electricity and heat to the city with some room for expansion. Yet, with continued growth of population this extra room will be limited and an expansion of both grids will be necessary for the continued urbanisation [4].

Instead of expanding the electricity grid to counter the increase in heat demand via power to heat plants, it should be possible to utilize the available grid capacity more efficiently. Investing in these power to heat solutions may result in economic gains, as well as providing flexibility to the DHS and the electricity grid. This led to the investigation of the combined electricity and DHS inside Gotheburg as well as how and when electric boiler (EB) can be used inside Gothenburg to complement the DHS.

1.1 Aim and research questions

This master's thesis investigates how EBs can be utilized in Gothenburg to complement the district heating system (DHS), using existing electricity grid capacity. This was done by developing a multi-zone model of Gothenburg that depicted availability as well as constraints of both electricity and heat. The model took into account when there is sufficient availability of electricity to operate EBs as well as economic aspects and geographical location within the city. The work aims to answer the following questions:

- Under what conditions are electric boilers economically viable in the Gothenburg DHS?
- Where in Gothenburg could EBs be placed considering the electric grid and district heating limitations? How does the placement complement the DHS and affect the running order of heat generation units?
- When is it suitable to generate heat using EBs in Gothenburg considering heat demand and availability in the local electric grid?
- Can EBs be used as a backup heat generation using existing electricity installations?

2 Method

This master's thesis include a development of a techno-economic model depicting the DHS of Gothenburg, with current heat generation facilities and potential future installations. The DHS of Gothenburg is in the model represented by seven zones to account for bottlenecks within the DHS but also to account for the availability in the electricity system. This allows the model to evaluate where in the city there is available electricity and if there is a demand for heat in that area.

Provided with the possibility to invest in EBs the model minimizes the total cost for heat generation in the DHS while meeting the heat demand. The model is implemented in GAMS.[5]

2.1 Model equations

The equations used in the model are presented in the following section. The parameters t, z and p are hours, zones and heat generation plants in the specified zone and describes what each variable depends on.

The objective function in Equation 2.1, summarises all costs i.e., the variable running costs as well as the equivalent annual cost investing in new boilers.

$$T_{cost} = \sum_{t,z,p} G(t,z,p) * V_{cost}(p) \ + \ \sum_{p} EAC_{cost}(p) * CAP(p) \tag{2.1}$$

where $T_{cost}[SEK]$ is the total cost for the model to fulfill all constraints during the period. $G(t,z,p)[MWh/h]$ is the heat generation. $V_{cost}[SEK/MWh_{heat}]$ and $EAC_{cost}(p)[SEK/MW]$ are the variable costs for running each plant as well as the equivalent annual cost per MW installed capacity for specific plants. $CAP(p)[MW]$ is the installed capacity of new heat generation.

The variable costs are given by Equation 2.2.

$$V_{cost}(p) = \frac{F_{cost}(p)}{\eta(p)} + O\&M_{cost}(p) \tag{2.2}$$

Where $F_{cost}[SEK/MWh_{fuel}]$ is the cost per MWh fuel, η is the thermal efficiency $[MWh_{heat}/MWh_{fuel}]$ and $O\&M_{cost}[SEK/MWh_{heat}]$ is the operations and maintenance cost per unit of heat generation.

The equivalent annual cost was calculated using Equation 2.3.

$$EAC_{cost}(p) = CAP(p) * \frac{IC(p) * r}{1 - (1 + r)^{-n(p)}} \tag{2.3}$$

Where $CAP(p)$ $[MW]$ is the rated capacity of the installation, which for both HOBs and CHPs is given for the heat generation capacity. $IC(p)$ $[SEK/MW]$ is the investment cost, r is the discount rate and $n(p)$ $[years]$ is the technical lifetime for the specified plant.

The heat balance in each region is given by Equation 2.4.

$$Demand(t, z) = \sum_{p} G(t, z, p) * T_{loss}(t) + I(t, z) * I_{loss} - E(t, z) - S_{C/DC}(t, z) - C(t, z) \tag{2.4}$$

Where $I(t, z)$ is the import and $E(t, z)$ is the export of heat to the different zones. $S_{C/DC}(t, z)$ represents the charge or discharge of heat in either the accumulator tank or the grid. The cooling $C(t, z)$ was introduced as a slack variable to evaluate the eventual overproduction of heat. No cost or constraints were put on this variable. $T_{loss}(t)$ is the same for all plants and set to represent the local zone transmission loss. I_{loss} is the export/import loss between zones.

The relation between electricity and heat generation in CHP facilities is given by Equation 2.5.

$$G_{el}(t, chp \in p) = G(t, chp \in p) * \alpha(chp \in p) \tag{2.5}$$

Where $G_{el}(t, chp \in p)$ is the electricity produced depending on the generation of heat $G(t, chp \in p)$ and the current power to heat ratio $\alpha(chp \in p)$. Any electricity production in CHP is subjected to credit in the objective function, corresponding to an assumed time-dependent electricity market spot price. This represent the production and selling of electricity. The cost reduction calculations can be seen in equation 2.6.

$$CR(t, chp \in p) = G_{el}(t, chp \in p) * El_{spot\ price}(t) \tag{2.6}$$

The fuel cost for HPs and EBs was set to an hourly assumed spot price. This causes the running cost for all of these plants to vary and the merit order to change with it. By using the spot price the model can evaluate the cost competitiveness of the EBs.

The role of the EBs was also evaluated by limiting the electricity usage for the EBs in each zone. A vector containing hourly available electricity for each zone, limited the EBs to use no more electricity than what was available during the investigated period. This limitation can be seen in Equation 2.7.

$$\sum_{p} \left(\frac{G(t, z, EB \in p)}{\eta}\right) \leq El_{available}(t, z) \tag{2.7}$$

Where $G(t, z, EB \in p)$ $[MWh/h]$ is the heat generated by the EBs in a specified zone and $El_{available}(t, z)$ is the hourly available electricity usable by the EBs. The

COP for HPs were used in the same way as efficiency in Equation 2.2.

Due to regulations for some of the plants, running constraints was implemented in the model to be able to limit the number of full load hours for the heat generation units. The constraint is presented in equation 2.8.

$$\sum_t G(t,z,p) \leq FLH(p) * Cap(p) \tag{2.8}$$

Where $FLH(p)$ is the assumed full load hours for respective plant.

Together with the generation, a zone can supply the demands by importing or exporting from/to adjacent zones. In the demand balance, import is set to replicate the delay in transferring heat troughout the DHS. This delay is represented by exporting in hour t, but receiving zone won't be able to utilise that heat for the demand balance until hour $t+1$.

To represent the losses throughout the DHS the I_{loss} was implemented as a loss factor when exporting heat between zones. The value is set between 0 and 1 depending on the losses in the DHS being implemented. Even though the model has perfect foresight and can compensate for this delay, it can affect the usage of electric boilers. This is due to the varying electricity prices and the ability to store heat.

The model includes a limitation on the transfer capacity of heat between regions according to Equation 2.10.

$$E(t,z) \leq E_{maxcap}(z) \tag{2.9}$$

Where $E_{maxcap}(z)$ is the maximum transferring capacity between two different and connected zones.

The heat storage's for both accumulation tank and grid storage were modeled in the same way. The heat storage state of charge (SoC) (storage capacity) was limited by Equation 2.10.

$$S_{SoC}(t,z) \leq S_{max\ cap} \tag{2.10}$$

Where S_{SoC} $[MWh]$ is the current SoC and $S_{max\ cap}$ $[MWh]$ is the maximum capacity.

The storage was also limited in maximum charging and discharging capacity each hour. This can be seen in equation 2.11.

$$S_{max\ out}(z) \leq S_{C/DC}(t,z) \leq S_{max\ in}(z) \tag{2.11}$$

$S_{C/DC}[MWh/h]$ is the charge and discharge rate of heat to or from the tank where $S_{max\ out}(z)$ has a negative value and $S_{max\ in}(z)$ is positive.

Taking both the maximum SoC and the charge and discharge rate into account, the hourly SoC was be set by equation 2.12.

$$S_{SoC}(t,z) = S_{SoC}(t-1,z) * SoC_{loss} + S_{C/DC}(t,z) \tag{2.12}$$

Where the current SoC at hour t was calculated by taking the SoC from previous hour and adding the charging or subtracting discharge of the accumulation tank from the current hour t. SoC_{loss} is a loss term that was included to account for heat loss over time.

2.2 The district heating system of Gothenburg

The modeled period corresponds to and make use of statistics from 2020-09-01 to 2021-04-30. Parameters used as input to the model was given by Göteborg Energi AB if not specified otherwise.

In the model, the DHS of Gothenburg was divided into seven zones, including Mölndal, due to their closely interlinked DHSs. The zones can be seen in Figure 2.1.

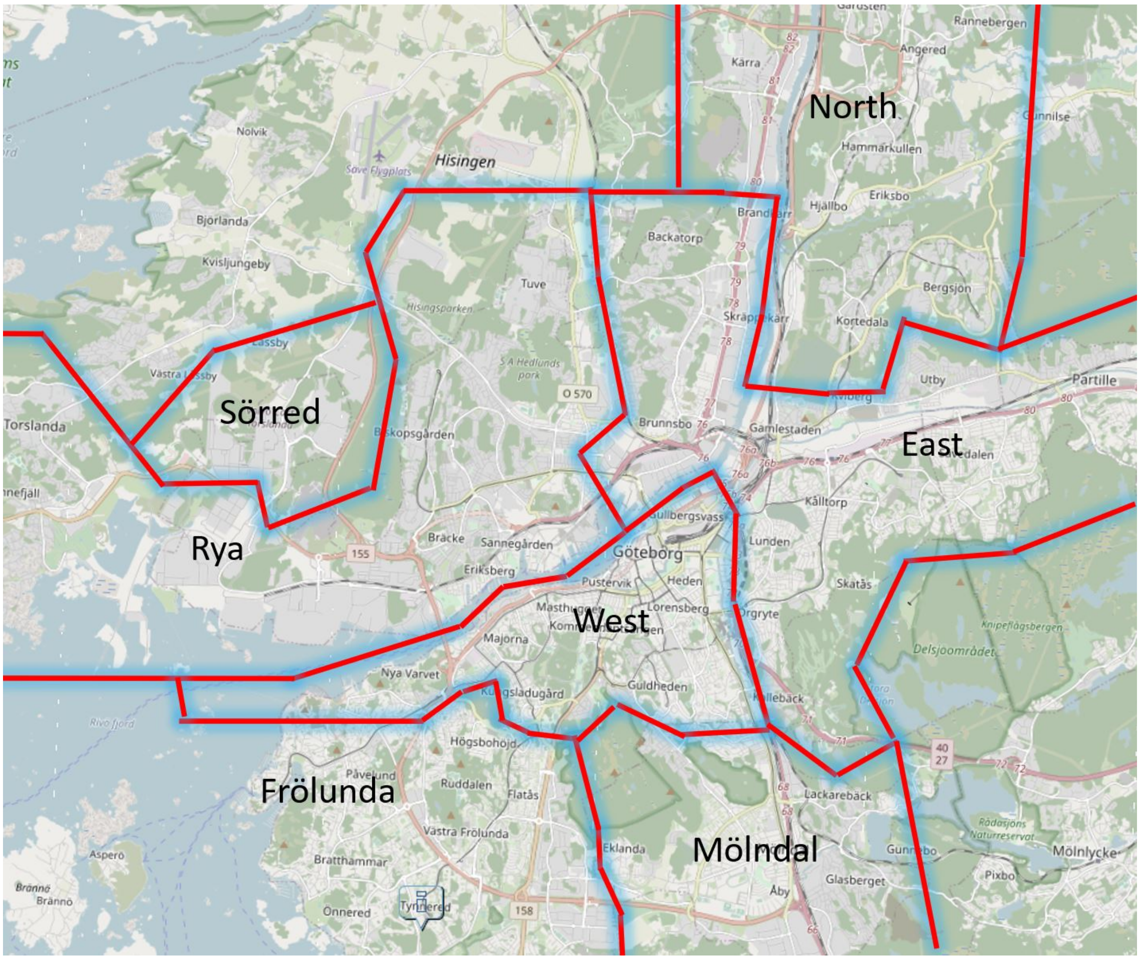

Figure 2.1: Zoning of the Gothenburg DHS

Each zone was set to supply a share of the total demand and the heat generation units were allocated to their respective geographic zone.

The total heat demand of Gothenburg was assumed to consists of a heating demand dependent on the outside temperature and behavioral part following the time of day. Data for the outdoor temperature-dependant part is presented in Table 2.1.

