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Coupling of the electricity and district heat generation sectors with building stock energy retrofits as a measure to reduce carbon emissions

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ABSTRACT

This study examined how the carbon dioxide emissions can be reduced in an energy system with coupling of the electricity and district heat generations, while considering different paths for the building stock development. As the building sector and the energy sector are interdependent on one another, it is important to consider them as a whole, to understand to what extent emission mitigation measures should be conducted in each of them, to avoid unnecessary costs. The problem was applied to a Finnish context and formed as a mixed-integer linear programming problem, which was used to minimize the emissions from highly renewable electricity and district heat generations, by using the flexible properties in both. A scenario-based analysis was performed, where simulations were conducted for the year 2050 and the effects to the emissions and energy system costs were examined over 30 years up to 2050. The set target of 90 % emission reductions in annual emissions, from the 2020 level, was attained with several combinations of wind power, deep heat well heat pumps, and thermal storage as part of the energy generation, for each of the energy retrofit scenarios of the building stock. However, both the building stock and energy system measures were required to reach the target. The amount of wind power had a major impact on the results, and in general the more wind power was utilized the less the other measures were required. Moreover, when the building stock was retrofitted to a lower environmental impact level, the costs to reach the target emissions were less than half compared to retrofitting them to a higher impact level. However, there was no major difference whether the building stock developed more towards household heat pumps or district heating. The least costly set of options to reach the target emissions for 2050, 1.83 Mt of carbon dioxide annually, attained them with a cost increase of 10.18 billion euros from the reference over 30 years. The emissions for the same period decreased by 56 %, from 488 to 217 Mt of carbon dioxide, resulting in a unit cost of 37.6 € per ton of carbon dioxide for the emission reductions.

1. Introduction

Decarbonization of the energy systems according to the goals of the Paris Climate Agreement from 2015 will require reducing greenhouse gas emission in all sectors of the society [1]. For example, the goal of the European Union (EU) to become carbon neutral by 2050, demands for practically eliminating all emissions in the power, heating, and transport sectors [1]. As around half of all final energy use originates from heating and cooling, these sectors often play a key role in the national efforts to

Abbreviations: BHE, Borehole heat exchanger; BAU, Business-as-usual; CCGT, Combined cycle gas turbine; CHP, Combined heat and power; COP, Coefficient of performance; CO_2, Carbon dioxide; DH, District heating; DHWHP, Deep heat well heat pump; Elec, Electricity; EU, European Union; ETS, Emission trading system; HP, Heat pump; LCOE, Levelized cost of electricity; LCODH, Levelized cost of district heat; MILP, Mixed-integer linear programming; O&M, Operation and maintenance; PtH, Power-to-heat; PtX, Power-to-X; PV, Photovoltaic; ROR, Run-of-river; SOC, State of charge; TS, Thermal storage; T&D, Transmission and distribution; VRE, Variable renewable electricity.

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Nomenclature

Indices

i iteration
t time index

Parameters

$C_{total,2021}$ Total costs of the energy system measures and the building stock in 2021 (€)
$D_{t,i}^{DH}$ Total district heating heat demand (MWh/h)
$D_{t,i}^{elec}$ Total electricity demand (MWh/h)
$D_{t,i}^{elec\ buildings}$ Electricity demand of building stock (MWh/h)
$D_{t,i}^{elec\ DH}$ Electricity demand of district heating (MWh/h)
$D_{t,i}^{elec\ DH,0}$ Electricity demand of district heating, starting value (MWh/h)
$D_{t,i}^{elec\ Finland}$ Electricity demand in Finland without building stock (MWh/h)
EF^{CCGT} Emission factor for CCGT (kg-CO_2/MWh)
EF^{FB} Emission factor for fossil heat boiler (kg-CO_2/MWh)
$EM_{t,i}^{elec,opt}$ Electricity mismatch, before CCGT generation, after electricity generation optimization (MWh/h)
$Inflow_{t,i}^{hydro}$ Hydro inflow for flexible hydro power (MWh/h)
$P_t^{EB,0}$ Power consumption of electric boilers direct heat to DH, starting value (MWh/h)
$P_{t,i}^{EB,max}$ Maximum limit for electric boilers, direct heat to DH and charging of thermal storage (MWh/h)
$P_{t,i}^{fixed}$ Fixed electricity generation: Nuclear, CHP industry, ROR hydro, and wind power (MWh/h)
$P_t^{HP,0}$ Power consumption of HPs, starting value (MWh/h)
$P^{hydro\ flex,\ max}$, $P^{hydro\ flex,\ min}$ Maximum and minimum limits for flexible hydro generation (MWh/h)
$P_t^{TS,\ ch,0}$ Power consumption of charging of thermal storage, starting value (MWh/h)
$Q_t^{HP,max}$, $Q_t^{HP,min}$ Maximum and minimum limit for heat pump generation (MWh/h)
$SOC^{hydro,max}$ Maximum limit for aggregated hydro storage (MWh)
$SOC^{TS,max}$ Maximum limit for thermal storage (MWh)
$SOC_{t,i}^{TS,0}$ Thermal storage state of charge starting value (MWh)
T Hours of one year = 8760
$T_{DH\ supply}$ DH network supply temperature (°C)
$T_{dimensioning}$ Dimensioning temperature for housing (°C)
$T_{outdoor}$ Outdoor air temperature (°C)
η^{EB} Efficiency for electric boiler (%)
$\eta^{TS,\ hourly}$ Hourly efficiency for thermal storage (%)
$\eta^{TS,\ ch}$, $\eta^{TS,\ dch}$ Efficiency of charging and discharging of thermal storage (%)

Variables

$B1_{t,i}$ Binary variable for discharging of thermal storage
$B2_{t,i}$ Binary variable for charging of thermal storage
$EM_{t,i}^{DH,\ opt}$ Electricity mismatch, after DH optimization (MWh/h)
$P_{t,i}^{CCGT}$ CCGT generation (MWh/h)
$P_{t,i}^{EB}$ Electric power of electric boilers, for direct heat to DH (MWh/h)
$P_{t,i}^{HP}$ Electric power of heat pumps (MWh/h)
$P_{t,i}^{hydro\ flex}$ Flexible hydro generation (MWh/h)
$P_{t,i}^{TS,\ ch}$ Charging power of thermal storage (MWh/h)
$P_{t,i}^{underproduction}$ Electricity deficit, after DH optimization (MWh/h)
$Q_{t,i}^{FB}$ Heat generation from fossil boiler (MWh/h)
$Q_{t,i}^{HP}$ Heat generation from heat pumps (MWh/h)
$Q_{t,i}^{TS,dch}$ Discharged heat from thermal storage (MWh/h)
$SOC_{t,i}^{hydro}$ State of charge of aggregated hydro storage (MWh)
$SOC_{t,i}^{TS}$ State of charge of thermal storage (MWh)

reduce emissions [2].

According to the IPCC 2021 report, the 1.5-degree limit under the Paris Agreement is expected to be exceeded by the early 2030 s, 10 years earlier than previously estimated. According to the report, achieving carbon neutrality requires not only emission reductions but for example carbon sequestration in forests and soils too [3]. Thus, new non-combustion technologies are needed for both the electricity and heating sectors.

Another motivation for low emissions is the current price development of carbon dioxide (CO_2) emissions. For example, the price in the EU Emission Trading System (ETS) doubled in 2021, and at the end of 2021 was already around 80 €/t-CO_2 [4].

