The role of heat storages in facilitating the adaptation of DH systems to large amount of variable RES electricity

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Abstract:

In Finland district heating accounts for almost half of the total heating market and over 70 % of the district heat is produced with combined heat and power (CHP) plants. Energy and climate policies aim especially to increase the share of renewable energy in the future energy systems. Large shares of variable power generation will increase the volatility in electricity prices that in turn will impact CHP production as well as heat production with heat pumps. As a consequence thermal energy storages and heat pumps could have an increasingly important role in future district heating (DH) networks. The paper explores the optimal dimensioning of heat storages, heat pumps and solar collectors. In order to do this, we perform the optimal hourly scheduling of heat production and storage in the DH network of Järvenpää and Tuusula (78,000 inhabitants) in Southern Finland in 2050. These results are used to find the most cost effective combinations of the aforementioned district heating technologies. The studied DH network includes both CHP plant, fired mainly by biomass and heat only boilers. As future electricity prices are highly sensitive to the future shares of wind power and PV, we study three different scenarios with varying shares of wind power and PV (40% and 60%) in 2050. When the impacts of different system components were analyzed separately, it was found that a small heat storage is not a profitable investment but a larger heat storage (100,000 - 110,000 m^3) is economical. In addition, the results indicate that the most economical size for a heat pump is around 20 – 25 MW. Yet, the most profitable solution was to include both a heat storage and a heat pump in the DH system. According to our results, solar collector was not a profitable investment in the studied DH system.

Keywords:

District Heat, Renewable Energy, Thermal Energy Storage, Heat Pump.

1 Introduction

In Finland, the most common form of heating is district heating and it accounts for almost half of the total heating market. In 2014, around 35 TWh of district heat was produced in Finland and approximately 72 % of it was produced with cogeneration. In the same year district heating produced 12.3 TWh of cogenerated electricity. The most common fuels for district heat and CHP were coal (25 %), natural gas (22 %), forest wood (17 %) and peat (14 %) [1].

District heat is economical especially in dense urban areas and the market share can even exceed 90 % in the largest Finnish cities [2]. Report by [3] predicts that district heating will have an important role also in the future and it will continue to be a competitive form of heating. Yet, energy systems are expected to change and e.g. more flexibility is needed. For example, increasing share of variable power generation will cause more fluctuations in the price of electricity. CHP plants generate both heat and electricity, and are therefore affected by more variable electricity prices. Sometimes heat demand and electricity prices are not well paired from the perspective of CHP units. This can be partially mitigated with heat storages.

A study on Finnish future energy system with large amounts of CHP and wind power show that the optimal storage size can be from the current 0.3 % to even 30 % of the annual heat demand [4]. Modelling and optimization of CHP based DH system with high share of RES indicate that both heat demand and power price affect the operation of thermal energy storage and that the storage is used more intensively with a more fluctuating CHP load and higher share of RES [5]. The optimal designs of a CHP plant and thermal energy storage with fluctuating electricity prices have been studied for example by [6] [7] [8]. Fragaki et al. [8] found that in the UK, the use of thermal store can double the plant's return on investment. Higher variations in electricity prices provide an incentive for CHP plant with thermal store [6].

The competitiveness of integrating large-scale heat pump in the DH system of Greater Copenhagen has been studied by Bach et al. [9] and their results show that especially connecting heat pumps in distribution networks is beneficial. Blarke and Lund [10] have studied the financial feasibility of heat pumps integrated with existing CHP plants and their analysis shows that a large-scale heat pump (50 – 60 % of CHP unit's capacity) can even replace the CHP unit as a more financially feasible production unit. Münster et al. [11] found that heat pumps play an important role especially in individual heat production in the future.

In this paper, we analyze the economically optimal capacity of heat storages in three future electricity price scenarios for the DH system of Järvenpää and Tuusula. In addition, the optimal dimensioning of heat pump and solar heat collector, and their impacts on the operation of power and heating plants are also studied. The studied DH system and the model used in the simulations are described in Section 2 and the data used in Section 3. Results are presented in Section 4 and concluding remarks and discussion are given in Section 5.

2 District heating in Järvenpää and Tuusula

We simulate the operation of a DH network in the city of Järvenpää which is connected to the DH of network of Tuusula. There are around 40,000 inhabitants in Järvenpää and around 38,000 inhabitants in the municipality of Tuusula i.e. altogether 78,000 people live in the studied area. In 2014, there were in total 1,280 district heating customers and the net production of electricity with CHP production was 85 GWh [1].

The DH system used in the simulations is described in Table 1 and the assumed costs and properties of heat production units can be found in Table 2. It is assumed that the outgoing water temperature is 80 °C and the return water temperature is 40 °C, and that these temperatures remain constant. In reality DH temperatures are the higher, the colder the weather is, but the error due to this is small in this kind of study. Real weather data of the area in 2014 - 2015 was used in the simulations. Outside temperature ranges from -20 °C to 30 °C (average 7.8 °C) [12].

The efficiency of the CHP plant is calculated, as usual, based on the lower heating value of the input fuel. That does not take condensing of vapor in flue gases into consideration. Yet, flue gas scrubber is used in the studied CHP plant and as it condenses vapor in flue gas to water, heat recovered can exceed the lower heating value and the efficiency of the plant be greater than 100 %. The high moisture content of wood fuels compared to that in fossil fuels increases the effect of scrubber and further its impact on efficiency. The studied CHP plant is a typical new small plant except the power-to-heat-ratio without scrubber is quite good relative to the plant size. Also a scrubber is rather unusual in this kind of plant in Finland.

Table 1: Heat production units and their properties [1].