T_{out} $[°C]$	F_{load} $[-]$	$Total\ Demand\ [MW]$
-20	1.00	1768
-16	0.91	1606
-15	0.88	1556
-10	0.75	1326
-5	0.63	1113
0	0.51	901
6	0.34	601
8	0.28	495
10	0.21	371
15	0.09	159
20	0.09	159
30	0.09	159

Table 2.1: Outdoor temperature with respective load factor and total DHS demand

The demand for each temperature was calculated from the load factor, F_{load} and the demand at $-16°C$, being 1606 MW. By linearization of the load factor and outdoor temperature between $-20°C$ and $15°C$, Equation 2.13 was created.

$$Demand_{temp}(t) = \begin{cases} -46,267 + 864,94 * T(t)(°C) & \text{if } -20 \leq T(t) < 15 \\ 159,1 & \text{if } T(t) \geq 15 \end{cases} \tag{2.13}$$

For the temperature T(t) a rolling average of two hours before and two hours after was used.

The demand values in Table 2.1 are derived from the maximum daily load which occurs on a weekday at 17:00. The changes in heat load induced by human behaviour are modeled as a reduction from the maximum daily load, the diurnal pattern is shown in Figure 2.2.

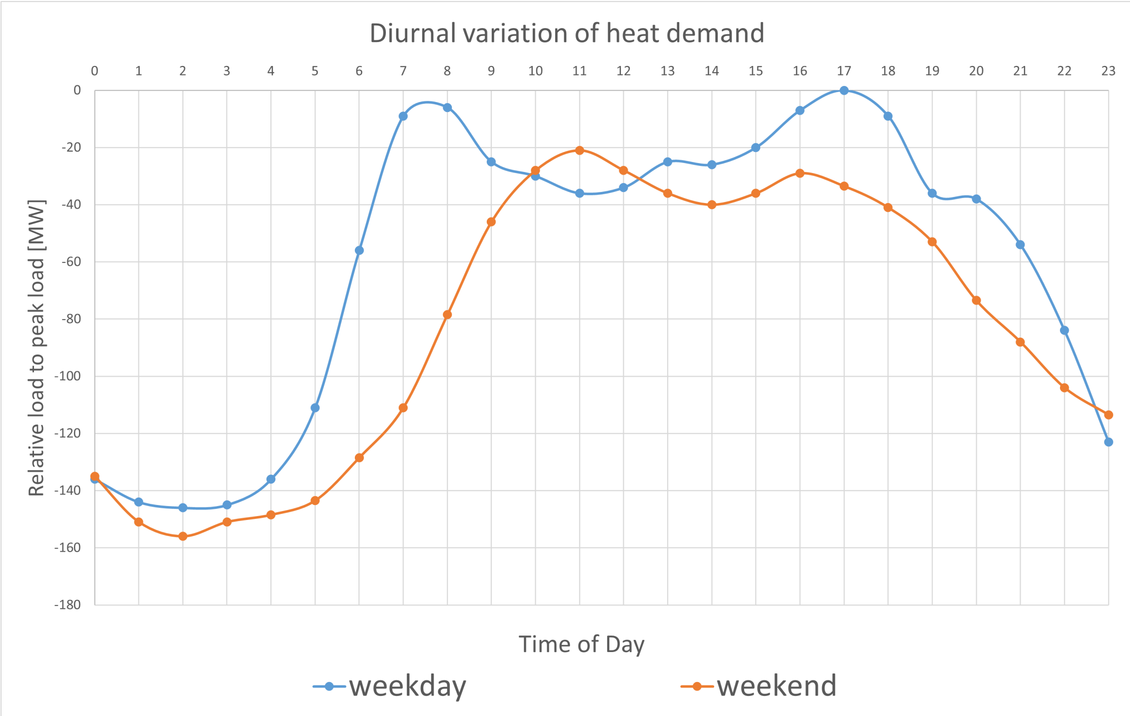

Figure 2.2: Diurnal heat demand variations as given by Göteborg Energi. The X-axis show time of day and the Y-axis gives the time dependent demand deviation from the temperature driven demand component.

The total demand was calculated by Equation 2.14.

$$Total\ demand\ (t) = Demand_{temp}(t) + diurnal\ variation\ (t) \tag{2.14}$$

The total demand (t) were divided to the zones according to the shares from the maximum daily load at $-16°C$, presented in Table A.1 in the Appendix.

The data for heat generation plants are presented in Table A.2 to A.8 in Appendix as well the cost of each fuel in Table A.9 [6]. Each of the excess heat sources was added as plants and their heat output limited by the hourly generation data during the investigated period.

Values of available electric grid capacity received from Göteborg Energi Nät AB was implemented in Equation 2.7 and are presented in Figures A.2-A.5 in the Appendix. The electricity availability in Rya is assumed to be shared with West.

Figure A.1 in the Appendix represents the spot price for electricity and was used for all cases and scenarios. The EBs and HPs are also affected by the energy tax of

$363[sek/MWh_{el}]$ which was added as a running cost. Other taxes and green electricity certificates were disregarded.

To be able to detect where and if the model fails to meet the demand, an imaginary high-cost heat generation "Gold boiler" unit was added to each zone. This allowed the model always to be solved, but with the significantly larger running cost it could be detected where the demand balance could not be met.

The DHS transmission values used for the model are presented in Table A.10 in Appendix and represent the maximum transmission capacity between the zones. Via discussion with Göteborg Energi AB it was concluded that the transmission capacity from West to Frölunda was highly dependent on the amount of heat imported from Mölndal. To replicate this phenomenon, the maximum import to Frölunda was set as the capacity from West. This meant that Frölunda could receive heat from Mölndal and West at all hours, but maximum to a total of the capacity of West to Frölunda. A small fee of $10SEK/MWh$ was added for each MWh of heat that was transferred between zones to constrain the model from "storing heat" by moving it back and forth between zones.

The heat storage accumulation tank in Rya was set to 1 000 MWh of total storage size and a charge/discharge rate of 150 MW. According to Göteborg Energi AB the grid of the Gothenburg DHS can buffer approximately 50MWh of heat per degree centigrade of increase in forward temperature. The forward temperature can be regulated between around 90 and 115°C, which is done to store heat and provide enough heat to the end line consumers. The maximum heat storage capacity of the network was assumed to be 50% of the temperature variation, and $A_{max\ cap\ network}$ was calculated by Equation 2.15

$$A_{max\ cap\ network} = 50 * (115 - 90) * 0.5 \tag{2.15}$$

The heat storage capacity for the respective zone was assumed to be proportional to the maximum heat demand in each zone. The charge and discharge rate of the accumulation in the grid was based on the same proportions as the accumulation tank, 15 % of the heat storage capacity. The heat storage sizes and their respective charge and discharge rates for each zone are presented in Table A.11 in the Appendix. The value for SOC_{loss} for the accumulation tank was set to 0.1% loss per hour and for heat stored in the grid it was set to 1% per hour.

The losses in the model is based on the losses for the Gothenburg DHS from January to April and September to December during 2018 and 2019. The export/import loss between zones, I_{loss}, was set to 5%. $T_{loss}(t)$ varies monthly according to Figure 2.3.

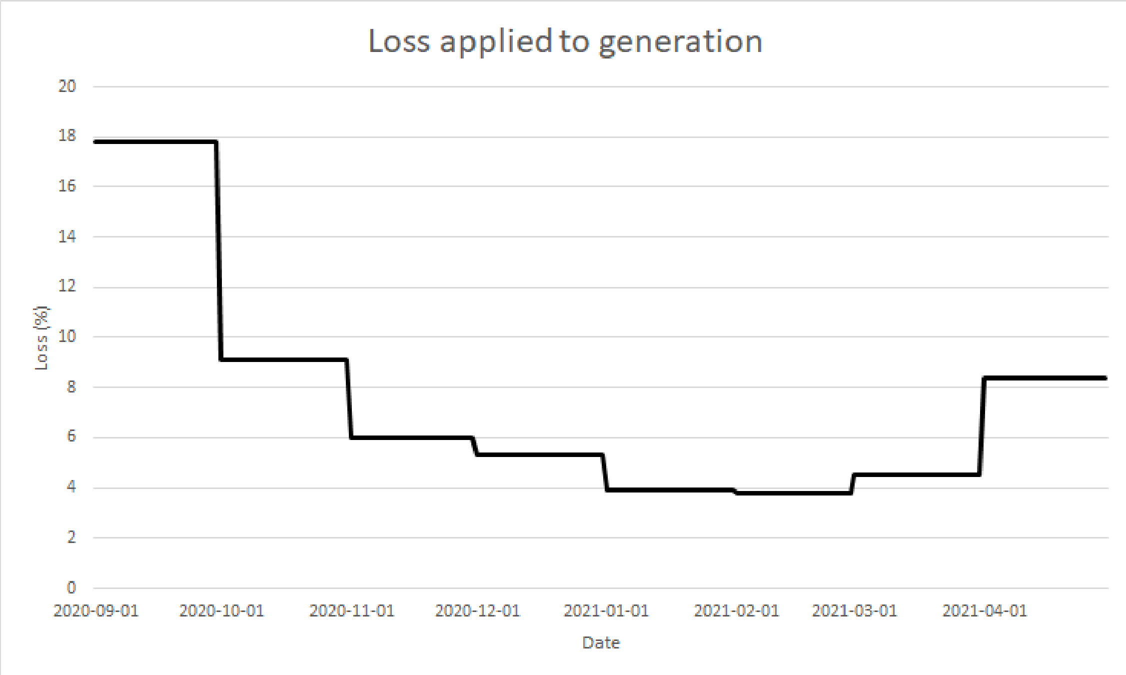

Figure 2.3: Monthly changes in generation losses

The discount rate used for all cases was set to 5% and the exchange rate used between € and Swedish krona was set to 10.07 $[SEK/€]$.

2.3 Cases and Scenarios

The model was used for two cases to evaluate the role and competitiveness of EBs. The cases were the Base case (BC), which represent the current system, and Future case (FC), that represent an assumed future system composition, yet with assumptions on input and parameters the same as in BC. The differences between the two cases can be seen in Table 2.2.

	Base case (BC)	Future case (FC)
EB Investment	Yes	Yes
Fossil fueled plants*	Yes	No
Pellet HOB investment (East, Mölndal, Sörred)	No	Yes
Rya bioCHP investment	No	Yes
Transmission Mölndal <-> Frölunda	13 MW	40 MW
Rya HOB(6&7) capacity	50.9 MW	62.0 MW

Table 2.2: Properties for Base case and Future case. *The plants removed and added can be seen in Tables A.2-A.8 in Appendix

The EBs was assumed to have an efficiency of 99% and O&M costs of 7 SEK/MWh. The investment costs for the new plants were gathered from the Danish Energy Agency 2020 [7]. For EBs the annualized cost was set to 100 $kSEK/MW$ which is an average of the two annualized costs presented in Table A.12 in Appendix. The investment cost for all pellet HOBs was set to the average of the investment costs for the two wood chip burners at 719 $kSEK/MW$ and Rya bioCHP was chosen as 662 $kSEK/MW$, economic data for the wood chip burners can be seen in Table A.13.

In FC the heat transfer capacity expansion between Mölndal and Frölunda is implemented without considering the cost of investment, i.e., the capacity is prescribed and given to the model. The same goes for capacity expansions for HOB6 and HOB7 in this scenario, which are assumed to have an additional capacity as seen in Table 2.2.

Five different scenarios (A-E) were applied to both Base case and Future case and these can be seen in Table 2.3.

Scenario	**Changes**
A: Availability	+ 10 MW electricity availability in each zones all hours + 10 MW installation capacity for all zones
B: Demand	+ 10% demand in each zone for all hours
C: No tax	$\mathrm{E}_{tax}(t) = 0 \ \forall \ t$
D: Varying tax	$\mathrm{E}_{tax}(t) = \begin{cases} 363 & \text{if} \, EC_{spot}(t) > 357 \\ \frac{363 * EC_{spot}(t)}{357} & \text{if} \, 0 < EC_{spot}(t) \leq 357 \\ 0 & \text{if} \, EC_{spot}(t) \leq 0 \end{cases}$
E: Fuel prices	Fuel prices changed according to Table A.14

Table 2.3: Scenario properties

Where $E_{tax}(t)$ is the energy tax at hour t and $EC_{spot}(t)$ is the spot price of electricity. 357 SEK/MWh is the average electricity price during the investigated period. The energy tax curve for varying tax can be seen in Figure A.8 in Appendix.