Electrification will be one key strategy to reduce emissions, mainly due to the rapid market penetration of solar and wind power. The International Energy Agency estimates that these could generate close to 70 % of all electricity globally by 2050 [5]. However, incorporating high amounts of variable renewable electricity (VRE) in power systems will increase the mismatch between the power supply and demand, which will require additional flexibility in the system [6]. Through sector coupling between electricity and heating, or some other power-to-X (PtX) conversion, the mismatch challenge could be mitigated, while also decarbonizing the sectors through increased use of carbon-free electricity, e.g., in case of the heating sector using heat pumps with power-to-heat (PtH) to substitute fossil fuels. This coupling of the power and heating sectors was studied in [7], where it was identified as an important strategy for mitigating emissions.

Studies which couple the heating with the power sector often employ renewable electricity and thermal storage for more optimal operation of the energy system. For example, in [8] the coupled power and heating sectors were examined, and it was found that increasing the thermal storage size increased the use of variable renewable electricity generation. Moreover, in [9] the PtH sector coupling was analyzed to maximize the VRE use in the energy system. Through PtH, the self-use share of wind power could notably be increased. In addition, linking district heating (DH), which is a typical heating system in some northern cities, with PtH has been analyzed from different aspects, e.g., what kind of role it has to climate mitigation and economic growth [10], to sustainability in energy systems [11], or in large scale energy systems [12]. DH is often supplied through co-generation schemes, which makes PtH with e.g., wind power sometimes more challenging, as also the co-generation system may be affected. Mikkola et al. [13] showed that in many cases using PtH and VRE with heat pumps would be more beneficial, as energy use in cities is heat dominated.

For wide utilization of PtH with heat pumps in an energy system, a large heat source for the heat pumps is required. One possible solution is to utilize deep heat well systems, which have already been realized world-wide. Wang et al. [14] analyzed three 2 km deep wells connected to a heat pump in China, reporting a very high coefficient of performance (COP) value of 6.4 (4.5 for system COP). Whereas Kohl et al. [15] studied a 2.3 km-deep borehole heat exchanger (BHE) in Switzerland connected to a heat pump for building heating. Lund [16] has simulated a 2-km deep BHE in Finnish geological conditions with different thermal, geological, and hydraulic parameters, verifying the suitability of this technology to Finnish conditions. The temperature of the bedrock varies by geographical location, which means that the bedrock temperatures in Switzerland and China are different from, for example, Finland. Presently, several deep heat well pilot plants are under construction in Finland [17].

Currently more than 40 % (38 TWh) of heating in Finland is based on DH [18], of which around 2/3 is generated through co-generation and 1/3 in separate heating plants. Moreover, 1/3 of the fuels used in DH are fossil based, mainly coal and peat. Therefore, renewable electricity with PtH conversion would be a highly interesting option for the DH sector. In power, CO_2-free nuclear power and renewable energy sources stand for over 80 % of the generation. The growing share of wind power (now 10 %), due to its decreasing price, and two new nuclear power plants, indicate that electricity might reach a zero-emission level around 2030 [19,20]. Thus, electricity in Finland could be an effective way to cut emissions in the heating sector, and in other sectors too, such as transport or industry.

In the previous studies examining the sector coupling of power and heat, different paths for building stock development have not been considered. These can alter the building energy demand, e.g., due to energy efficiency improvements or changes in the heating systems utilized in the buildings. In addition, how the sector coupling of power to heat would affect the power sector dynamics, has often not been considered. Moreover, an integrated view of the flexibility of the heat and power sectors together, instead of separate considerations, seems often to be overlooked. In addition, for large-scale heat pump schemes in PtX it is important to examine the adequacy of the heat source for heat pumps, which is often not defined.

The novelty of this study is considering the sector coupling of the power and district heat sectors together with the different paths for the development of the building stock. That is, to examine to what extent the decarbonization measures should be conducted in the energy sector and to what extent in the building stock, to avoid unnecessary costs when mitigating the combined carbon emissions. The problem was applied to a Finnish context, where recent demand load profiles were used for the building stock, with different retrofit levels from [21]. The sector-coupled power and district heat generations were formed to include high shares of VRE, and their generations were optimized to minimize the CO_2 emissions by using their individual flexibility potentials, with 1-hour resolution. In addition, to realistically address the huge heat source demand for heat pumps foreseen, an emerging, but already full-scale piloted deep heat well system technology was employed, which is well suited for DH schemes [16]. A simulation was done for Finland for the year 2050, and the effects to the emissions and costs were analyzed over 30 years up to 2050. Finland provides an interesting case for carbon mitigation studies as it aims to reach net zero emissions by 2035 [22].

The paper begins by describing the model used for the optimization, together with the electricity and district heat generation sources, and the building stock retrofit scenarios, in Section 2. In Section 3, the results of the simulations are presented with the sensitivity analysis, which are then discussed in Section 4. The conclusions are summarized in Section 5.

2. Methodology

This section presents the system setup used in this study for the problem formulation. In addition, the components included in the setup, i.e., the building stock retrofits and electricity and district heat generation sources, are presented in detail. Moreover, the parameters to determine the economic feasibility of the proposed system are presented in Section 2.6, and the equations used in the optimization are presented in Section 2.7.

2.1. System setup

The schematic of the system setup is presented in Fig. 1. The building retrofit scenarios, presented in detail in Section 2.2, affected both the total electricity and DH demands in the model. The mixed-integer linear programming (MILP) problem consisted of two objective functions, one for electricity generation and one for the generation of district heat. The modeled electricity generation consisted of several sources represented with hourly time series over one year, which remained the same for every simulation: nuclear, combined heat and power (CHP) for industry, and run-of-river (ROR) hydro power. Wind power was also represented with an hourly time series, but it was scaled up to examine 10 different penetration levels for it, representing different installed capacities. Flexible sources were the hydro power connected to reservoirs and combined cycle gas turbine (CCGT) generation using natural gas as a fuel. Electricity import, which covered 22.4 % of the demand in 2015–2019 [23], was not considered, nor was CHP for district heat. The objective function for the electricity generation minimized the CO_2 emission from it, by utilizing the flexibility of hydro power. After solving the objective for the electricity generation, the hourly electricity mismatch i.e., the difference between electricity supply and demand before the CCGT generation, was transferred to the DH generation side of the model.

The district heat modeling consisted of deep heat well heat pumps (DHWHPs), electric boilers, short-term thermal storage, and fossil heat boilers using natural gas as fuel. All of these were flexible in their operation, but with limited power capacities. The objective function for the district heat generation minimized the combined CO_2 emissions from the DH generation and the electricity mismatch, by utilizing the flexibility of the DH generation. For example, during an hour of electricity undergeneration the heat pumps could ramp down, and thus reduce the electricity demand, while the DH demand would be covered with thermal storage, if this resulted in a decrease in the annual emissions. After solving the DH generation objective function, the electricity demand of the DH generation was transferred to the electricity generation side of the model as part of the total electricity demand. This iterative process, solving the objectives for electricity and DH sequentially, was carried out until the relative change in total emissions between two iterations was less than 0.01 %, but at least 10 iterations were always performed.

The concept of using the two objective functions, one for electricity and one for district heating, was to imitate the electricity generators and the district heat generators as separate entities, which would share information with each other and recalculate their generations based on it. By this method they could adjust their generation to the needs of the other party. The electric generator could shift the overgeneration, when possible, to a desired hour by the district heat generator, and the DH generator in return could reduce its electricity demand and thus the undergeneration of the electricity generator, by utilizing the thermal storage if possible. In this study the incentive to do this, for both entities, was to reduce the carbon emissions.