Plant	Heat output (MW)	Electricity output (MW)	Main fuel
Järvenpään voimalaitos, CHP	63 (45 + 18)[1]	22	Wood fuel
Järvenpään lämpölaitos, HOB	40		Natural gas
Kaskitie, HOB	24		Heavy fuel oil
Ristinummi, HOB	45		Natural gas
Tuusulan lämpölaitos, HOB	15		Natural gas
Sulan lämpökeskus, HOB	15		Natural gas
Kellokoski, HOB	9		Natural gas
Lahela, HOB	2.5		Natural gas
Bio-HOB	18		Biomass/waste

Table 2: Assumed costs and properties of the HOBs and CHP plant.

		HOB	CHP plant
Costs	Start-up cost	0 €	2,500 €
	Variable operation and maintenance cost	5 €/MWh_{heat}	4 €/$MWh_{electricity}$
Other properties	Total efficiency	85 %	110 %
	Allowed load, of full capacity	0 – 100 %	40 – 100 %
	Minimum operation hours	No minimum operation hours	One week (168 hours)
	Starting up period	1 hour	4 hours
	Shutting down period	1 hour	4 hours
	Annual maintenance period	Bio-HOB: 1.12. - 28.2.	July
	Heat rejection (auxiliary DH cooler)	Not possible/needed	Can be used when electricity price is high

Simulations presented in this paper have been done using energyPRO software [13] that solves the optimal DH operation strategy by minimizing the total variable costs (including revenues from electricity sales) so that heat demand is met. We have used hourly resolution but also other time steps could be used in the software. EnergyPRO is an input/output model and inputs are e.g. hourly heat demand, electricity and fuel prices and capacities of the heat production plants.

3 Data and assumptions

3.1 Hourly heat demand

The hourly heat demand used in the simulations is presented in Figure 1, which shows significant variation in heat demand during the year. The average heat demand in winter is about 4 times higher than in the summer. The total annual heat demand is approximately 370 GWh.

[1] Flue gas condensation is used in the CHP plant and it is assumed in the simulations that it increases the heat output by 18 MW.

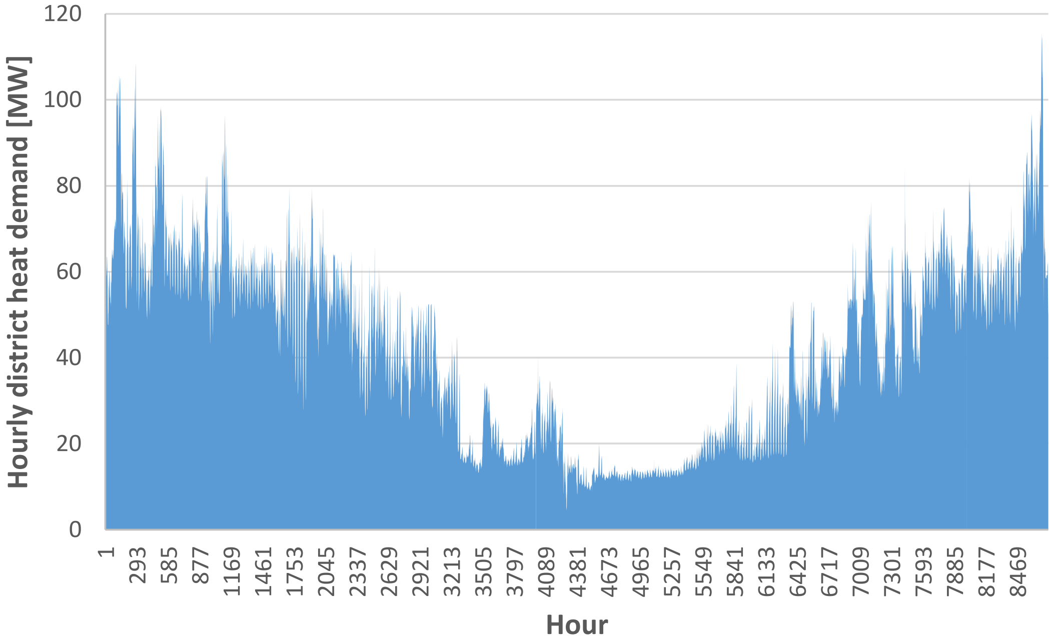


Figure 1: Hourly heat demand used in the simulations.

3.2 Electricity price scenarios

As explained earlier, increased share of RES increases variability in electricity prices which in turn influences the optimal heat production strategy of the CHP unit. We analyse three future electricity price scenarios with different shares of wind power and PV. In the scenario 1, the share of wind power and PV in 2050 is 40 %. In scenarios 2 and 3, the share of wind power and PV is 60 % but in the scenario 3 the share of PV is higher than in scenario 2. Electricity prices of the scenarios are presented in Figure 2 and the average electricity prices in Table 3.

Table 3: Shares of wind power and PV in the studied electricity price scenarios. Average electricity prices are also shown.

Electricity price scenario	Share of wind power [%]	Share of PV [%]	Average electricity price [€/MWh]
1	28	12	70
2	42	18	63
3	30	30	66

The electricity prices have been calculated with a unit commitment and dispatch model WILMAR [14], which in turn has been setup for a future year using a generation planning model Balmorel [15]. Both models operate at hourly resolution, although the generation planning model uses a reduced set of time periods (algorithmically selected three weeks). The base year for the model runs has been different than the weather data base year used by the energyPRO model. Consequently the results are only indicative.