From now on, cases discussed will be named BC for Base case settings and FC for Future case settings. If a scenario is discussed on one of the cases they will be referred to as BC:A for Base case with Availability scenario etc. In total, 12 runs were performed, BC and FC and all scenarios implemented on both of the cases.

In addition, the possibility to invest in EBs was removed from Base case for one run, and the results were compared to empirical data of the DHS of Gothenburg as a model validation. The results from the validation run can be seen in Appendix.

3
Results

In this chapter the results regarding how the model responds to the introduced changes will be presented. Section 3.1 presents results regarding the economics of the EB, section 3.2 about the placement of EB, and in section 3.3 the role of the EB is presented.

3.1 Economic viability of electric boilers

For most cases EBs were installed by the model only to meet the heat demand. But increased fuel prices or lowered energy tax made the EBs economically viable. The full load hours for the scenarios where the model chose to install EBs can be seen in Figure 3.1.

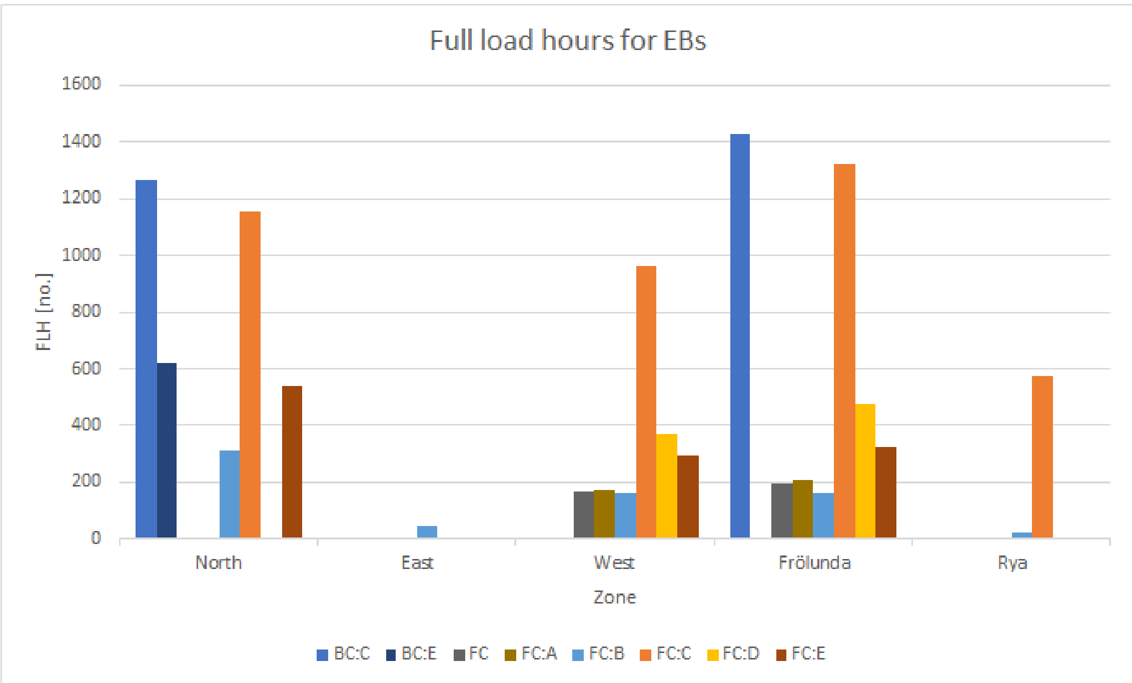

Figure 3.1: Representation of full load hours for each scenario for the investigated period

As can be seen in Figure 3.1 the model only found it economical to invest and run EBs for BC:C and BC:E. This means that there are no economical gains in installing the EBs for todays DHS if there is no change in variable costs. It can also be noted that for FC:C the FLH are significantly larger than for all other scenarios. Since the FLHs are only slightly increased for FC:A compared to FC in West and Frölunda this indicates that the availability in electricity is not the limiting factor for installing EBs, rather the variable costs impact the most.

For FC and FC:B there were little to no economical benefits for the model to run the EBs for more than to meet the heat demand which can be seen in the low amount of FLH for these cases. Looking at FC:D and FC:E, the model finds hours were it was economically viable to run the EBs due to the increased amount of FLH compared to FC.

The results from FC:C are presented in Table 3.1.

Table 3.1: Installed capacities and operating data for FC:C, Future case, no tax.

	EB North	EB Frölunda	EB West	EB Rya	Rya bioCHP
Installed capacity (MW)	36	28	77	5	65
Operating hours (no.)	1 395	1 447	1 009	585	2 345
FLH (no.)	1 158	1 326	963	572	2 323
Mean output (MW)	30	25	74	5	65
Total output (MWh)	41 297	36 745	74 419	2 674	151 890

In scenario FC:C a large amount of EBs was installed in several zones but with less capacity in the North zone compared to BC:C. However, the EBs have a higher number of full load hours in the BC:C. This indicates a larger need for heat generation overall in most of the zones for the FC:C scenario.

The results for FC:D can be seen in Figure 3.2.

Table 3.2: Installed capacities and operating data for FC:D, Future case, varying tax.

	EB Frölunda	EB West	Rya bioCHP
Installed capacity (MW)	14	45	92
Operating hours (no.)	492	382	2 943
FLH (no.)	476	371	2 913
Mean output (MW)	13	44	91
Total output (MWh)	6 473	16 730	266 763

Comparing the results from Tables 3.1 and 3.2 it can be noted that the heat generation by EBs in FC:C is replaced by investment in Rya bioCHP for FC:D. For EBs, both the installed capcities and the FLH in Frölunda and west are reduced in FC:D compared to the FC:C.

The results for FC compared to FC:E can be seen in Figure 3.2.

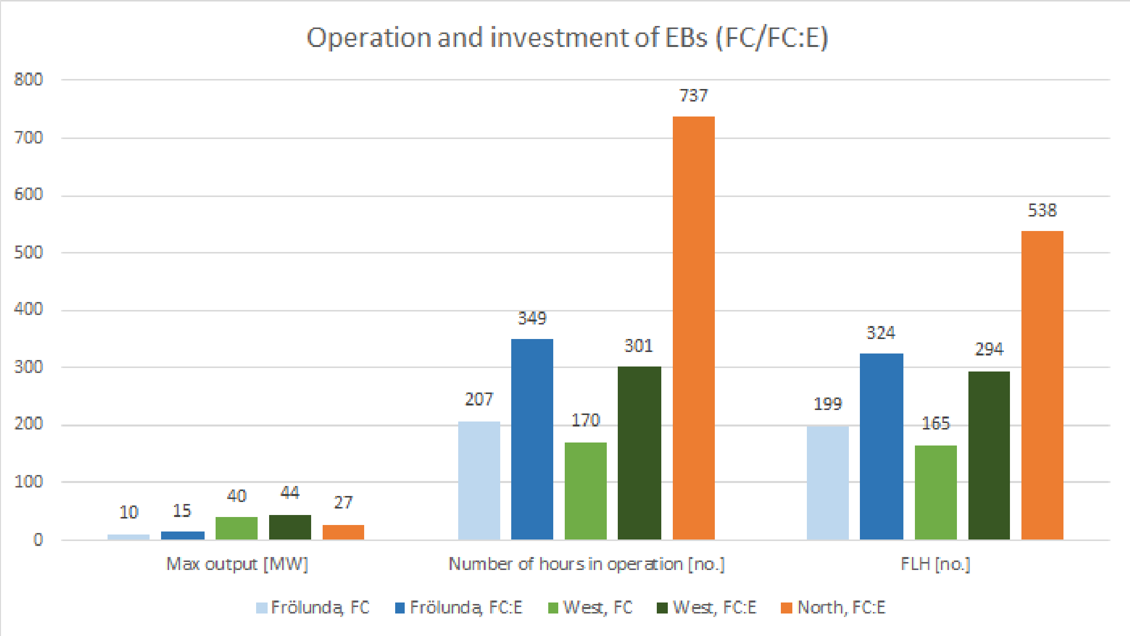

Figure 3.2: Comparison of the results from FC, Future case and FC:E, Future case, changed fuel. The Y-axis corresponds to both [MW] and [no.] depending on the variable

The model chose to install more capacity and run the EBs for a longer period of time for FC:E in both West and Frölunda. Even though these results shows economical gains in installing a larger capacity in West and Frölunda, there are no clear results as to if the originally installed capacity of 10MW for Fröunda and 40Mw for West, is fully compensated in FC:E scenario.

In Table 3.3 is a running cost comparison between the EBs and Angered HWB1-3 for different bio-oil prices presented.

Table 3.3: Percentual amount of hours where the EBs running cost is lower than Angered bio-oil HOBs for different bio-oil prices, *Fuel

	EBs cheaper than HoB [%]				
Bio-oil price [Sek/MWh*]	600	700	800	900	1000
HWB1	53 %	72 %	85 %	92 %	96 %
HWB2	71 %	86 %	93 %	97 %	98 %
HWB3	82 %	92 %	97 %	98 %	99 %

Table 3.3 shows that the EBs have a cheaper running cost than the bio-oil HOBs in North for over 50% of the hours with 600 [SEK/MWh] and HWB1. The price for bio-oil was set to 640 [SEK/MWh] for all scenarios except for BC:E and FC:E which had the price of 1000 [SEK/MWh]. Since the North zone only contains bio-oil boilers, this analysis shows that it is vulnerable to increased bio-oil costs and that EBs can have lower variable costs and act both as peak and intermittent depending on availability and price of electricity.

In Table 3.4 are the results for installed EBs for FC:A compared to FC presented.

Table 3.4: Installation and operating data for EBs in FC, Future case in relation to FC:A, Future case with increased availability.

	EB West		EB Frölunda	
	[MW]	[%]	[MW]	[%]
Installed capacity	-16.5	-41	9.9	103
Operating hours	2	1.2	-1	-0.5
FLH	5.7	3.5	3.1	1.5
Mean output	-15.5	-40	9.9	107
Total output	-2 595	-40	2 025	106

The results from Table 3.4 shows that an increased availability of electricity doesn't make the EBs run for additional hours, but some of the installed capacity is moved from West to Frölunda.

3.2 Placement of the electric boilers

In Figure 3.3 are the installed capacities for EBs.

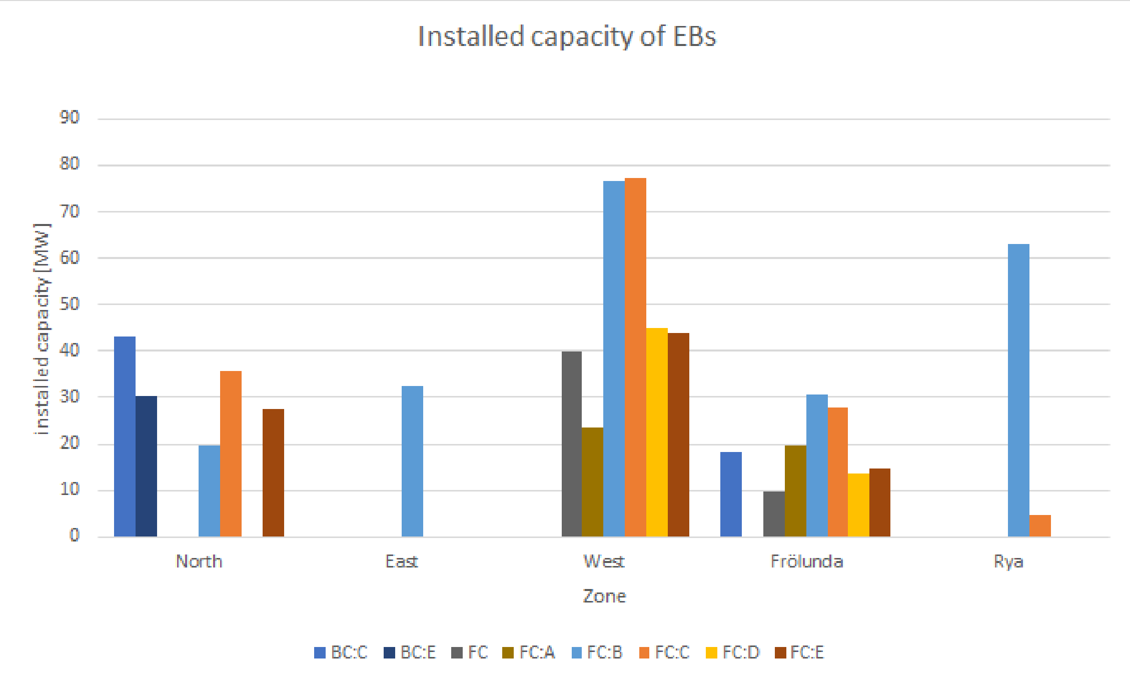

Figure 3.3: Installed EB capacities for all cases

As Figure 3.3 shows the model mainly chose to install EBs in West, Frölunda and North. Cases: BC, BC:A, BC:B and BC:D did not install any EBs. It is notable that cases FC:B and FC:C installed the highest total capacity, but looking at the FLHs for FC:B shown in Figure 3.1, it is clear that there is a large need for peak heat generation and that EBs can handle some of these peaks but with no economical benefits.