2.2. Building stock retrofits

Hirvonen et al. [21] have previously examined different retrofit scenarios for the Finnish building stock for 2050. These scenarios for the total building stock were based on previous retrofit studies for six different building types: detached houses [24], multi-storey apartment buildings [25], elderly care buildings [26], office buildings [27], educational buildings [28], and retail buildings [29]. In these studies, a large variety of different retrofit options were simulated, and several Pareto optimal solutions achieved for each building type in terms of life cycle costs and CO_2 emissions or primary energy consumption. The different retrofit options available, even though not necessary always implemented, for each building type in the optimizations in the previous studies, are presented in Table 1.

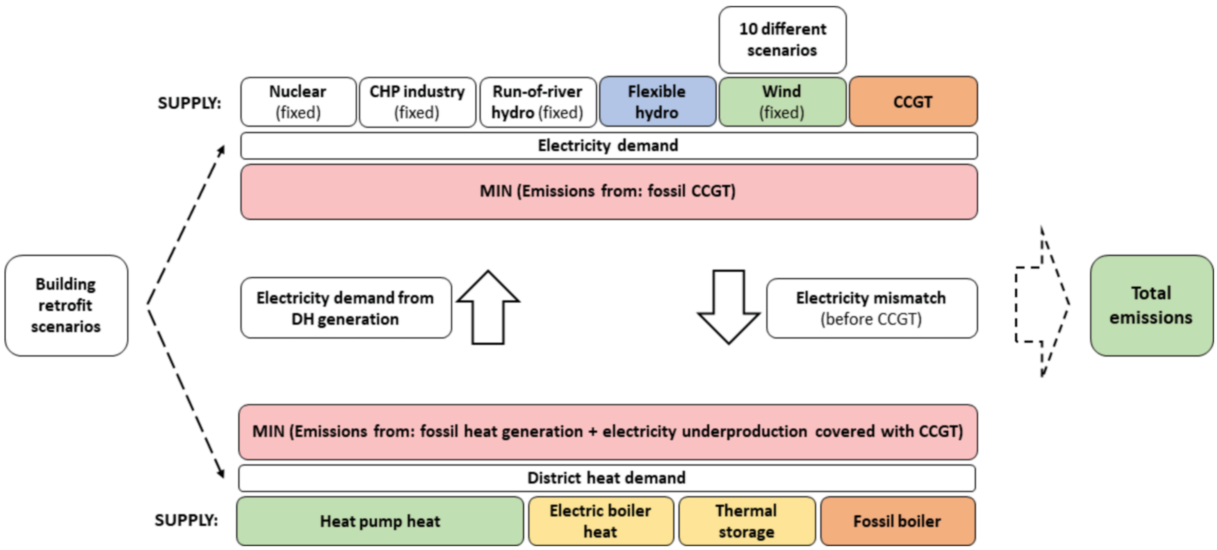

Fig. 1. Schematic of the system setup. Optimization for the electricity generator minimized the emissions of the CCGT generation and transferred the electricity mismatch to the DH generation side of the model, which then minimized the combined emissions from the electricity mismatch and the DH generation. After which, the electricity demand of the DH generation was transferred to the electricity generation side of the model. The problem was solved with iterations until the difference in total emissions between two iterations was less than 0.01 %.

Table 1
Retrofit options for each building type [21].

	Retrofit options for building types					
Retrofit measure	Apartment	Single-family	Elderly	Educational	Office	Retail
Thermal insulation of walls	x	x	x	x	x	
Thermal insulation of roof	x	x	x	x	x	
New doors	x	x				
New windows	x	x	x	x	x	
Blinds between window panels					x	
Mechanical ventilation with heat recovery	x	x	x	x	x	
Variable air volume ventilation	x	x			x	
Sewage heat recovery	x					
Convert oil boiler to wood boiler		x				
Ground source heat pump	x	x		x	x	x
Exhaust air heat pump	x					
Air-to-water heat pump			x			
Air-to-air heat pump		x				
Low temperature radiators	x	x				
Solar thermal	x	x	x			
Solar (PV)	x	x	x	x		x
Energy efficient lighting					x	
Automated lighting control			x		x	

The six building types were used in [21] to construct the Finnish building stock. The respective shares of the floor areas by building type are presented Fig. 2 [30]. The 5.5 % of the built floor area listed as other service building were modeled in [21] as retail and office buildings. 15 % of the built floor area is industrial and warehouse buildings and they were not considered in [21] as they are in statistics considered a part of the manufacturing sector. However, part of these buildings use DH as their main heating system. Thus, in this study also their district heating demand was considered in the total DH demand in Finland in Section 2.4.

Furthermore, in [21] the development of the building stock was modeled from 2020 to 2050, considering the current building stock, the mortality rate of different buildings, population changes, and regional characteristics, based on [31].

Finally, in [21] these measures were used to create a reference scenario for 2020, a business-as-usual (BAU) scenario for 2050, and four retrofit scenarios for 2050 for the total building stock: DH Low, DH High, HP Low, and HP High. The reference scenario for 2020 provided a close approximation of energy consumption in the building stock compared to Finnish statistics. All the 2050 scenarios considered the decreased heating need due to climate change as estimated in [32]. In the BAU scenario the distribution of the heating systems remained the same as in the reference scenario, but the addition of new buildings and building mortality were considered. For the retrofit scenarios most of the buildings were renovated or replaced with new ones and the distribution of the main heating systems changed. In the 'DH' scenarios there was a strong shift towards district heating, and in the 'HP' scenarios a large part of the building stock switched to ground-source HPs or air-to-water HPs installed in the buildings. No oil heating was used in the retrofit scenarios. These changes are presented in Fig. 3a, where all refer to heating systems installed in a building or its premises. In addition, the electric heating refers to direct electric heating in the buildings. The exact shares of the primary heating systems, in each building stock scenario are presented in Table 2. In the 'Low' scenarios the buildings were retrofitted less and cost-neutrally, to a lower, and in the 'High' scenarios more, to a higher environmental impact level. This is displayed in Fig. 3b, where electricity and DH demands for the building stock, as in [21], in each building stock scenario are presented. Notably

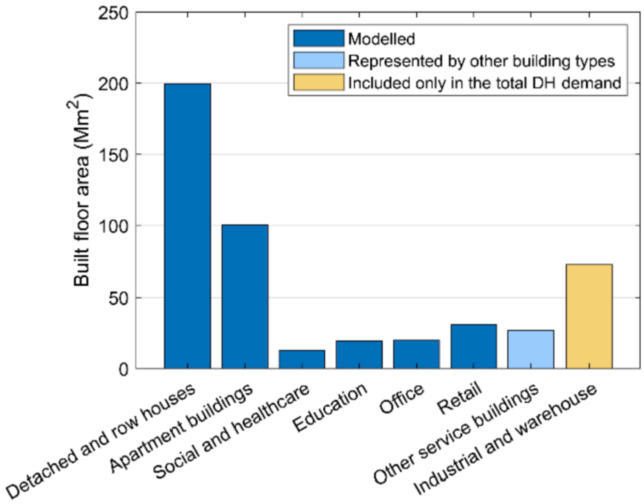

Fig. 2. Built floor area by building type [30].

for the 'HP' scenarios the electricity demand increased compared to the 'DH' scenarios as a larger part of the building stock was assumed to utilize individual heat pumps, but this was compensated by a reduced district heating demand. In addition, the electricity and district heat demands in Fig. 3b are the ones used later as parameters that affected the total electricity and district heating demands in the optimizations of this study.

In this study, only the moderate scenario for rooftop solar photovoltaic (PV) from [21] was considered, where in total 2–3 GW of solar PV capacity was installed. Moreover, the electricity demand of the buildings considered in this study was the 'Elec from grid' from [21], which means the electricity demand remaining after utilization of on-site solar electricity generation.