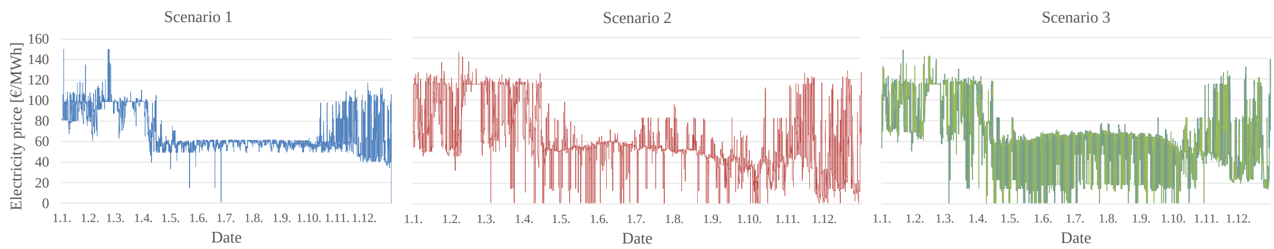


Figure 2: Electricity price scenarios used in this study.

3.3 Costs

The optimization takes into account fuel costs, other variable costs and revenues from electricity sales. These determine the optimal heat production schedule. Fuel prices, taxes and subsidies used in the simulations are shown in Table 4. In Finland, fuels used in heat production in HOBs are subject to a tax. In CHP plants 90 % of the amount of produced heat conducted into the network is subject to the tax. Similar to condensing power plants, electricity production in CHP units is not taxed. In the analysed case the fuel used in the CHP plant is forest chips, which does not have a fuel tax. The model includes the subsidy received by electricity produced with forest chips [16] which thus increases the income from electricity generated by the CHP plant.

Table 4: Fuel prices (incl. CO_2 price, taxes and subsidies used in the model; VAT is excluded) [17] [18] [19] [20] [16].[2]

Natural gas price	27.5 €/MWh
Natural gas tax	17.4 €/MWh
Heavy fuel oil price	35 €/MWh
Heavy fuel oil tax	22 €/MWh
Forest chips price	21.5 €/MWh
Biomass price	35 €/MWh
Electricity distribution cost	21 €/MWh
Electricity tax	22.5 €/MWh
Subsidy for electricity produced with forest chips	18 €/MWh_e

Heat and electricity production is determined based on the total variable costs, i.e. merit order optimisation, but installation of components like heat storages requires investment costs which will be taken into consideration in the profitability calculations. We have estimated the investment costs used in this study based on literature [21] [22] [10] [23] [4] [24] [25] and expert opinions. It should, however, be noted that for example the investment cost of heat pump depends strongly e.g. on the size of the unit and the source of heat. The investment cost of heat storage is influenced for example by the volume and the type of the storage. The additional cost per volume typically decreases as the storage volume increases [26]. In other studies, it is estimated that this variable part of the cost is 33 €/m^3 [4] [24] and 28 €/m^3 [25]. The investment annuity for each component has been calculated using an interest rate of 5 % and a lifetime of 20 years. Different capacities are tested for heat storages, heat pumps and solar collectors. The system components, their properties and the tested ranges for their capacities are described in Table 5.

[2] In this paper, we have especially focused on analyzing how the existing Finnish DH system would adjust to changes in electricity prices. We have used current national fuel prices, taxes and subsidies when the operation of this local DH system was simulated. On the other hand, future electricity prices used in this study were determined for North European market area based on e.g. IEA's New Policies assumptions about fuel and CO_2 prices. Electricity prices are not only dependent on the national situation but also for example on electricity production in other countries and development of electricity transmission connections between countries which were also taken into consideration.

Table 5: Assumed properties and costs of the studied components [21] [22] [10] [23] [4] [24] [25].

		Heat storage	Heat pump	Solar collector
Costs	Fuel price	N.A.	Electricity spot price + distribution cost or subsidy for electricity produced with forest chips[3]	N.A.
	Variable operation and maintenance cost	0	5 €/MWh_{heat}	1 €/MWh_{heat}
	Investment cost	33 €/m^3 * volume (m^3) + 400,000 €	300 €/kW	200 €/m^2
Other properties	Tested capacities	0 – 4,170 MWh (Volume: 0 – 120,000 m^3)	0 – 60 MW (COP = 3.7)	0 – 70 MW (Area: 0 – 100,000 m^2)[4]

4 Results

In this Section, the impacts of different system components are first investigated separately to find economically optimal capacities. In particular, section 4.2 investigates the optimal dimensioning of the heat storage. Finally, the dispatch of the units is analyzed for all the time periods in order to find an optimal combination of heat storage and other components.

4.1 Optimal capacities of heat storage, heat pump and solar heat

The average annual costs of produced heat in different electricity price scenarios are illustrated in the Figure 3. All variable costs, income from electricity production and investment annuities are taken into consideration in these costs. As can be seen from Figure 3, costs for heat storage are decreasing until approximately 80,000 – 100,000 m^3. Yet, a small heat storage (10,000 – 60,000 m^3) is not profitable as the costs are then higher with a heat storage than without one (0 m^3 on the left edge of the figure). On the other hand, larger heat storages are economical and the optimal storage volume is around 100,000 m^3. Figure 3 also shows that there is no significant decrease in the costs when a heat pump is included in the DH system but a heat pump of around 20 – 25 MW seems the most economical investment. According to the results, solar collector is not a profitable investment given the cost assumptions and the Northern latitude of the DH system.

[3] We have assumed that the operation of heat pump is independent of other units (CHP plant) in the optimization and heat pump included in the DH system can use electricity produced in CHP plant or bought from electricity market. As heat pump is in the DH network, electricity tax does not need to be paid for the consumed electricity [27]. Yet, if heat pump uses electricity from CHP plant, this electricity cannot be sold (i.e. no revenues from electricity selling) or benefit from the subsidy. On the other hand, if electricity is bought from the market, distribution cost have to be paid. As subsidy and distribution cost are approximately of the same amount, we have assumed that the cost of electricity used in heat pump is a sum of electricity price and distribution cost.