For FC the model chose to install electric boilers in Frölunda and in West. The installed capacities and running data can be seen in Table 3.5.

Table 3.5: Electric boiler data FC, future case

	Frölunda	West
Installed capacity (MW)	10	40
Operating hours (no.)	207	170
FLH (no.)	199	165
Mean output (MW)	9	39
Total output (MWh)	1906	6613

Table 3.5 shows that there is a need for additional heat generation in West and Frölunda for FC, and that EBs can provide some of that heat. FC is not able to meet the demand in Frölunda and Sörred. In Frölunda one hour with 1.24MW is

missing due to that import and that the electricity availability for EBs was not enough for that hour. In Sörred, 13 hours with an average output of 2.49MW and max of 6.26MW is missing due to lack of heat generation and no possibility to install more. A comparison between BC and FC can be seen in Table A.15 in Appendix.

The FC:A affected the placement and heat generation of EBs which is presented in Figure 3.4.

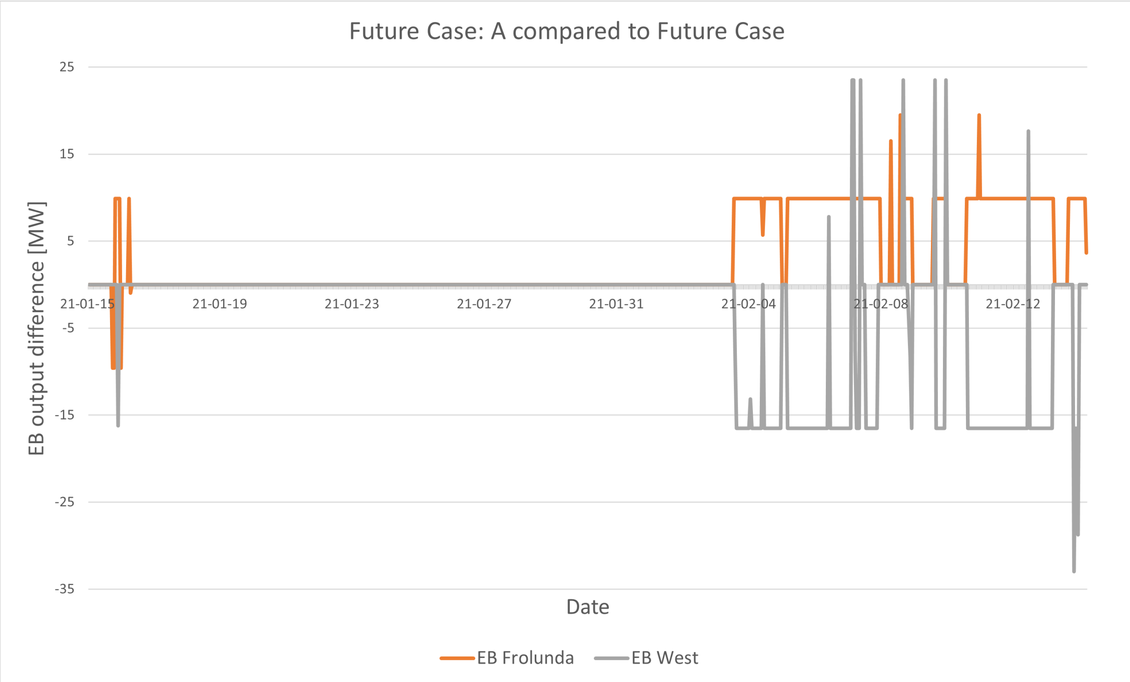

Figure 3.4: Differences in EB generation for Frölunda and West for FC:A, Future case, availability and FC, Future case. Period 21-01-15 to 21-02-14.

Figure 3.4 depicts the heat generated by EBs for FC:A minus heat generated by EBs for FC. From Figure 3.4 it can be noted that the heat generation in West for FC, is moved to Frölunda for FC:A for the corresponding hours.

3.3 The role of electric boilers in the DHS of Gothenburg

Some scenarios that either lowers the running costs of EBs or increases the running costs of other plants make the EBs run either as peak or intermittent heat generation. This is shown in Figure 3.5 where heat generation for the EBs and the new Rya bioCHP is presented for FC:C. For both Figure 3.5 and 3.6 is the demand and electricity price connected to the secondary axis to the right in the figures, the heat generated by EBs and CHP is related to the main axis to the left. The figures only represent the heat generated by new EBs and the new CHP in Rya, but the heat demand is met by other types of already installed heat generation.

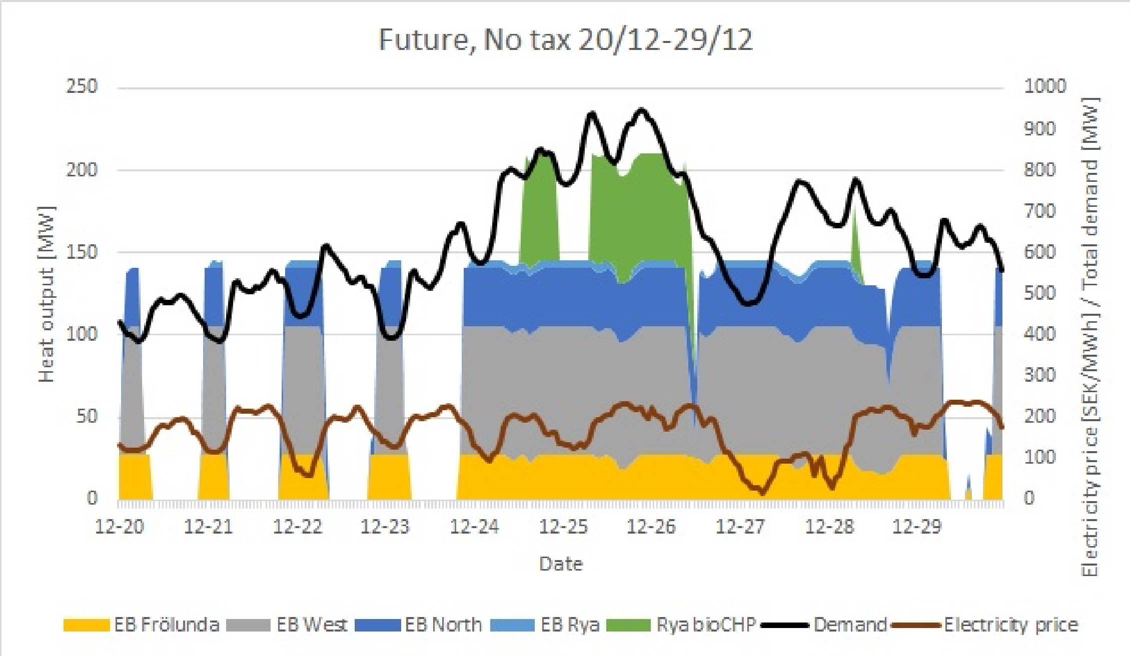

Figure 3.5: FC:C Future case, No tax. Period 20-12-20 to 20-12-29.

As can be seen in Figure 3.5 the EBs act as intermittent heat generation depending on demand, electricity price and electricity availability. The CHP in green is only used when the demand increases and when the electricity price peaks during this period. In Figure 3.6 are the results from a period of higher demand in December presented for FC:C

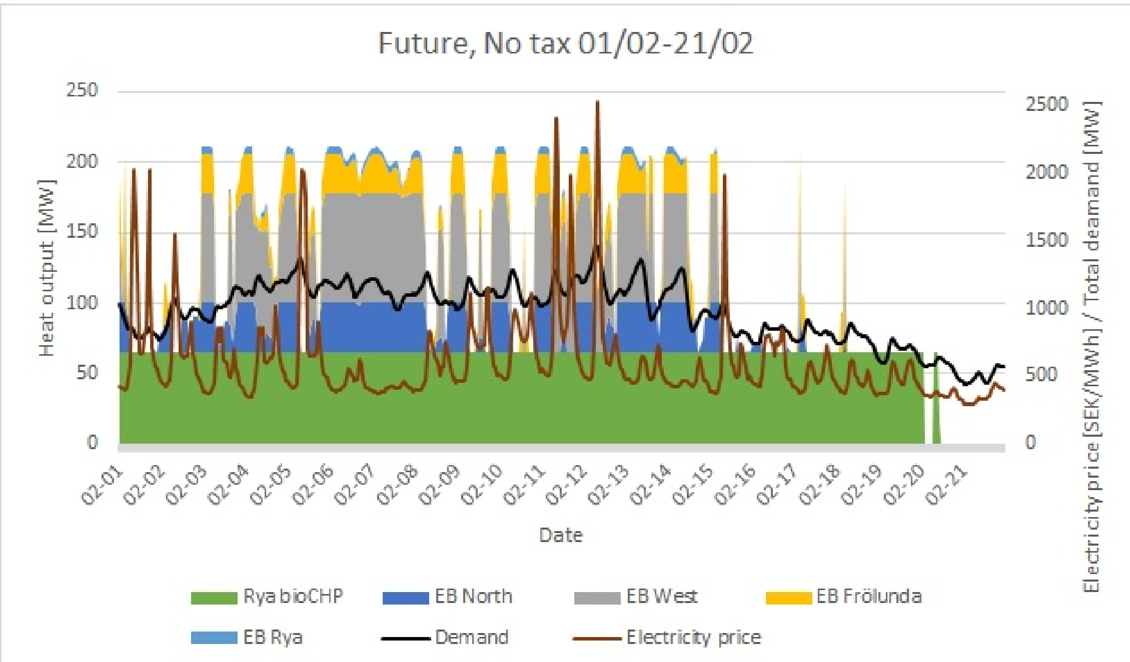

Figure 3.6: FC:C, Future case, No tax. Period 21-02-01 to 21-02-21.

It can be seen in Figure 3.6 that during the colder periods in February, the electricity price increased compared to Figure 3.5 and the CHPs run as base heat generation while the EBs now act as peak load. When comparing the two periods in Figure 3.5 and 3.6 it can be seen that the EBs still act as intermittent/peak loads for lower electricity prices during the period when there is available electricity. The CHP now act as base heat generation during the colder period in February with higher electricity prices and increased heat demand.

The availability, demand and electricity price as well as heat generation from EBs for the North zone can be seen in Figure 3.7. The results presented are take from the coldest days during the investigated period.

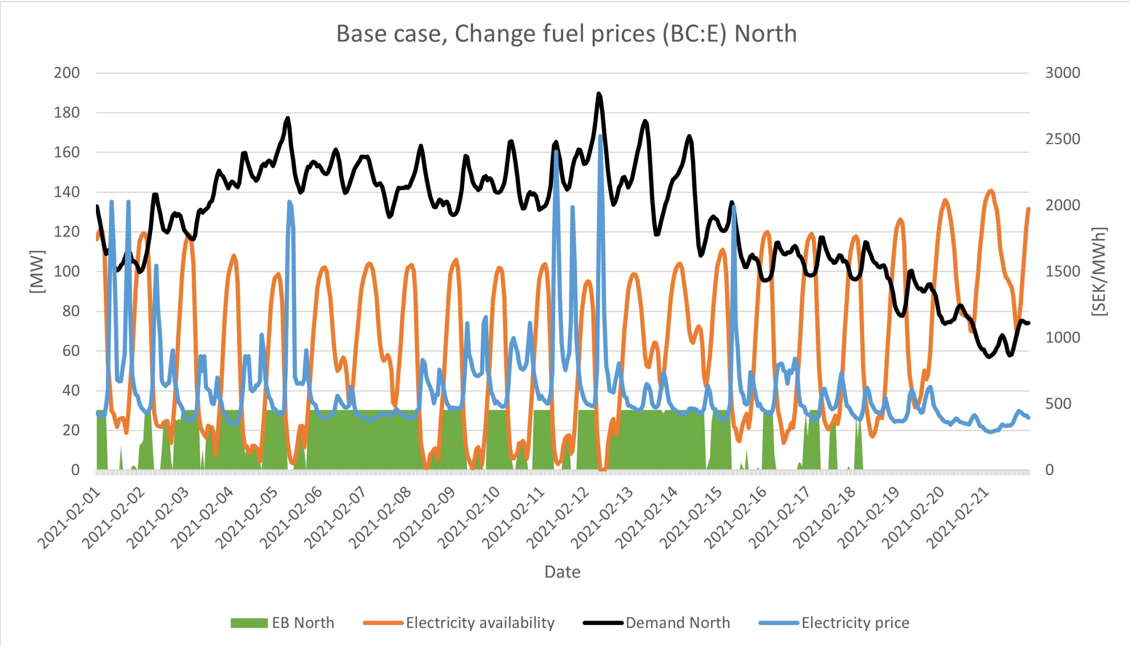

Figure 3.7: North Comparison of electricity availability in, heat demand and electricity price as well as heat generation for EBs. Period 21-02-01 to 21-02-21.