2.3. Electricity generation sources and demand

The electricity demand was formed from the total electricity demand in Finland in 2019 [33] which was then altered by the change in the electricity demand of the building stock from Section 2.2 and the electricity demand of the DH generation. For the reference emissions of electricity, monthly average emission factors from 2015 to 2019 [34] were used, presented in Table 3. In Table 4 the minimum and maximum capacities, annual generations, and emission factors of the electricity generation sources used in this study are presented. In addition, it is defined whether the source was a parameter or a variable in the optimization. The modeling of each of the electricity generation sources are presented in detail in the following sections.

2.3.1. Nuclear power

The nuclear power plants in operation in 2050 were assumed similarly as in [35], meaning that from the current power plants Olkiluoto 1 and 2 (890 MW each) would still be in operation, and new plants Olkiluoto 3 (1600 MW) and Hanhikivi 1 (1200 MW) would have started operation. Thus, in total the nuclear power capacity was 4580 MW which was presumed to operate at full capacity continuously for every hour of the year, except for the annual maintenance brakes, which were assumed followingly. Olkiluoto 1: May 24 – June 11, Olkiluoto 2: May 10 – May 24, Olkiluoto 3: August 1 – August 31 [36], and Hanhikivi 1 July 1 – July 31.

2.3.2. CHP industry

CHP industry generates industrial steam and electricity for pulp and paper factories. The variation in generation is relatively small, and for the model a time series from 2019 was used for the electricity generation [33]. However, some changes in fuels were assumed. Currently most of the generation, 80 % in 2015 – 2019, is based on wood fuels, but other fuels with high emissions are also used. However, coal, peat, and oil, which corresponded to 9.0% of the used fuels but 65 % of the emissions, were assumed to be replaced with wood fuels. Thus, fuel usage assumed in the generation was: 89 % wood fuels, 1.5 % other renewables, 6.3 % natural gas, 1.2 % other fossil fuels, and 2.2 % other energy sources. The annual wood fuel usage in CHP industry increased by 5.8 TWh, but as no wood fuels were used in the other electricity and DH generation sources, the total wood fuel usage in the these decreased by 22 % from 74 TWh to 58 TWh, compared to 2015 – 2019 [23]. The emission factor for CHP

Table 2
The shares of the primary heating systems for the building stock scenarios from Fig. 3a.

	Reference	BAU	DH Low	DH High	HP Low	HP High
Primary heating system	Share (%)					
DH	47.9	46.1	11.2	11.2	5.9	5.9
DH retrofit	0.0	6.2	47.4	47.4	29.2	29.2
Oil	13.8	9.2	0.0	0.0	0.0	0.0
Wood	8.1	5.5	0.0	0.0	0.0	0.0
Wood retrofit	0.0	0.0	5.4	5.4	5.5	5.5
Electric	21.4	21.5	0.3	0.3	0.3	0.3
Electric retrofit	0.0	0.0	21.1	21.1	21.2	21.2
GSHP/AWHP	2.9	6.4	6.3	6.3	6.4	6.4
GSHP/AWHP retrofit	0.5	0.7	5.3	5.3	28.8	28.8
Other	5.4	4.5	2.9	2.9	2.9	2.9

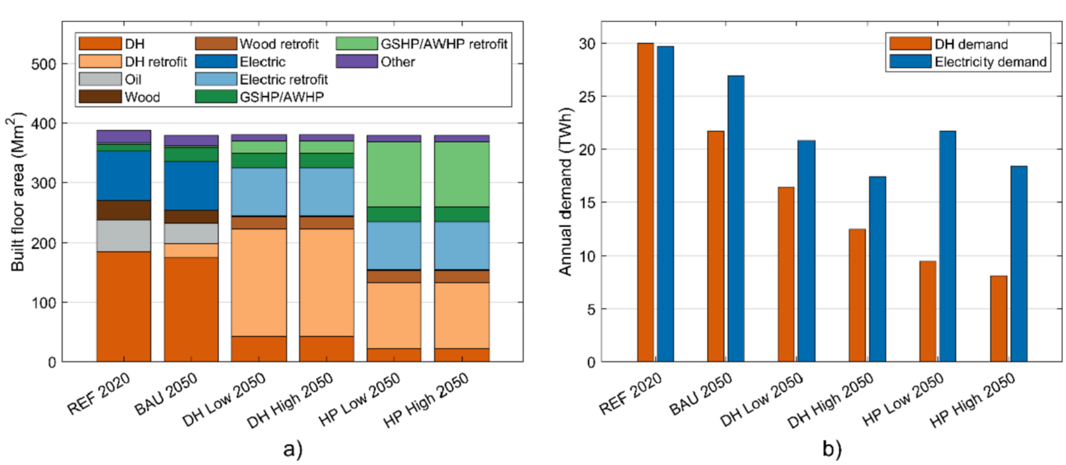

Fig. 3. In a) the built floor areas by primary heating system, and in b) the electricity and DH demands, for the retrofitted building stock, in each scenario [21].

Table 3
Reference emission factor for electricity [34].

Month	1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.	12.
Emission factor (kg-CO_2/MWh)	126.6	120.1	113.0	94.3	81.3	62.1	64.3	67.4	89.7	110.4	111.7	107.7

Table 4
The characteristics of the electricity generation sources.

Generation source	Max capacity	Min capacity	Annual production	Emission factor	Parameter or variable
	MW	MW	TWh	kg-CO_2/MWh	
Nuclear	4580	2800	37.31	0	Parameter
CHP industry	1144	638	9.63	48	Parameter
Wind power	2160 – 21,600	0	7.20 – 71.99	0	Parameter
ROR hydro	1157	245	4.56	0	Parameter
Flexible hydro[1]	1414	102	6.20	0	Variable
CCGT	Not limited	0	Not limited	332	Variable

[1)] Even though the flexible hydro power was a variable its annual production was limited by the annual water inflow to flexible hydro power reservoirs as explained in Section 2.3.3.

industry changed from 110 [23] to 48 kg-CO_2/MWh with these fuel changes.

2.3.3. Hydro power

The availability of hydro power depends on the hydro reservoir content and the hydro inflow energy. Historical data from the Finnish Environment Institute [37] for the inflow energy was utilized from 1978 to 2014. From the data a median daily inflow was chosen for this study. The daily data available was in GWh/week which was converted to hourly values with the assumption that the inflow is the same for every hour during a day. The annual inflow energy was 11.3 TWh. In addition, in the sensitivity analysis in Section 3.3.3 the water inflow was altered to represent a dry or a wet year.

Not all hydro power plants in Finland are flexible plants with hydro reservoirs, instead they are run-of-river, ROR, power plants which operate directly based on the water flow. Pöyry [38] estimated that 45 % of the hydro capacity in Finland is ROR hydro and 55 % flexible. Thus, the inflow energy and capacity were divided by 45 % to ROR (1157 MW) and 55 % to flexible hydro power plants (1414 MW) [39]. Also, a minimum value for flexible hydro operation, based on 2019 generation data [40], was assumed as 102 MWh/h. The maximum hydro reservoir capacity was 5.53 TWh [37]. The hourly water inflow to ROR hydro power plants, and the consequent power generation, is presented in Fig. 4a together with the ROR hydro spillover which occurs when the water inflow exceeds the generation capacity. In Fig. 4b the water inflow to the reservoirs connected to the flexible hydro power is presented, which affected the possible annual generation, whereas the hourly generation of the flexible hydro power was only limited by its minimum and maximum capacities. In Fig. 4 the values were based on the median water inflow.