[4] We assume that the relation between solar collector area and capacity is 1 m^2 = 0.7 kW_{th} [28].

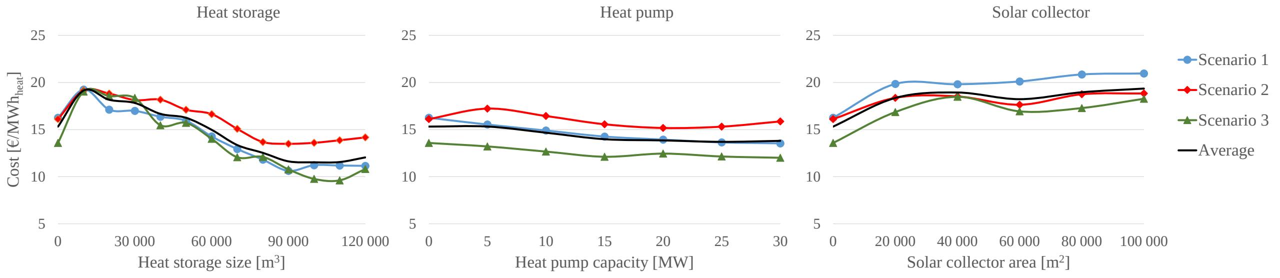


Figure 3: Average annual cost for one produced MWh of heat in different electricity price scenarios. Average of these scenarios is also shown. Costs include variable costs, revenues from electricity sales and the annuity of the heat storage, heat pump or solar collector investment. CHP plant or DH network investment is not included. It should be noted that the vertical axis is from 5 €/MWh$_{heat}$ to 25 €/MWh$_{heat}$.

4.2 Heat storage with and without heat pump

As found earlier (Fig. 3), when components are studied separately, the most economical size for the heat pump is 20 – 25 MW and for the heat storage around 100,000 m^3. In order to find the optimal capacity of heat storage with a heat pump of 20 MW in the DH system, costs at different levels of heat storage volume were calculated. Results are presented in Figure 4 and as can be seen, a heat storage of approximately 110,000 m^3 seems optimal also with a heat pump in the DH system. When DH system includes both the heat storage and the heat pump (Fig. 4), the costs are slightly lower than when these components were studied separately (Fig. 3).

Results also show that the average heat production costs are highest in the scenario 2 where the average electricity price is lowest. Heat production costs are typically lower in the scenario 3 than in the scenario 1 even though the average electricity price is higher in the scenario 1. Electricity price varies stronger in the scenario 3 which is why electricity sales can be more profitable.

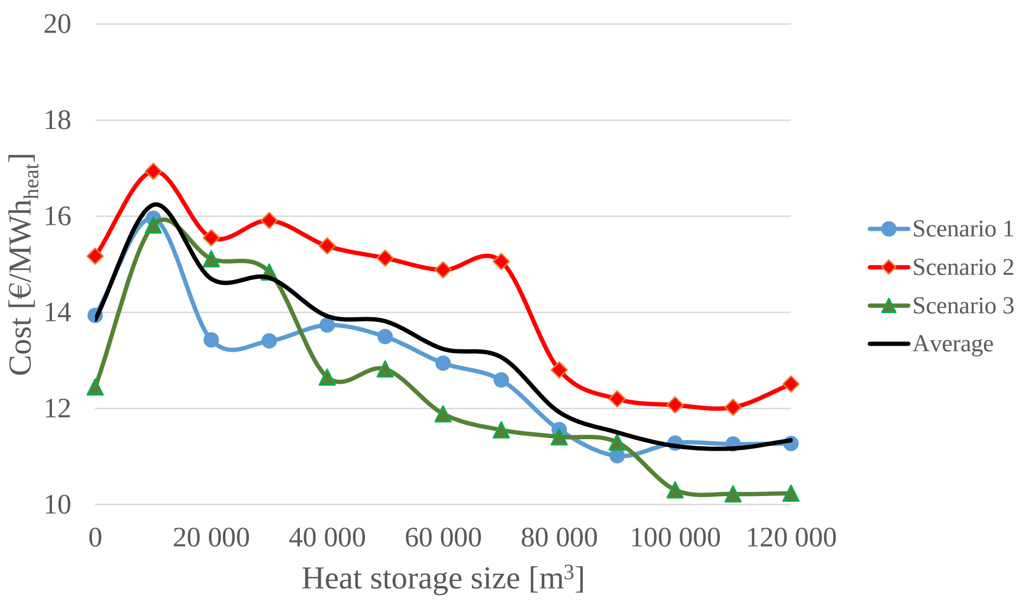


Figure 4: Average annual cost for one produced MWh of heat in different electricity price scenarios when a heat pump (20 MW) is included in the DH system. Average of the three electricity price scenarios is also shown. Costs include variable costs, revenues from electricity sales and annuities of heat pump and heat storage investments. It should be noted that the vertical axis is from 10 €/MWh$_{heat}$ to 20 €/MWh$_{heat}$.

4.2.1 Electricity production

In Table 6, the electricity production and number of CHP unit start-ups are presented with and without the 20 MW heat pump. When the heat pump is included, the electricity consumption of the heat pump is also shown. A heat storage of 110,000 m^3 is included in all cases in Table 6. Electricity production and number of CHP unit start-ups with and without the heat storage or the heat pump are presented in Table 7.

Table 6: Electricity production, number of starts of CHP plant and electricity consumption in heat pump. A heat storage of 110,000 m^3 is included in all cases.