Figure 3.7 shows a connection between electricity price and availability and a difference in availability between weekdays and weekends (06/02-07/02 & 13/02-14/02). It can be seen that the availability is higher during low electricity prices and lower during high electricity prices and this trend can be seen for all zones in Figures A.7-A.9 in Appendix. The increased availability and low price correlation provides potential for the EBs to act flexible during the low cost hours which the model also chose to do as seen in green.

The percentual availability for EBs over the studied period, with a specified installed capacity in each zone are presented in Table 3.6.

Table 3.6: Electricity availability [%] depending on installed EB capacity, for September 2020-April 2021

Installed capacity	North	East	Frölunda	Rya/West
10 MW	99.35	100.00	98.97	99.98
20 MW	98.07	99.95	91.70	99.88
30 MW	95.52	98.52	75.67	99.85
40 MW	92.73	96.33	55.17	99.76
50 MW	87.83	91.39	23.26	99.24
60 MW	81.39	78.00	4.67	97.43
70 MW	74.95	61.66	-	92.60
80 MW	68.04	47.74	-	86.74
90 MW	60.11	34.04	-	79.84
100 MW	50.93	18.42	-	72.19

Table 3.6 shows that there is capacity available in the electricity grid for a high amount of hours in each zone for various installed output capacities for EBs. This enables the EBs to act both as intermittent, peak and backup heat generation during the hours with available electricity. It shall be noted that the hours with high demand of heat often correlate with low availability in electricity.

4
Discussion

Even though there are no economical gains in running the EBs with base case settings, there are other possibilities for the EBs to support the DHS. The clear trend in diurnal changes of electricity availability gives a possibility for EBs to act as backup heat generation. To further increase the potential of EBs, additional heat storage could be installed to utilize the available electricity when there is a supply. Heat storage may however compete with EBs, since the other installed heat generation may also use the heat storage to compensate for load variations.

The results show that there are hours with severely reduced electricity availability which limit the possibility for EBs to generate heat on demand. But due to fuel deliveries being harder to receive during the weekends, and a trend in increased availability of electricity, this improves the possibility for EBs to act as a backup heat generation during weekends especially.

For the Base case with changed fuel prices, the model chose to install EBs in the North zone. Since the North zone relies heavily on bio-oil HOBs, an increase in bio-oil prices can affect the running cost drastically. This makes it interesting to evaluate new installment of boilers in the North zone to complement the existing heat generation. It is also favorable to implement an EB to act as backup, since the heat provided by northern industries is not something that Göteborg Energi AB can affect but may have to adapt to. Looking at the availability in North and price comparison to Angered plants it can be seen that there are reasons to investigate an implementation of EBs in the North for both economical gains and security of heat delivery.

Through discussion with Göteborg Energi AB, they confirmed that the fuel prices have increased since the investigated period. It is also risky to rely on a few different fuels for heat generation, and by installing EBs as backup heat generation, their fuel-diversity can be increased. If the EBs are installed as backup heat generation they can be used as complementing heat generation as well, producing heat during low price hours and assuming there is demand or a possibility to store heat. This will help the EBs compensate for some of the investment costs.

The exact placements of the EBs are not taken into account due to lack of information about transformer stations locations and DHS grid. If Göteborg Energi AB want to install EBs the placements needs to be investigated further. Since some of the plants that run on fossil fuel are being decommissioned, these locations could be potential new placements for EBs, regarding that there is a transformer close by.

Some of the plants were shut off for the Base case to make the model more realistic since they were not in operation during the investigated period. Also, restrictions such as noise level, operating hours etc. were neglected in this study which may have an impact on how the model compares to reality. These restrictions imply that even if Göteborg Energi AB run a plant based on restrictions, the model might choose differently solely based on economic gains.

Also, by not including start-up costs, minimum load, ramp up- and ramp down regulations, dynamic effects of heat generation could not be evaluated fairly. Adding these constraints could further improve the usability of EBs, since they are cheaper and faster at regulating output than combustion HOBs and CHPs.

Since this model is a first draft of a multi-zone DHS model, there are several assumptions that can be further evaluated to improve the model for future studies. To be able to evaluate different time periods, the model always needs to be fed data to be able to evaluate the possibilities for EBs. The availability and electricity price is closely linked together and will impact the model result if both are not changed accordingly. Something that may have an impact on the results, is that the investigated period occurred during a pandemic that affected the behaviours and daily routines of everyone. This can have an impact on the demand curve for both heat and electricity.

For future studies it would be interesting to look at the possibility of installing HPs instead of EBs. This study would need to focus more on actual placements of the HPs due to the need for external heat sources such as sewage water or similar, to boost the COP and be able to supply high enough temperature. If there are locations where HPs could be placed, the system could use the electricity more efficiently and produce more heat. This also leads to questions about the future of flexible electricity usage in general. A multi-zone investigation of possible other consumers, which can interfere with the usage of EBs, could evaluate how to use the electricity either most efficiently or to benefit the city the most. This is interesting since producing one unit of heat using one unit of electricity is regarded as a large drop in exergy.

5 Conclusion

With current fuel prices and electricity tariff system there are low economic incentives to invest in EBs, nor are there any need for them to supply the demand in the current DHS. However, there are scenarios in which the EBs can operate both economically and support the DHS. The EBs often take the role of peak heat generation but with increased fuel prices or decreased running cost for EBs, it can instead act as a complementing heat generation to both HOBs and CHPs.

For all zones where EBs are investigated, there are possibilities for the EBs to act as a backup heat generation for most of the hours. It can be concluded that West, Frölunda and North zone are of interest when looking at installing EBs. In North it is interesting since the results imply that it is economically viable to install about $30MW$ of EB, if the fuel prices for bio-oil increases. For future cases, in West and Frölunda the results point to a need in new heat generation in both zones to be able to supply the demand. The EBs may be able to support the DHS in these two zones as a peak/backup heat generation. The Frölunda zone is however more constrained when it comes to electricity availability which impacts the usability of EBs in this zone.

We recommend that Göteborg Energi AB further investigates possible placements of EBs in the North and West zone and evaluates the economic impact as well as the effects it may have on the DHS of Gothenburg. Depending on the impact of the increased transmission capacity between Frölunda and Mölndal as well as future electricity grid installations in Frölunda, the implementation of EBs in Frölunda might also be worth investigating.

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A

Appendix 1

A.1 Model data

Table A.1: Heat demand temperature, -16 °C and respective share of that total heat demand with and without Mölndal. The heat demand was divided according to the shares with Mölndal and the grid network capacity was divided to the shares without Mölndal.

Zone	Heat demand at $-16°C$ [MW]	Share with Mölndal	Share without Mölndal
North	207	0,129	0,140
East	283	0,176	0,192
West	495	0,308	0,335
Frölunda	163	0,101	0,110
Rya	248	0,154	0,168
Sörred	80	0,050	0,054
Molndal	130	0,081	-
Total	1606	1	1
Total without Mölndal	1476		

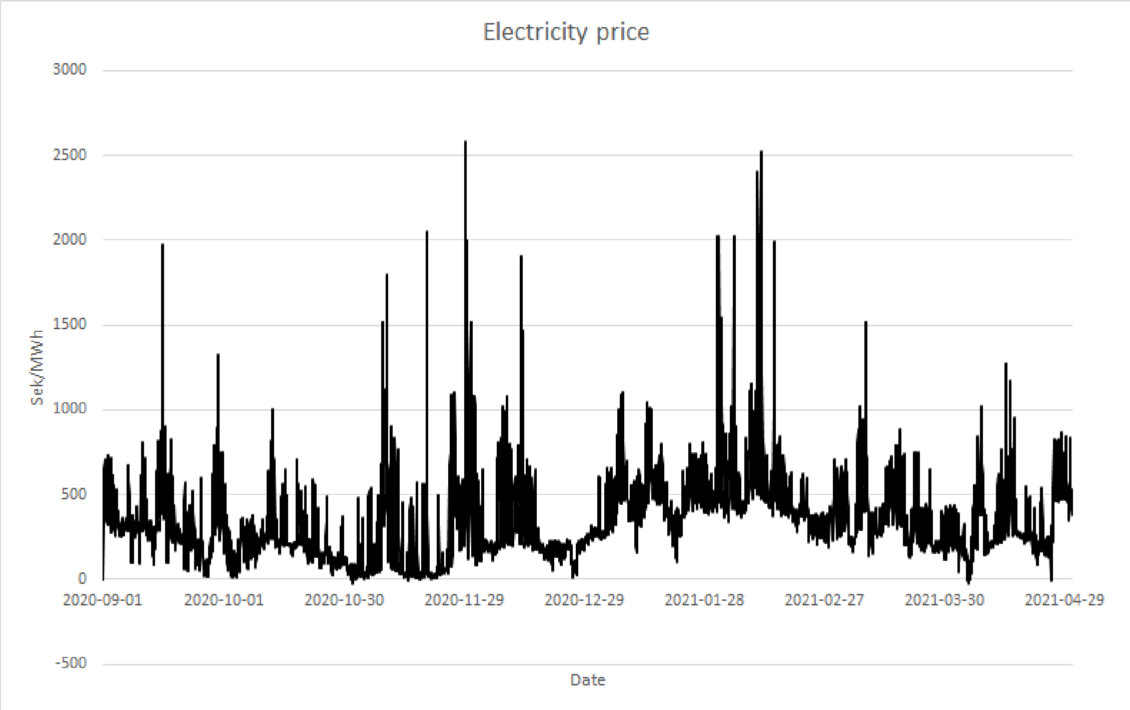

Figure A.1: Price curve for electricity during the investigated 2020-2021 period

A.2 Plant properties

Table A.2: Plant properties, North

Plant	Capacity [MW]	Fuel	Efficiency	Alpha	Max. full load hours
Angered HWB1	38	Bio-oil	0,84	-	1500
Angered HWB2	33	Bio-oil	0,73	-	1500
Angered HWB3	30	Bio-oil	0,66	-	1500

Table A.3: Plant properties, East 1: Removed for Future case 2: Implemented for Future case 'Heat output over fuel input.

Plant	Capacity [MW]	Fuel	Efficiency	Alpha
Sävenäs HWB1	83	Biogas	0.90	-
Sävenäs HWB2	80	Oil	0.90	-
Sävenäs CHP3	80	Wood chips	0.90'	0.11
Backa *PP1*[1]	12	Oil	0.88	-
Backa *PP2*[1]	12	Oil	0.88	-
Backa *P16*[1]	8	Oil	0.88	-
Sävenäs new *pellets*[2]	80	Pellets	0.93	-

Table A.4: Plant properties, West 1: Removed for Future case

Plant	Capacity [MW]	Fuel	Efficiency	Alpha
Rosenlund HWB2[1]	140	Oil	0.90	-
Rosenlund HWB3[1]	140	Oil	0.901	-
Rosenlund HWB4[1]	140	Oil	0.902	-
Rosenlund HWB5[1]	140	Natural gas	0.903	-

Table A.5: Plant properties, Frölunda. 1: Removed for Future case 'Heat output over fuel input. Sisjön P15,P13 and P11 has a maximum total heat output of 12 000 MWh each year.