2.3.4. Wind power

This study utilized a simulated wind power generation time series from [41] where a statistical model for wind power generation modeling without measurement data was presented. The model used a methodology for modeling the generation for multiple new wind power plant locations and modeled the wind power generation for 1080 MW of aggregated capacity. The simulation included 100 simulation runs over a year with hourly resolution, from which an average scenario was selected for this study. The generation of this aggregated capacity varied

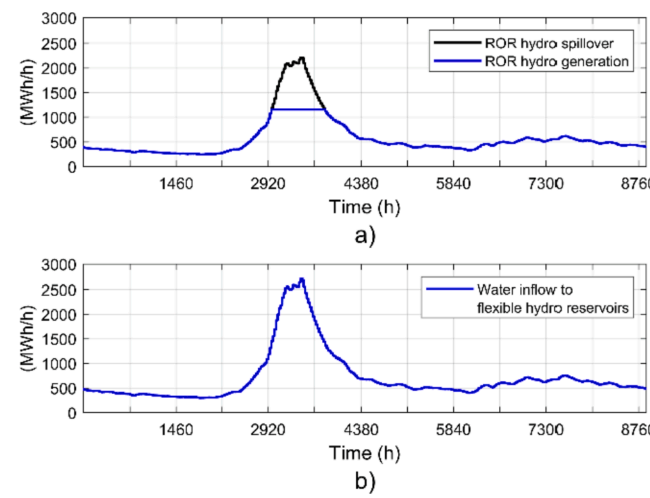

Fig. 4. In a) the water inflow to ROR hydro plants and the consequent ROR hydro electricity generation and the spillover which is a result of exceeding the capacity. In b), the water inflow to hydro reservoirs connected to flexible hydro power plants [37].

between 0 and 936 MWh/h over one year, with a capacity factor of 0.38, and is presented in Fig. 5. The capacity factor is defined as the annual electricity generation divided by electricity generated if the plant would operate at full capacity over a year. In the simulations in this study the time series in Fig. 5 was scaled up to obtain the generation profiles of 10 wind power capacities from 2160 to 21 600 MW. The average capacity factor of wind turbines assembled in Finland between 2011 and 2018 was 0.34 [42] so 0.38 was considered a good estimate for the generation in 2050.

2.3.5. Combined cycle gas turbine

As a last resort for electricity generation, combined cycle gas turbine generation with a 60 % efficiency and natural gas as a fuel was used [43]. Thus, the emission factor for the CCGT plant was 332 kg-CO_2/

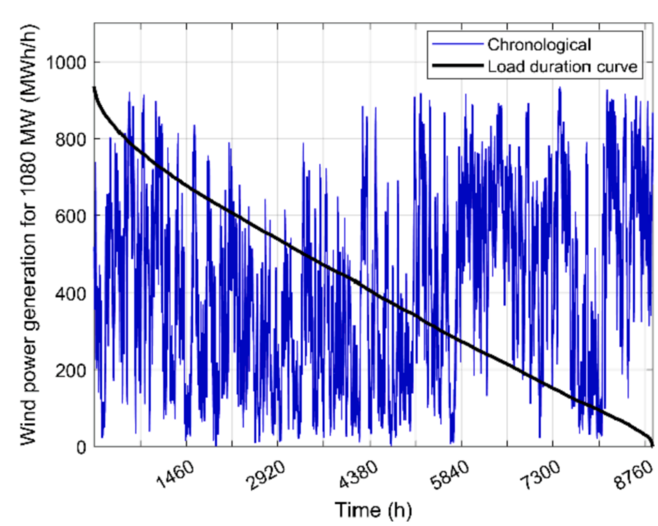

Fig. 5. Wind power generation for 1080 MW of aggregated wind power capacity from [41].

MWh [44].

2.4. District heat generation sources and demand

The district heating demand in Finland was modeled as the DH demand of the building stock scenarios presented in Section 2.2 but including DH losses of 9.7 % [45]. In addition, the demand from industrial and warehouse buildings was added to them. According to [30] these correspond to 13.4 % of the floor area heated with DH, and their demand was assumed directly proportional to it. Thus, the demands were 5.2 and 3.7 TWh annually, in the reference and BAU scenarios, respectively. For the retrofit building scenarios, the demand in BAU was used, so no retrofits were assumed to be conducted for the industrial and warehouse buildings. The total DH demand in Finland with each building stock scenario are presented in Table 5. The reference emission factor for DH generation was 137 kg-CO_2/MWh [46].

The required hourly supply temperature of the DH network was calculated according to Eq. (1) [47], but with a minimum temperature of 70 °C, where the dimensioning temperature was −26 °C, and the outdoor temperature according to the weather test reference year (TRY2012-Vantaa) [48]. The return temperature was assumed to be always 45 °C, based on [49–51].

$$T_{DH,supply} = 115^{\circ}\mathrm{C} + \left(T_{dimensioning} + T_{outdoor}\right)\frac{45^{\circ}\mathrm{C}}{\left(8^{\circ}\mathrm{C} - T_{dimensioning}\right)} \quad (1)$$

As mentioned in Section 2.1 the DH generation consisted of deep heat well heat pumps (different from household heat pumps in Section 2.2.), electric boilers, short-term thermal storage, and fossil heat boilers all connected to the district heating network. Thus, the existing DH power plants were assumed to be closed. The capacity of the heat pumps was limited to either 20 % or 30 % of the peak DH demand and the delivered temperature to 85 °C. Although, with current technology the limit could be higher, but with increased costs and a decreased power factor. Thus, when the supply temperature in the DH network was higher than 85 °C the heat from the HPs was required to be raised with electric or fossil boilers. This also limited the available heat of the heat pumps in the model. Moreover, the heat pumps were prioritized over the electric boilers and thermal storage. This was necessary when the overgeneration of electricity was excessive due to high amounts of wind power, so that no electricity was ‘wasted’ by using less efficient sources for PtH when it resulted in the same emissions. The heat pumps utilized deep heat wells, described in Section 2.5, as their heat source, and their COP was assumed 3.0.

The electric boilers were used for direct PtH to the DH network, supplementing the heat from the HPs, and charging the thermal storage. Their capacity was always limited to a maximum of 50 % of the peak DH demand, and an efficiency of 90 % was assumed.

The effect of the thermal storage size on the system was tested with three different capacities, 10, 50, and 100 GWh. For example, the 50 GWh storage corresponded from 16 (in BAU) to 36 h (HP High) of average DH demand. The charging and discharging efficiencies were 90 % each and the hourly efficiency 99.8 %, meaning an hourly loss of 0.2 %.

If necessary, the fossil heat boilers were used for increasing the temperature of heat from the HPs and for directly supplying heat to the DH network. They were assumed to utilize natural gas as a fuel with a 94 % efficiency [52], resulting in an emission factor of 212 kg-CO_2/MWh [44].

The emission factor was zero for all except the heat boiler using fossil fuels, as all the other sources used electricity as the source of energy, and the emissions were calculated as part of the electricity generation. In Table 6 the maximum capacities of each of the district heat generation sources are presented for each of the building stock development scenarios. For DHWHPs the two capacity options of 20 % or 30 % of the peak DH demand are presented.

Table 5
Total DH demand in Finland with different retrofit scenarios and the reference scenario.