Electricity price scenario	Heat pump (20 MW)	Electricity consumption in heat pump [GWh/year]	Gross electricity generation [GWh/year]	Revenues from selling electricity [M€/year]	Number of CHP start-ups
1	Excl.		97	7.3	17
1	Incl.	16	92	6.8	18
2	Excl.		91	6.5	15
2	Incl.	21	86	6.2	16
3	Excl.		103	7.6	13
3	Incl.	17	95	7.0	15

It can be seen from Table 6 that a heat pump in the DH system decreases the electricity produced by the CHP unit but increases the start-ups of the CHP unit in all of the electricity price scenarios. The revenues from electricity sales are highest in the scenario 3. Heat pump is used more in the scenario 2 than in other scenarios. When the results from Tables 6 and 7 are compared, it can be seen CHP unit has less start-ups when there is no heat storage in the DH system. In the scenarios 1 and 3, the produced electricity and revenues from electricity sales are lower when there is no heat storage in the DH system.

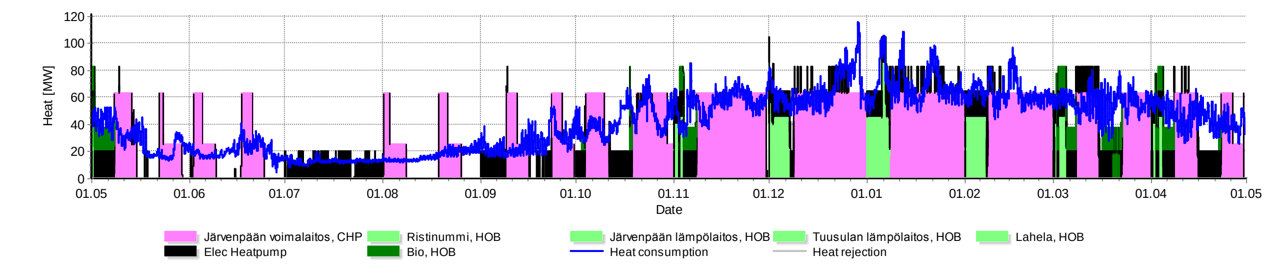
Table 7: Electricity production, number of starts of CHP plant and revenues from electricity sales when DH system does not include heat storage or heat pump.

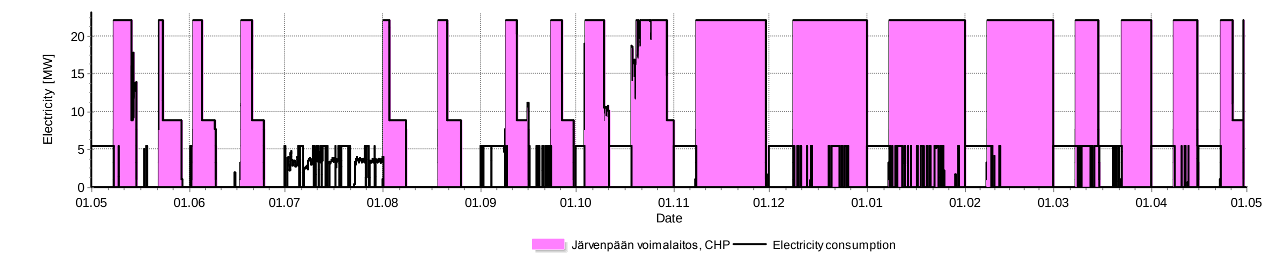
Electricity price scenario	Gross electricity generation [GWh/year]	Revenues from selling electricity [M€/year]	Number of starts, CHP
1	78	6.1	10
2	94	6.6	12
3	103	7.4	12

4.2.2 Heat and electricity production profiles

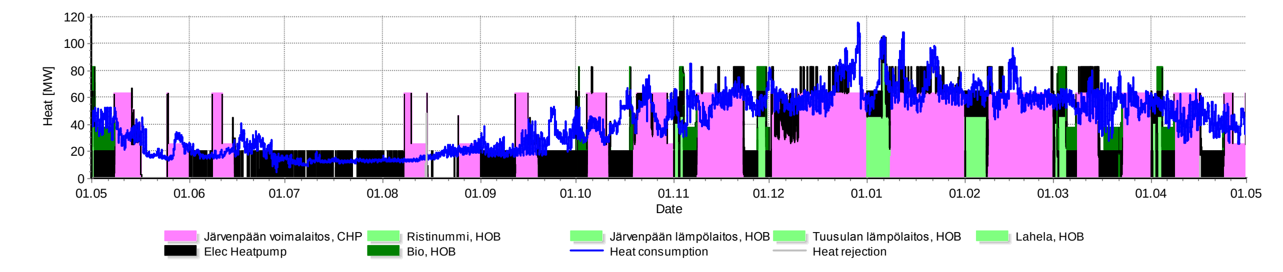
The heat and electricity production profiles during a whole year are presented in Figure 5. The case includes a heat storage (110,000 m^3) and a heat pump (20 MW). The appendix (Figure A.1) contains a more detailed look on the profiles for July and January. Figures demonstrate that the CHP plant is run especially in winter when both heat demand and electricity prices are high. It can also be seen that in July (Fig. A.1) the heat demand is fully covered with the heat pump in all electricity price scenarios. However, it should be noted that in July the CHP unit is on maintenance and cannot be used which can influence the results.