Plant	Capacity [MW]	Fuel	Efficiency	Alpha
Sisjön P15	8	Bio gas	0.96	-
Sisjön P13[1]	8	Oil	0.95	-
Sisjön P11[1]	5	Oil	0.95	-
Tynnered HWB1[1]	10	Oil	0.90	-
Tynnered HWB2[1]	10	Oil	0.90	-
Högsbo CHP[1]	15.9	Natural gas	0.41'	0.81

Table A.6: Plant properties, Rya. 1: Removed for Future case 2: Implemented for Future case 3: Heat output over fuel input. 4: Coefficient of performance

Plant	Capacity [MW]	Fuel	Efficiency	Alpha
Rya HWB6	50.9	Pellets	0.93	-
Rya HWB7	50.9	Pellets	0.93	-
Rya CHP[1]	294	Bio gas	0.49'	0.88
Rya HP1	30	El.	3.60[3]	-
Rya HP2	30	El.	3.34[3]	-
Rya HP3	50	El.	3.10[3]	-
Rya HP4	50	El.	3.51[3]	-
Rya new bioST[2]	142	Mixed wood	1.01[4]	0.26
	Size [MWh]	Effect in/out [MW]	Efficiency	SOC_{loss}
Acc. tank	1000	150	0.999	$\sqrt[24]{0.99}$

Table A.7: Plant properties, Sörred. 1: Removed for Future case 2: Implemented for Future case

Plant	Capacity [MW]	Fuel	Efficiency	Alpha
Sörred HWB[1]	70	Bio gas	0.90	-
Sörred new pellets[2]	40	Pellets	0.93	-

Table A.8: Plant properties, Mölndal. 2: Implemented for Future case

Plant	Capacity [MW]	Fuel	Efficiency	Alpha
Riskulla CHP	99.75	Mixed wood	0.87	0.27
Riskulla HWB1	38	Pellets	0.84	-
Riskulla HWB2	52	Bio-oil	0.95	-
Riskulla new pellets[2]	50	Pellets	0.93	-

Table A.9: Fuel cost 2020-2021 *Fuel

Fuel	Cost (sek/MWh*)
Bio gas	400
Natural gas	250
Pellets	312
Bio-oil	641
Oil	340
Wood chips	209
Mixed wood	270
Excess heat	100

A.3 Electricity availability

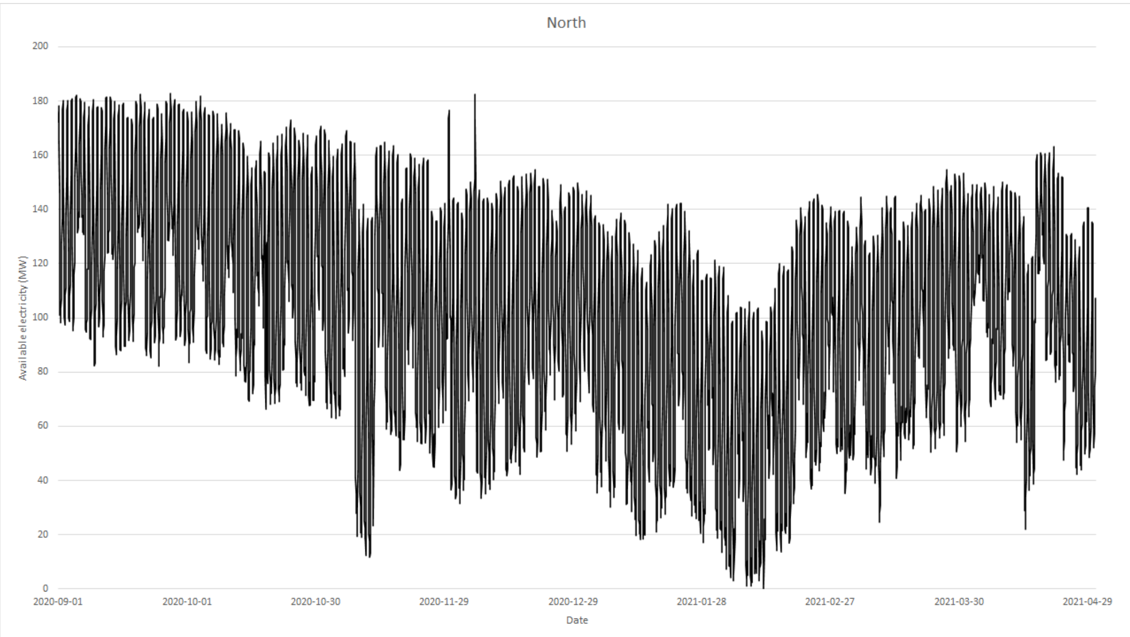

Figure A.2: Available electricity in North region

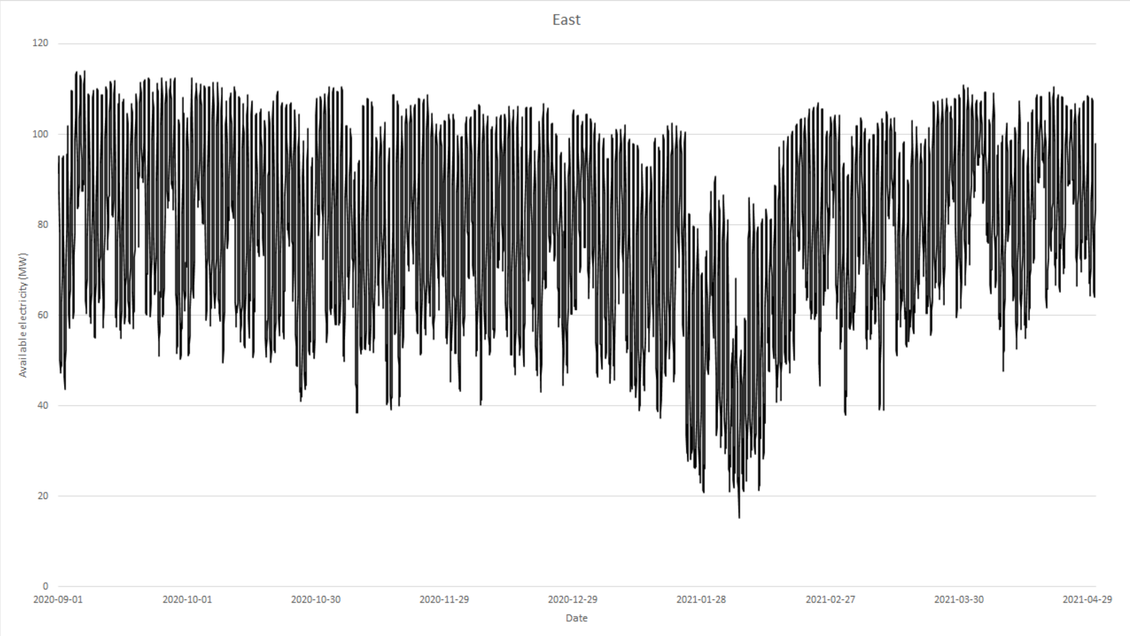

Figure A.3: Available electricity in East region

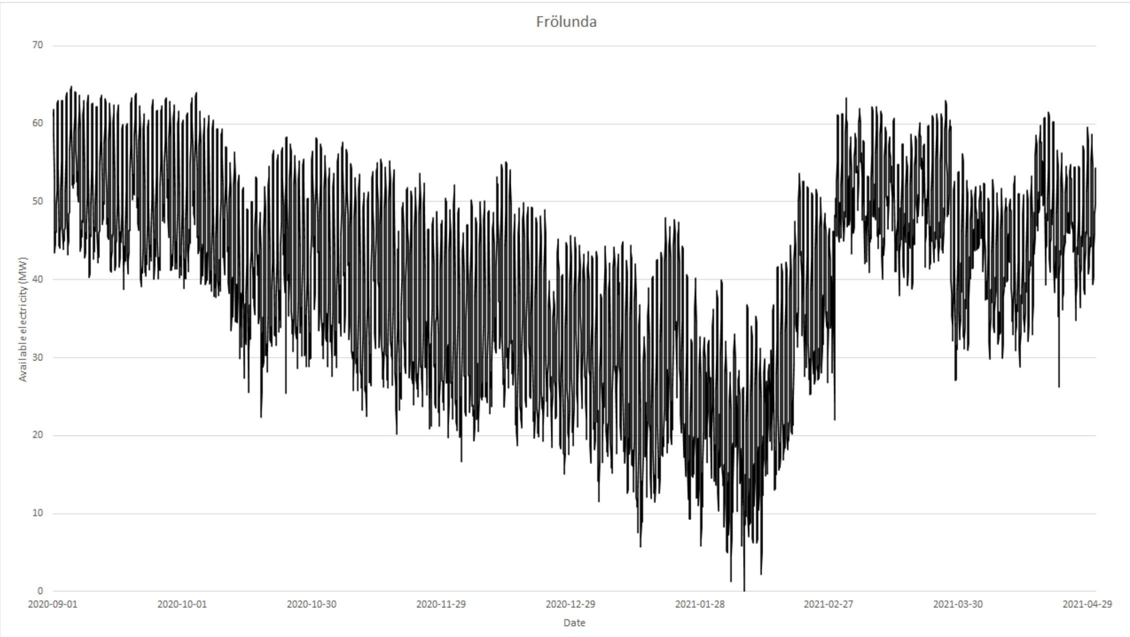

Figure A.4: Available electricity in Frölunda region

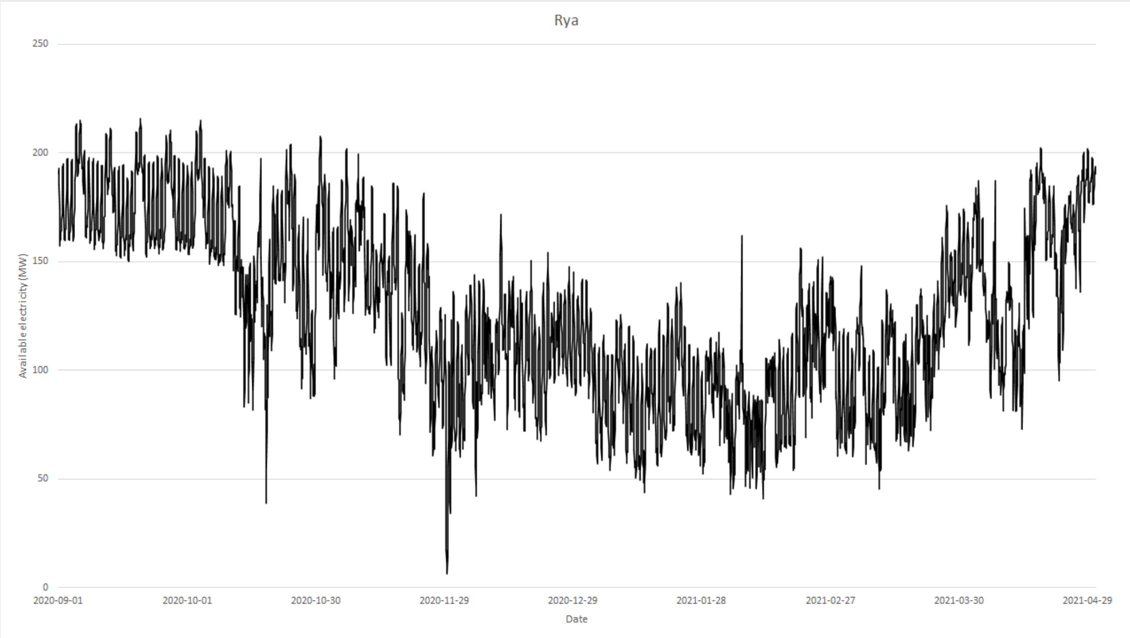

Figure A.5: Available electricity in Rya region

A.4 Transmission limitations

Table A.10: Transmission limitations between the zones in the model. Units in MW *Changes from 110 to 137 and 13 to 40 for future case

From\To	North	East	West	Frölunda	Rya	Sörred	Mölndal
North	-	60	-	-	-	-	-
East	100	-	69	-	-	-	-
West	-	-	-	110*	-	-	30
Frölunda	-	-	-	-	-	-	13*
Rya	-	230	500	-	-	-	-
Sörred	-	-	-	-	40	-	-
Mölndal	-	-	30	13*	-	-	-

A.5 Grid accumulation

Table A.11: Grid accumulation as well as the charge and discharge effect of each zone.