		Retrofit scenario for 2050				
	Ref 2020	BAU	DH Low	DH High	HP Low	HP High
Total DH demand (TWh)	38.4	27.8	21.9	17.6	14.3	12.7

2.5. Deep heat wells

Heat pumps are considered as an important technology for providing carbon-free heat and energy system flexibility through PtH sector coupling. HPs are well applicable to large-scale uses such as community or district heating, but attention needs to be paid to the adequacy of the heat source compared to small-scale uses. To ensure reliable operation of the HPs even under peak conditions, deep boreholes in bedrock were chosen as the main heat source for the HPs. The boreholes could extend up to 2 km deep in ground, enabling in Finnish conditions even up to 40-times more heat output than from a traditional shallow ground heat well [16]. Such deep heat systems could well be placed in denser urban areas, where DH is typically employed.

Contrary to geothermal primary energy utilization where the output temperature is sufficient for direct use in DH, or even to generate electricity through a thermodynamic cycle, the temperature from a deep heat well system would necessitate a heat pump. The direct use of ground’s geothermal heat would require in Scandinavia drilling down to at least 6 km to reach high enough temperature (>120 °C), whereas in volcanic areas the drilling depth could be minimal. Deep boreholes for both direct heating and for heat pumps are under investigation to determine their technical and economic feasibility in different applications. The drilling technology needed has already been established.

Because of the geothermal gradient in ground, deep heat wells receive an extra boost from a higher temperature, which improves the COP of the heat pump [16]. The wells can also be coupled with other heat sources, and charged to compensate for the heat extracted, but here they were used as the single heat source for heat pumps. To reach a required thermal output, several deep heat wells can be used in parallel, which would then require more accurate planning of the well pattern to avoid too strong thermal interaction between the wells.

There are two basic technology approaches for a deep heat well: A U-shaped closed tube and a coaxial open well [53]. In the coaxial borehole, the circulating water may partly be in contact with the bedrock, whereas the plastic U-tube has closed circulation. The coaxial tube reaches a better heat transfer rate and thus higher output, for which reason it was employed here.

The principle of the deep heat well with a coaxial pipe is shown in

Table 6
Maximum capacities of the district heat generation sources for each of the building stock development scenario.

	Building development scenario				
Generation source	BAU	DH Low	DH High	HP Low	HP High
DHWHP 20 % (MW)	2740	2330	2020	1640	1550
DHWHP 30 % (MW)	4110	3500	3040	2450	2320
Thermal storage (GWh)	10, 50, 100	10, 50, 100	10, 50, 100	10, 50, 100	10, 50, 100
Electric boiler (MW)	6850	5830	5060	4090	3870
Fossil heat boiler (MW)	Not limited	Not limited	Not limited	Not limited	Not limited

Fig. 6. The tube consists of a steel inner pipe, which is installed in the heat well and of an outer pipe section in which the cold liquid flows down and heats up before returning in the inner pipe. The thermal conductivity of the steel pipe affects the available energy through possible thermal short-circuiting, but the inner and outer pipes can be insulated using a vacuum layer.

2.6. Economic feasibility

To examine how the measures conducted in this study would affect the costs of the energy system, the costs resulting from the building retrofits as well the energy system measures were determined. These were performed as post-processing of the simulation results. For the energy system the levelized cost of electricity and DH were calculated for the simulated generation scenarios in 2050. Later these are referred to as LCOE and LCODH. The parameters used for these calculations are presented in Table 7. The fuel costs consider the efficiencies of the power plants, which were 60 %, 37 %, and 94 % for CCGT, nuclear, and fossil heat boiler, respectively [43,52,54]. For CHP industry the costs are represented only for the electricity generation, divided according to the benefit allocation method for electricity and heat, resulting in a 29.1 % share dedicated to electricity [23]. Moreover, for CHP industry the fuel costs for "other fossil" were calculated as natural gas, and "other renewables" and "other energy sources" as biomass [23]. For nuclear power, two different investment costs were used depending if the power plant was constructed on a property which already included a nuclear power plant as in [54]. The capacities built on existing and new properties were 1600 and 2980 MW, respectively. In addition, the assumed price for CO_2 emissions were 20.1 €/t-CO_2, an average of the 2018 – 2019 EU ETS [55].

For each of the generation sources a levelized cost of energy was calculated considering the technology specific economic lifetime and the simulated annual generation. They were then used to calculate hourly weighted cost of electricity and district heat in 2050. The hourly levelized cost of electricity was considered in the levelized cost of district heat, as was the electricity transmissions and distribution (T&D) cost, which for industrial customers include a capacity cost [56,57] and thus varied between 14.5 and 34.8 €/MWh depending on the capacity of the connected DH generation sources.

The costs related to the changes in the building stock were also considered. These were the cost of retrofits conducted and the separate heating. Also, for the electricity used in the buildings the T&D cost and electricity tax for residential customers was included as 66.44 €/MWh [56,57]. The costs for the retrofits and separate heating are presented in Table 8.

With these parameters the total costs in 2050 were determined which

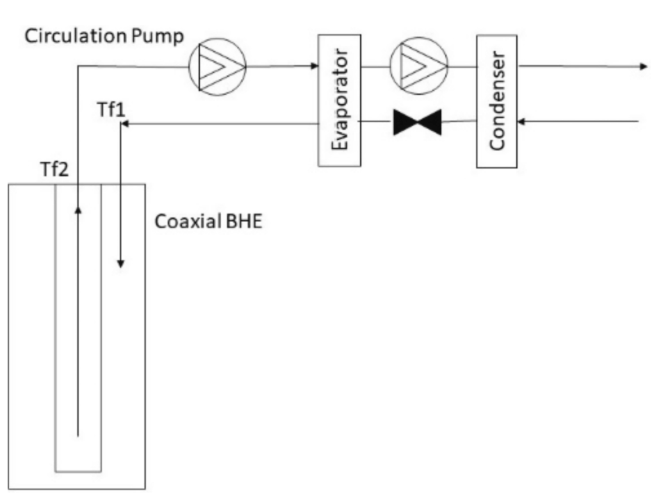

Fig. 6. Principle of a deep well heat pump system [53].

Table 7
Cost parameters for determining the 2050 LCOE and LCODH in Finland [43,54,58,59].

Technology	Investment cost	Fixed O&M cost	Variable O&M cost	Fuel cost	Economic lifetime
	k€/MW	€/MW	€/MWh	€/MWh	a
Nuclear, new location	4950	–	10.41	5.7	40
Nuclear, existing location	3600	–	10.41	5.7	40
Hydro	1700	34 000	–	–	80
Wind	1120	14 000	1.5	–	27
CCGT	880	29 300	4.4	58.3	25
CHP industry, biomass	1020	149 000	4.5	9.0	25
CHP industry, natural gas	1020	149 000	4.5	12.8	25
Deep heat well system	4300	2000	2.7	LCOE	25
Electric boiler	70	1070	0.5	LCOE	20
Natural gas heat boiler	60	1950	1.1	34.95	25
Thermal storage	4[2]	700[2]	–	LCOE	20

[2)] Per MWh.

Table 8
Building stock retrofit and separate heating costs.

Building stock retrofit scenario	Energy retrofit investment cost	Maintenance and renewal [3]	Oil heating cost	Wood heating cost
	M€/a	M€/a	M€/a	M€/a
REF (2020)	0	0	1289	384
BAU	0	0	697	207
DH Low	854	8.5	0	167
DH High	2039	20.4	0	116
HP Low	1115	11.2	0	167
HP High	2305	23.0	0	116

[3)] Assumed 1% of the investment cost.

consisted of cost of electricity and DH used in Finland, building stock retrofit, separate heating for buildings, and electricity T&D cost for residential customers. Also, the corresponding reference costs for the 2020 system were determined using the weighted annual average Nordpool elspot market price for electricity from 2015 to 2019 of 38.0 €/MWh [60], and 59.7 €/MWh for DH [61]. The costs for oil and wood fuel used by buildings were 92.7 and 52.2 €/MWh respectively [59].