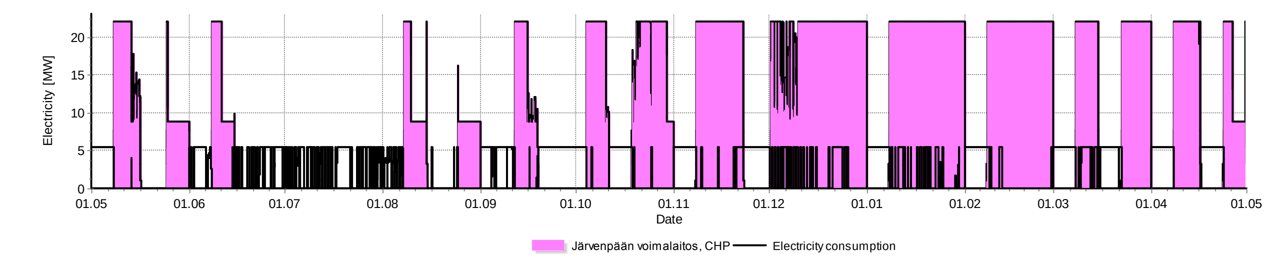
Scenario 1



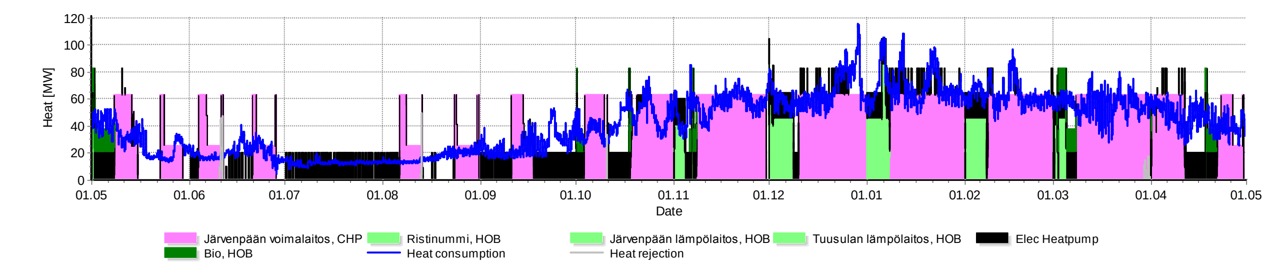


Scenario 2:





Scenario 3:



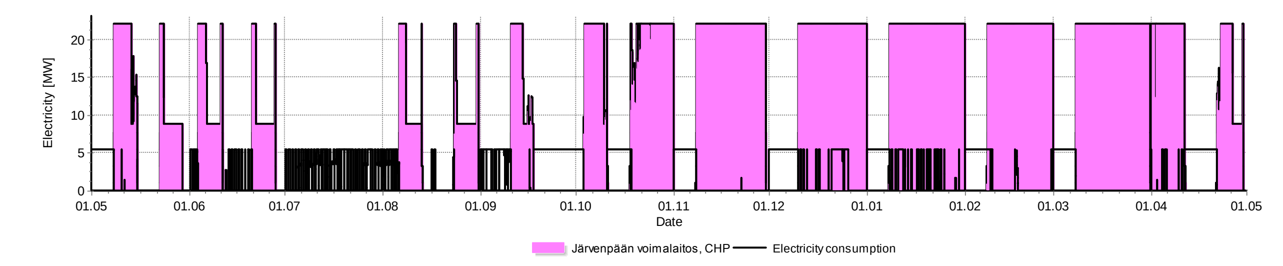
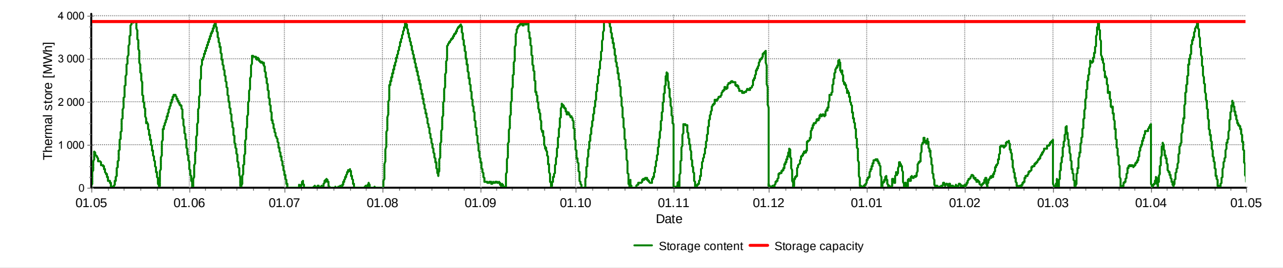


Figure 5: Heat and electricity production and consumption during one whole year (starting from May) in the studied electricity prices scenarios.

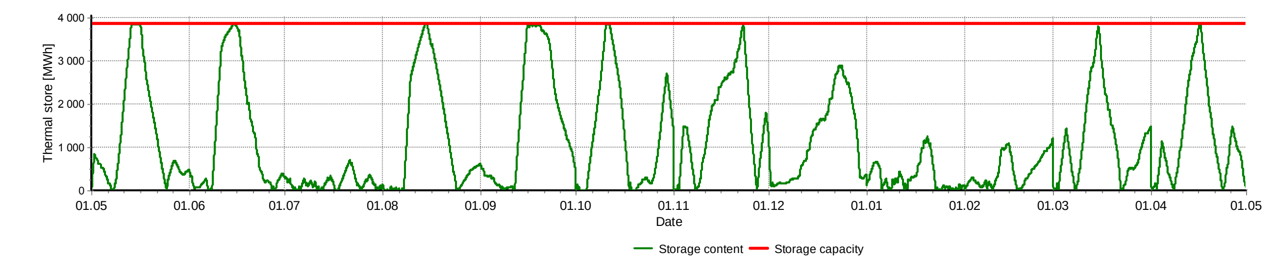
4.2.3 Heat storage content

Heat storage can be used to balance the timing between heat production and demand. As the CHP unit does not operate based on heat demand alone, but also on electricity prices, the heat storage can be particularly useful when the electricity prices are more volatile. Figure 6 shows the heat storage content during a whole year with a heat storage (110,000 m^3) and a heat pump (20 MW) in the DH system.