Zone	Max capacity (MWh)	Charge (MW)	Discharge (MW)
North	70	10.5	10.5
East	96	14.4	14.4
West	167	25.1	25.1
Frölunda	55	8.3	8.3
Rya	84	12.6	12.6
Sörred	27	4.1	4.1
Mölndal	0	0	0
Total	499	75.0	75.0

A.6 Investments costs

Table A.12: Economical aspects for EBs. *Installed output **Operation and maintenance costs

	1-5 MW*	>10MW*
Investment cost [M€/MW*]	0.15	0.07
Fixed OM** [€/MW*]	1070	1070
Technical lifetime [years]	20	20
EAC [Sek/MW*]	132 000	67 000

Table A.13: Economical aspects for wood chip burners. *Installed output **Operation and maintenance costs

	45MW Wood Chip	90MW Wood Chip
Investment cost (M€/MW*)	0.49	0.44
Fixed OM** (€/MW*)	42 000	34 600
Technical lifetime (years)	25	25
Annual investment cost (Sek/MW*)	776 000	662 000

A.7 Future fuel prices

Table A.14: Future prediction on Fuel cost. *Fuel

Fuel	Cost (sek/MWh*)
Bio gas	775
Natural gas	1100
Pellets	400
Bio-oil	1000
Oil	893
Wood chips	256
Mixed wood	340
Excess heat	100

A.8 Energy tax

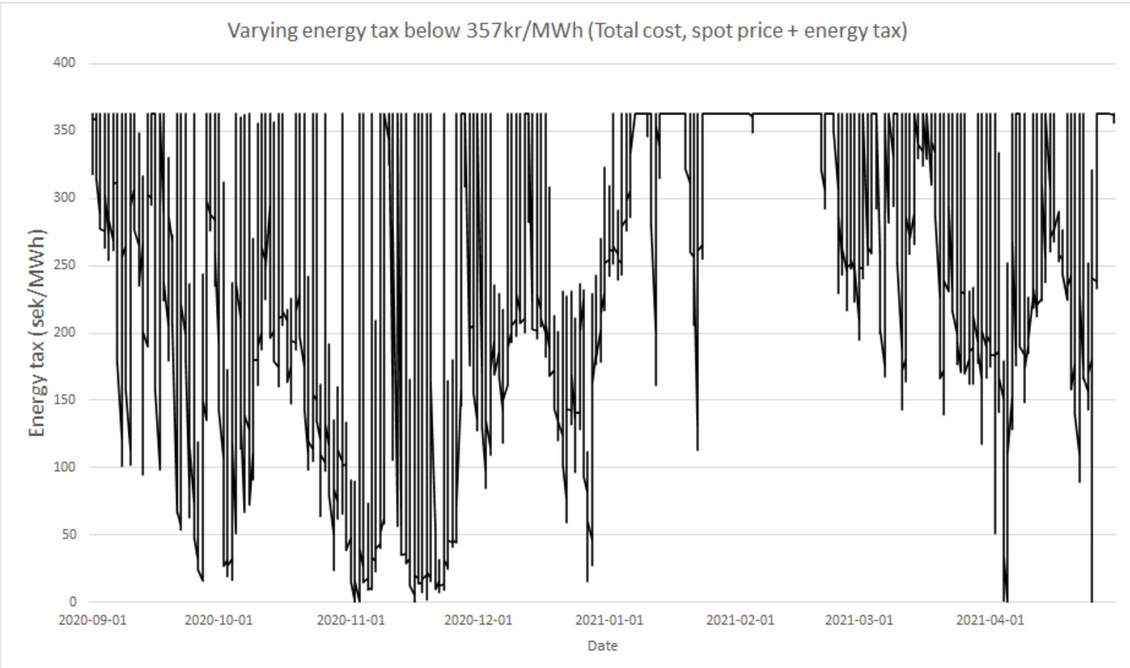

Figure A.6: Varying energy tax scenario

A.9 Results

Table A.15: Future case result compared to Base case

	Future	Base case
Generation North (GWh)	57	55
Generation East (GWh)	1 230	1 272
Generation West (GWh)	11	12
Generation Frölunda (GWh)	6	38
Generation Rya (GWh)	1 543	1 514
Generation Sörred (GWh)	177	173
Generation Mölndal (GWh)	440	402
Total Generation (GWh)	**3465**	**3466**
Total Cooling (MWh)	0.01	0.12
Total losses (%)	8.97	9.00
Heat not delivered (GWh)	0.03	-

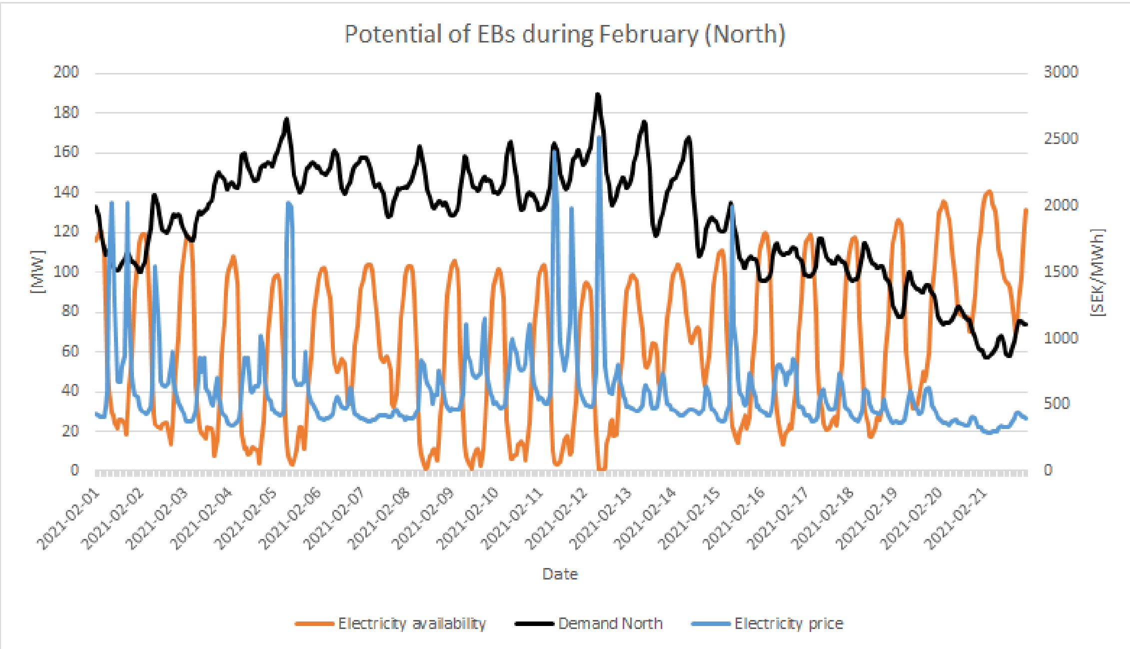

Figure A.7: Electricity availability/price and demand comparison for the North zone

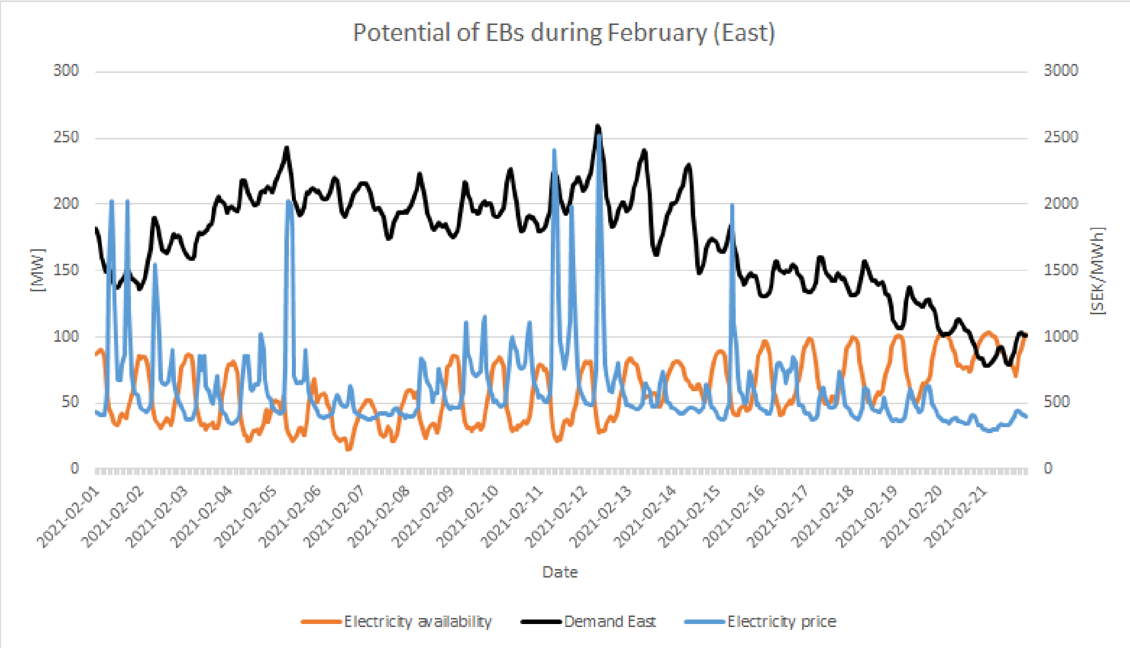

Figure A.8: Electricity availability/price and demand comparison for the East zone

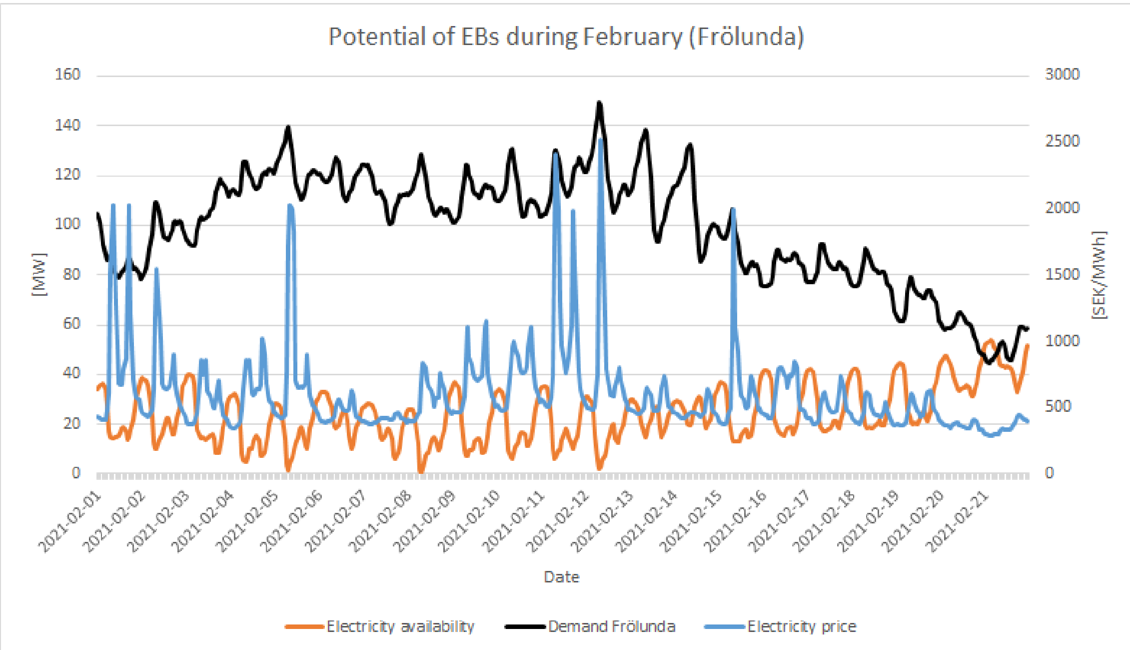

Figure A.9: Electricity availability/price and demand comparison for the Frölunda zone

A.10 Validation of the model

Table A.16 presents the results from BC and from the actual production.

Table A.16: BC, Base case result compared to actual generation reference during the investigated time period

	Model results	Reference
Generation North (GWh)	55	51
Generation East (GWh)	1272	1391
Generation West (GWh)	12	46
Generation Frölunda (GWh)	38	15
Generation Rya (GWh)	1514	1553
Generation Sörred (GWh)	173	148
Generation Mölndal (GWh)	402	376
Total Generation (GWh)	**3466**	**3580**
Total Cooling (GWh)	0.12	-
Total losses (%)	8.92	-

Comparing the results from BC with the actual production it is seen that for most zones the production is similar. Looking further into Frölunda, the zone that differs the most, Figure A.10 show the generation from the model och A.11 the actual generation.