Next the costs over 30 years, from 2021 to 2050, were determined and discounted to present value with a 5 % discount rate. This was done so that the starting point was the costs in 2021, which were assumed the same as the reference costs of 2020, and the end point the modeled costs in 2050. The percentual change compared to the previous year was assumed to be the same for each year. This is presented in Eq. (2).

$$Presentvalue = C_{total,2021}\left(\frac{1+p}{1+r}\right)\frac{\left(\frac{1+p}{1+r}\right)^{30}-1}{\left(\frac{1+p}{1+r}\right)-1} \tag{2}$$

where $C_{total,2021}$ includes the total reference costs for electricity and DH in Finland in 2020, the T&D cost for residential customers in 2020, and the 2020 building costs. Then p, the yearly change in the costs, is defined so that in 30 years the costs reach the corresponding modeled costs of 2050. And r is the discount rate. Also, the building cost includes the cost of the building retrofits, the maintenance and renewal, and the separate heating cost.

In addition, a reference scenario was determined where the starting point was the same, but the end point was 2050 costs with BAU scenario for buildings and electricity and DH costs, in €/MWh, were assumed the same as in 2020, i.e. assuming that the generation shares in electricity and DH generation would not change during this period.

2.7. Optimization method

Here the MILP optimization is presented in more detail. It consisted of two objective functions, one for electricity generation and one for district heat generation in 2050. These two were then used to solve the problem by iterations. The hourly simulations were performed by using a Matlab (v 9.10) – GAMS (v 27.3.0) platform and the objectives solved with CPLEX solver. Equations (3)–(11) present the electricity generation optimization, where the objective was to minimize the emissions from CCGT generation, as it was the only flexible electricity generation source with emissions.

The equations for the electricity generation optimization were:

$$Minimize \sum_{t=1}^{T} EF^{CCGT} P_{t,i}^{CCGT} \tag{3}$$

S.t.

$$D_{t,i}^{elec} \leq P_{t,i}^{fixed} + P_{t,i}^{hydroflex} + P_{t,i}^{CCGT}, \ \forall t, \forall i \tag{4}$$

$$D_{t,i}^{elec} = D_{t,i}^{elec\ Finland} + D_{t,i}^{elec\ buildings} + D_{t,i-1}^{elec\ DH}, \ \forall t, \forall\ i > 1 \tag{5}$$

$$D_{t,i}^{elec} = D_{t,i}^{elec\ Finland} + D_{t,i}^{elec\ buildings} + D_{t,i}^{elec\ DH,0}, \ \forall t, \forall i = 1 \tag{6}$$

$$SOC_{t,i}^{hydro} = SOC_{t-1,i}^{hydro} + Inflow_{t,i}^{hydro} + P_{t,i}^{hydroflex}, \ \forall i, \ \forall t > 1 \tag{7}$$

$$SOC_{t,i}^{hydro} = 3500000, \forall i, \ \forall t = 1 \tag{8}$$

$$0.05SOC^{hydro,max} \leq SOC_{t,i}^{hydro} \leq SOC^{hydro,max}, \ \forall i, \ \forall t > 1 \tag{9}$$

$$P^{hydroflex,min} \leq P_{t,i}^{hydroflex} \leq P^{hydroflex,max}, \ \forall t, \ \forall i \tag{10}$$

$$P_{t,i}^{hydroflex}, P_{t,i}^{CCGT} \geq 0, \ \forall t, \ \forall i \tag{11}$$

From the electricity generation optimization, the electricity mismatch, before utilizing the CCGT generation was calculated, where negative values represent undergeneration and positive values overgeneration of electricity. This was transferred as a parameter ($EM_{t,i}^{elec,opt}$) to the district heat generation optimization, where the objective was to minimize the combined emissions from the fossil heat boiler for DH and the electricity undergeneration which would have to be covered with CCGT generation. The electricity mismatch was defined as:

$$EM_{t,i}^{elec,opt} = P_{t,i}^{fixed} + P_{t,i}^{hydroflex} - D_{t,i}^{elec} \tag{12}$$

The equations for district heat generation optimization were:

$$Minimize \sum_{t=1}^{T} EF^{FB} Q_{t,i}^{FB} + EF^{CCGT} P_{t,i}^{underproduction} \tag{13}$$

S.t.

$$D_{t,i}^{DH} = Q_{t,i}^{HP} + \eta^{EB} P_{t,i}^{EB} + Q_{t,i}^{TS,dch} + Q_{t,i}^{FB}, \forall t, \forall i \tag{14}$$

$$EM_{t,i}^{DH,opt} = EM_{t,i}^{elec,opt} - \left(P_{t,i}^{HP} - P_{t,i-1}^{HP}\right) - \left(P_{t,i}^{EB} - P_{t,i-1}^{EB}\right) - \left(P_{t,i}^{TS,ch} - P_{t,i-1}^{TS,ch}\right), \forall t, \forall i > 1 \tag{15}$$

$$EM_{t,i}^{DH,opt} = EM_{t,i}^{elec,opt} - \left(P_{t,i}^{HP} - P_{t}^{HP,0}\right) - \left(P_{t,i}^{EB} - P_{t}^{EB,0}\right) - \left(P_{t,i}^{TS,ch} - P_{t}^{TS,ch,0}\right), \ \forall t, \ \forall i = 1 \tag{16}$$

$$P_{t,i}^{underproduction} \geq -EM_{t,i}^{DH,opt}, \forall t, \forall i \tag{17}$$

$$SOC_{t,i}^{TS} = \eta^{TS,hourly} SOC_{t-1,i}^{TS} + \eta^{TS,ch} P_{t,i}^{TS,ch} + \frac{Q_{t,i}^{TS,dch}}{\eta^{TS,dch}}, \forall i, \forall t > 1 \tag{18}$$

$$SOC_{t,i}^{TS} = \eta^{TS,hourly} SOC_{t,i}^{TS,0} + \eta^{TS,ch} P_{t,i}^{TS,ch} + \frac{Q_{t,i}^{TS,dch}}{\eta^{TS,dch}}, \forall i, \forall t = 1 \tag{19}$$

$$0 \leq SOC_{t,i}^{TS} \leq SOC^{TS,max}, \forall t, \forall i \tag{20}$$

$$P_{t,i}^{HP} = \frac{Q_{t,i}^{HP}}{COP^{HP}}, \forall t, \forall i \tag{21}$$

$$Q_{t}^{HP,min} \leq Q_{t,i}^{HP} \leq Q_{t}^{HP,max}, \forall t, \forall i \tag{22}$$

$$0 \leq Q_{t,i}^{TS,dch} \leq 0.05SOC^{TS,max}\eta^{TS,dch}B1_{t,i}, \forall t, \forall i \tag{23}$$

$$0 \leq P_{t,i}^{TS,ch} \leq 0.05SOC^{TS,max}B2_{t,i}, \forall t, \forall i \tag{24}$$

$$P_{t,i}^{TS,ch} + P_{t,i}^{EB} \leq P_{t,i}^{EB,max}, \forall t, \forall i \tag{25}$$

$$B1_{t,i} + B2_{t,i} \leq 1, \forall t, \forall i \tag{26}$$

$$Q_{t,i}^{HP}, P_{t,i}^{HP}, Q_{t,i}^{FB}, Q_{t,i}^{EB}, P_{t,i}^{underproduction} \geq 0, \forall t, \forall i \tag{27}$$

$$B1_{t,i}, B2_{t,i} \in \{0, 1\}, \forall t, \forall i \tag{28}$$

From the district heat generation optimization, the aggregated electricity demand of the heat pumps, electric boilers, and thermal storage charging were transferred as a parameter ($D_{t,i}^{elecDH}$) to the electricity demand for the next iteration of the electricity generation optimization. As described in Section 2.1 these two objective functions were solved sequentially, until the difference in the total emissions between two iterations were less than 0.01 %.