Scenario 1:



Scenario 2:



Scenario 3:

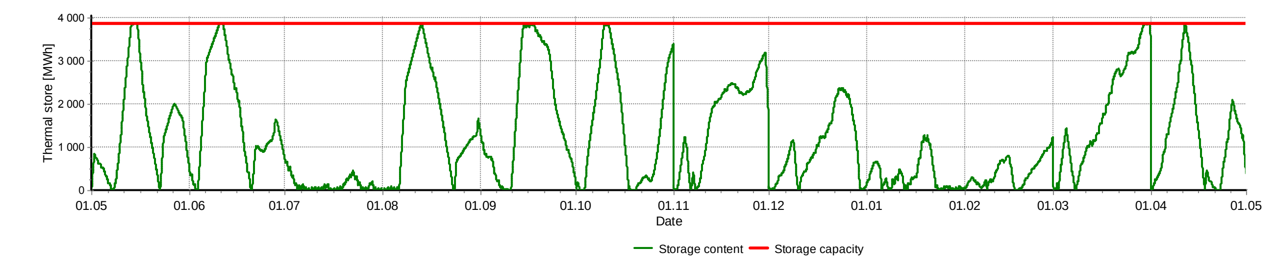


Figure 6: Heat storage content in different electricity price scenarios.

Fig. 6 shows that the charging and discharging of storage is scheduled alike in scenarios 2 and 3 – the storage content is highest at the same moment in all scenarios. In scenario 1, with highest average electricity prices, the heat storage is charged more often. In addition, the storage content is lowest from mid-June to early August and from December to March in all scenarios. In summer, the heat demand is low and only the heat pump is utilized (Fig. 5) and in winter with high heat demand the heat storage is not charged.

5 Discussion and conclusions

In this paper, we studied the effects of a heat storage in a DH system located in the Southern Finland. In particular, the economically optimal dimensioning of the heat storage in three future electricity price scenarios with high shares of renewable energy was analyzed. Also the role and profitability of heat pumps and solar collectors were investigated.

The results indicate that in the studied DH system, a small heat storage (10,000 – 60,000 m^3) is not a profitable investment but a larger heat storage (100,000 – 110,000 m^3) is economical. This slightly surprising result may arise from the quite high base investment cost and low marginal volume unit cost increase that was assumed. This assumption is to be explored in the future especially since this result contradicts some other studies and practical experiences from Finland where especially small heat storages are usually found to be profitable. While this may be due to the more volatile power prices in the study, the results indicate that a large heat storage helps the CHP unit to produce more electricity and increase revenues.

Another finding of the study was that a larger heat pump was more profitable than a small heat pump. The optimal heat pump size converged around 20 – 25 MW. Still, the least cost solution was to combine a heat storage and a heat pump. With our assumptions, solar collector was not a profitable investment.

The results show that the costs for producing the heat for the DH system were lowest in the scenario 3 where the share of PV is high and there is a larger variation in the electricity price. When a heat storage is included in the system, the CHP unit start-ups is lowest in the scenario 3 and the CHP unit produces more electricity than in other scenarios. Scenario 2 has usually the highest heat production costs while it also had the highest variation in the electricity prices. This was more than compensated by the lowest average electricity prices amongst the scenarios as the lower average prices resulted in lower revenue.

The scope of the paper was limited to the potential DH system components (heat storages, heat pumps and solar collectors), but other factors could influence the way in which heat demand should be balanced. For example the impacts of demand side management could be studied in future research. Sensitivity of the results should be studied, especially in considering variations in fuel prices, investment costs, minimum operation times of the plant and heat demand. Some changes in these have been explored, even though not reported in this paper, and the impact can even be highly influential, which underlines the need continue the studies. In addition, changes in fuel taxation and subsidies could be taken into consideration. Finally, the time series for the district heating system and electricity prices need to be aligned to improve the validity of the results.

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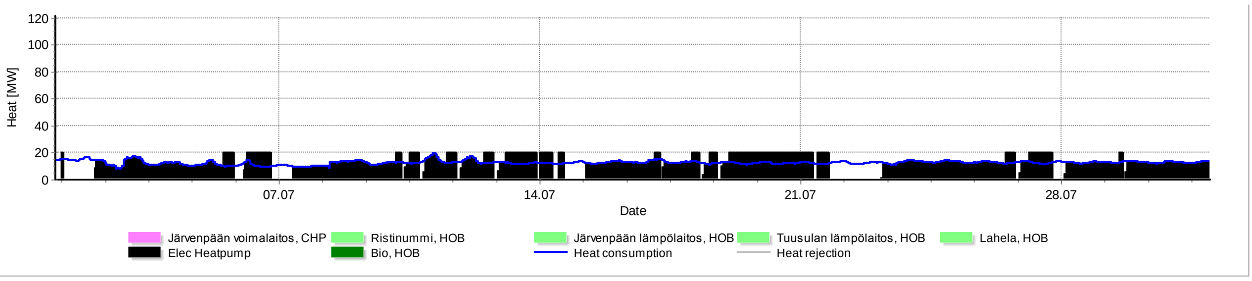
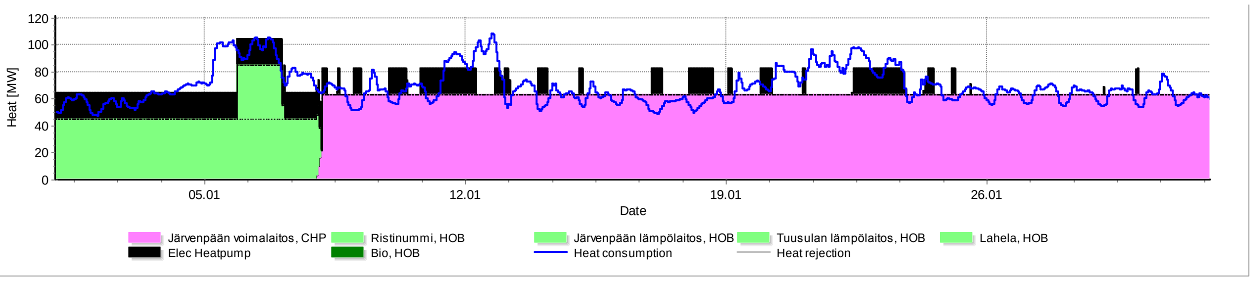
Appendix A