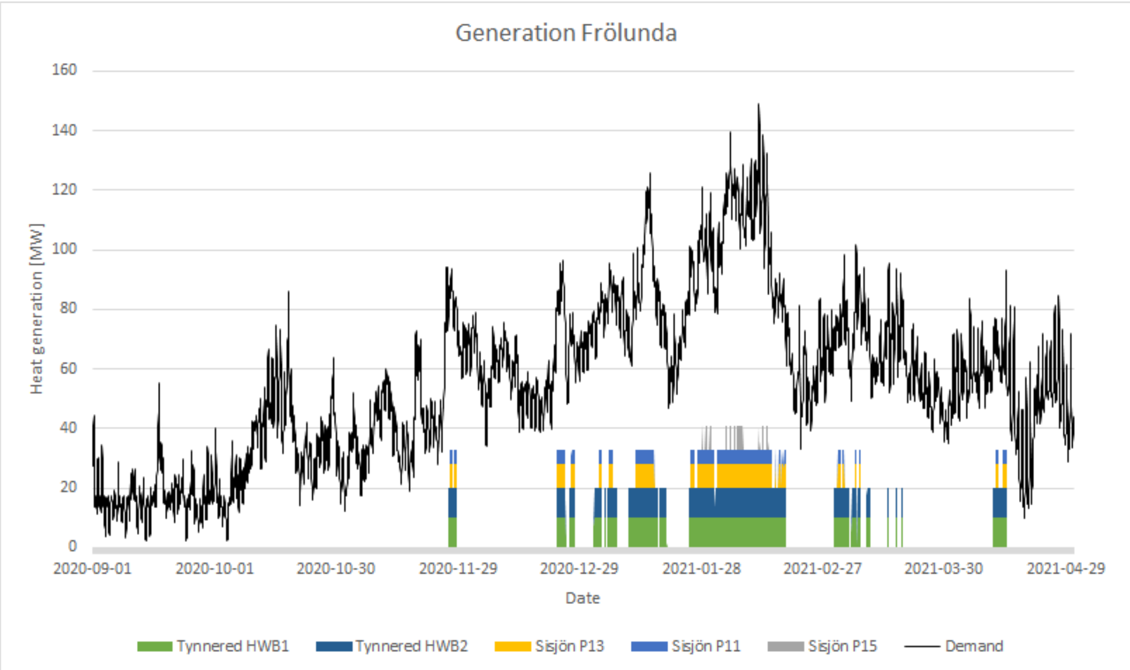

Figure A.10: Generation in Frölunda for BC, Base case

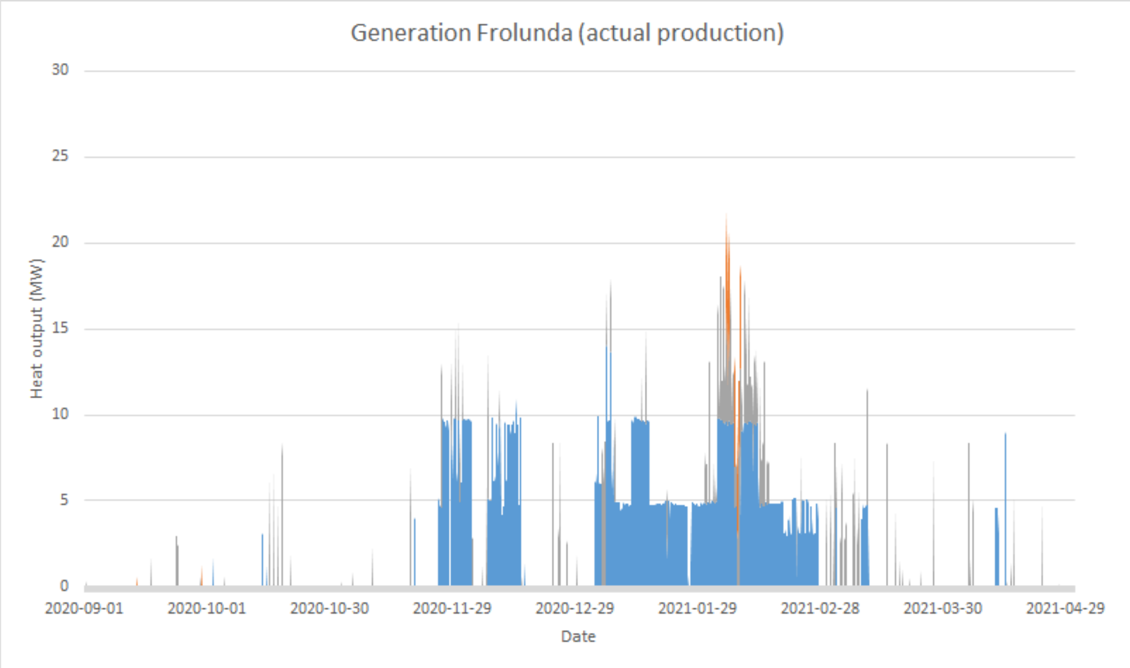

Figure A.11: Actual production in Frölunda during the investigate period

It can be deducted from comparing the figures that model chose to run more plants in Frölunda and for a longer period of Time.

Looking at Rya, more similarities were found in total output, running time as well as instantaneous heat output. In figure A.12 are the results from the model presented along side the actual generation in A.13.

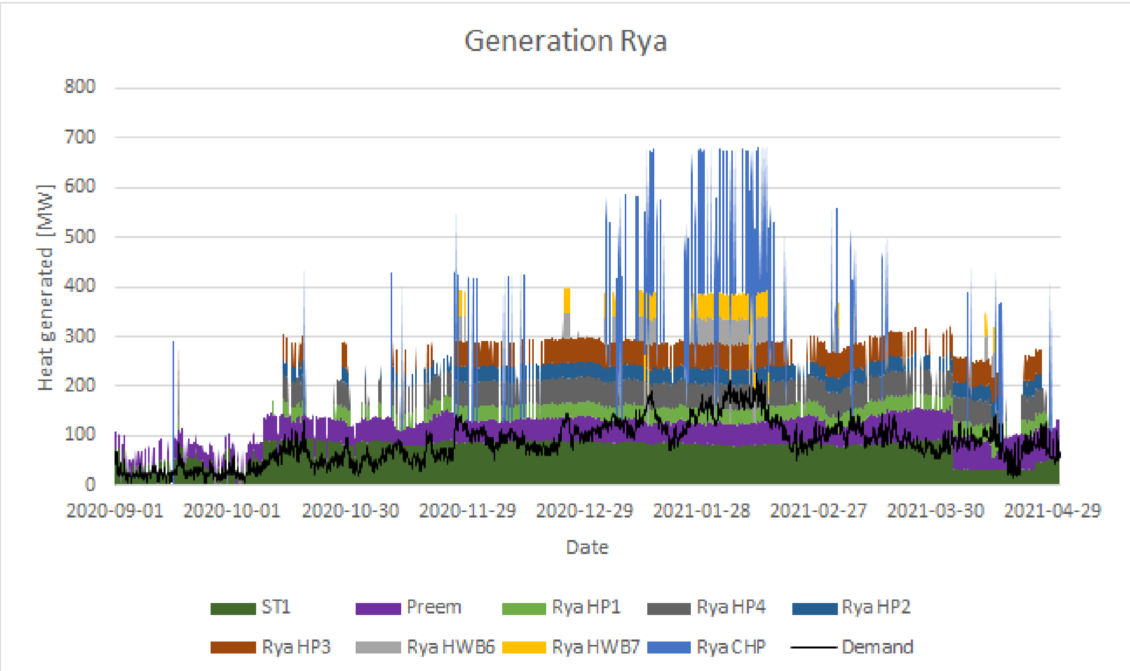

Figure A.12: Generation in Rya for BC, Base case

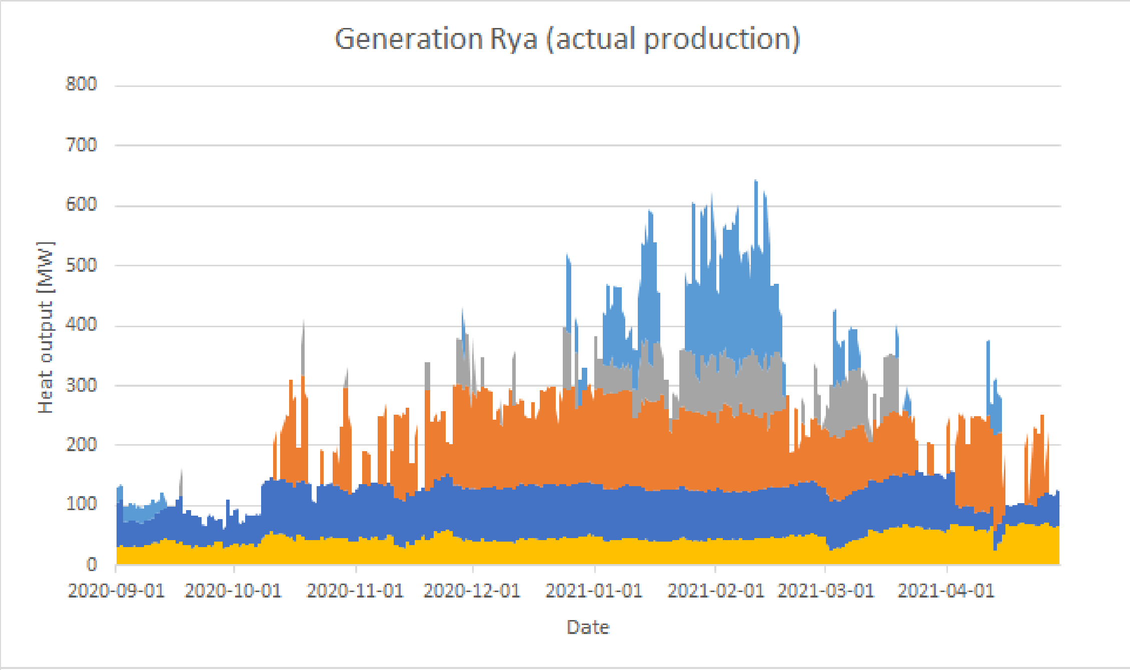

Figure A.13: Actual production in Rya during the investigate period

Transmission losses each month for the base case without EBs are presented in Figure A.14 together with the transmission losses for 2018 and 2019 for the DHS in Gothenburg.

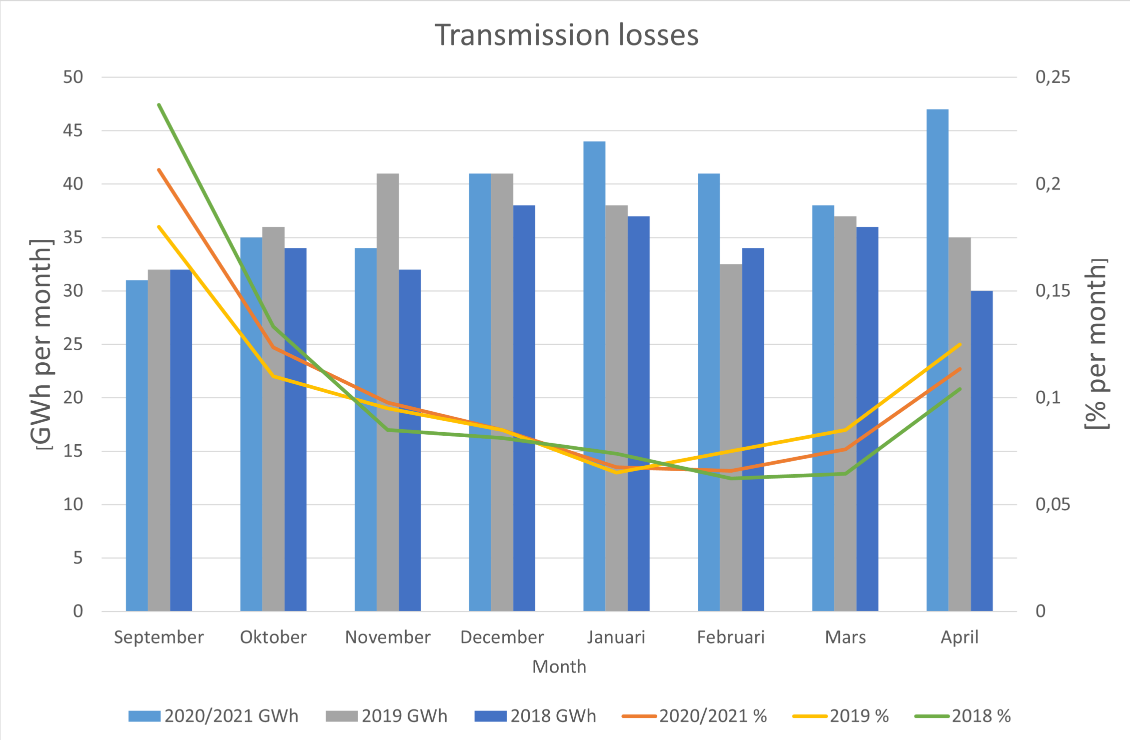

Figure A.14: Losses in the DHS in GWh and in percentage per month. The values for 2018 and 2019 are data from Göteborg Energi AB and for 2021/2021 is from the validation case of the model.

Figure A.14 shows that the losses in the model corresponds closely to the measured values from Göteborg Energi AB.

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