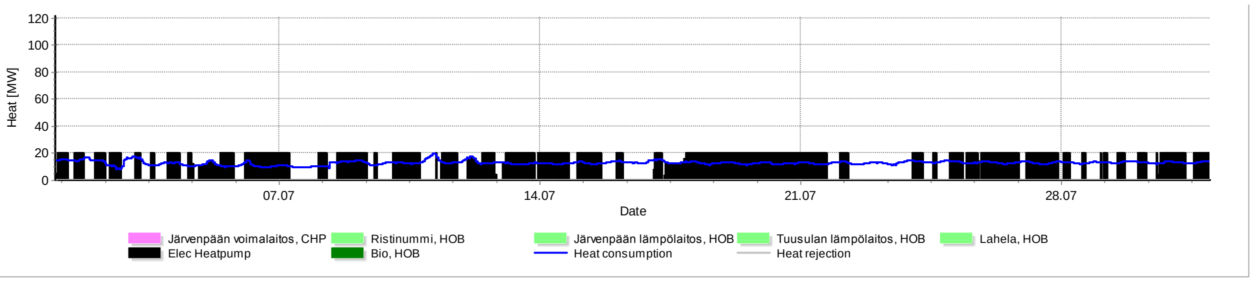
Scenario 1, July:



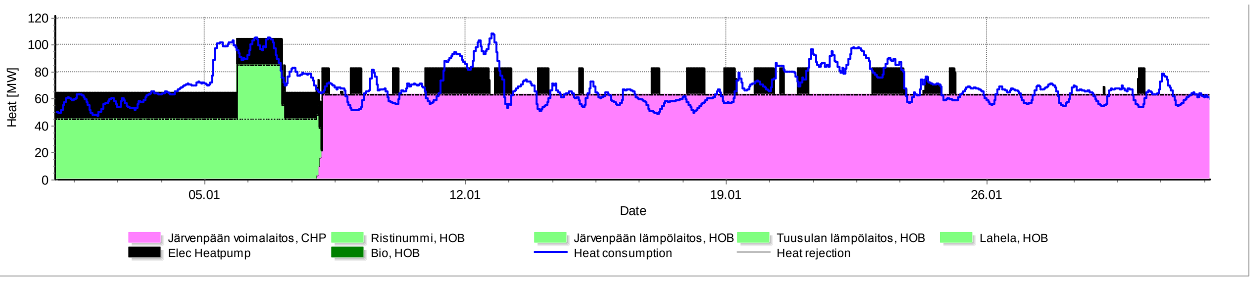
Scenario 1, January:



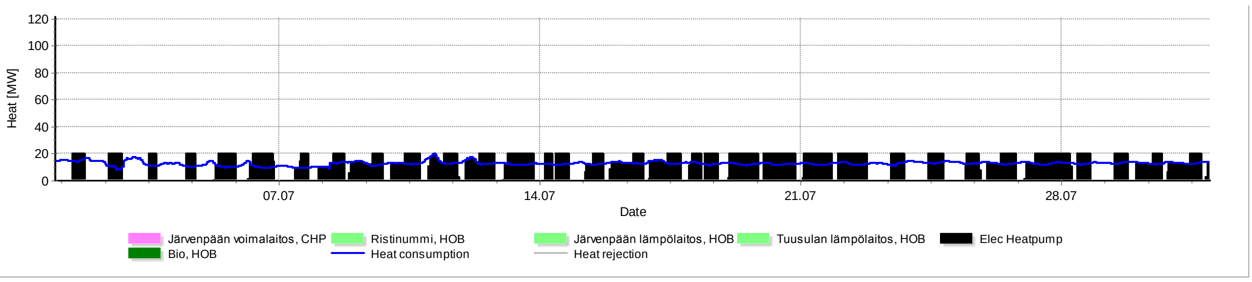
Scenario 2, July:



Scenario 2, January:



Scenario 3, July:



Scenario 3, January:

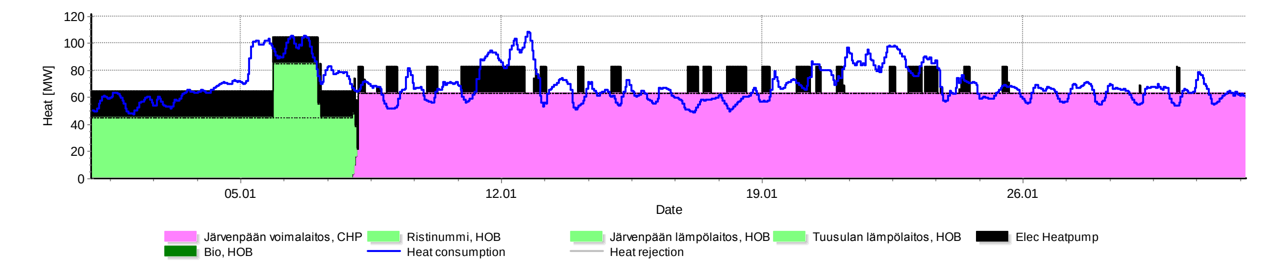


Figure A.1: Heat production and consumption in July and January in the studied electricity price scenarios. Heat pump (20 MW) and heat storage (110,000 m^3) are included in the DH system.