3. Results

This Section presents the results obtained with the methods presented in Section 2, for the proposed system setup. In addition, a sensitivity analysis for the results is presented in Section 3.3.

3.1. Carbon dioxide emissions and costs over 30 years

Fig. 7 presents the total energy system emissions from the electricity and district heat generations, and separate heating for the buildings over a 30-year period, as well as the difference in total costs over 30 years compared to a BAU Ref scenario. The emissions were calculated so that they were assumed to decrease from the reference 2020 emissions, 18.27 Mt-CO_2, to the simulated emissions over the 30-year period, with a constant yearly percentage compared to the previous year. The costs over 30 years were determined as described in Section 2.6. The annual emissions from separate heating for the buildings, i.e. oil, were 4.5, 2.4, and 0.0 Mt-CO_2, for the reference, BAU, and retrofit scenarios, respectively. The 'Ref' scenarios in Fig. 7 assume that the building stock would develop according to the respective building scenario and the electricity and DH generations would remain the same, in terms of CO_2/MWh and €/MWh, over the 30-year period. As the BAU scenario for the buildings was assumed to be reached with the current trajectory of the development of the building stock, it was chosen as the reference where the costs of the other scenarios, with additional measures to reduce emissions, were compared to. The figure presents the results, when the DHWHP capacity was limited to either 20 % or 30 % of the peak DH demand, and the thermal storage had a capacity of 10, 50, or 100 GWh. Further, it shows the effect of 10 levels of wind power capacity, from 2160 MW to 21 600 MW, with emissions decreasing as the capacity increases. The

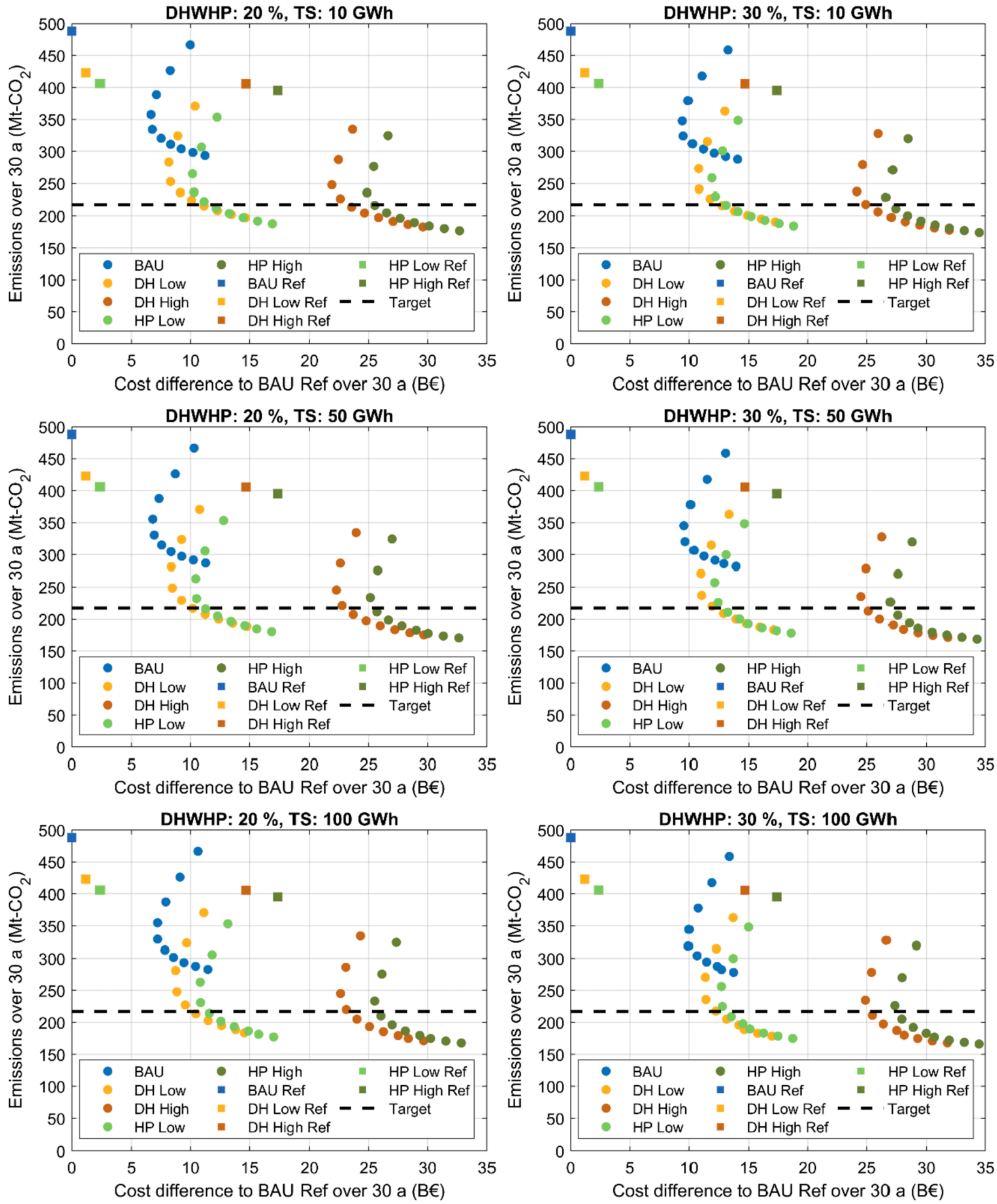

Fig. 7. Emissions and costs for the reference and retrofit scenarios over 30 years, with 10 levels of wind power capacity, 20 or 30 % of DHWHP capacity, 10, 50, or 100 GWh of thermal storage, and the five development paths for the building stock.

target level of emissions over 30 years was defined so that the annual emissions in 2050 would have reduced 90 % from the reference emissions, i.e., to 1.827 Mt-CO_2. Over 30 years this target resulted in 217.3 Mt-CO_2.

With only the building retrofits, the emissions decreased from the 488 Mt-CO_2 in BAU Ref to between 423 and 395 Mt-CO_2, with increased costs of 1.2 to 17.4B€, respectively. When the measures in the electricity and DH generations were included, the total emissions decreased significantly, and several scenarios surpassed the target level. Although, notably if the buildings continued according to the BAU scenario, no combination of energy system measures were enough to reach the target. The High retrofit scenarios for the building stock, together with the energy system measures, attained approximately 5 to 13 % lower emissions compared to the Low scenarios, but with roughly double the cost.

The amount of wind power in the system had a large effect on emissions with each building stock scenario, and in general the higher the retrofit level was on the buildings, the less wind power was required to reach the target emissions, and vice versa. For HP High scenario, the required wind capacity to reach the target was 8640 MW, and for DH Low even 15 120 MW with DHWHP 20 % and 10 GWh of thermal storage. Notably for all scenarios, as wind power capacity was increased, the costs first decreased and began to increase after 6480 to 12 960 MW of wind power capacity, depending on the scenario. This is because wind power had a lower generation cost compared to CCGT, which it was replacing. But at a certain point, the cost of additional wind power capacity was greater than the added cost-benefit for the total system, and thus the total costs increased. In other words, from the additional wind power capacity a higher share of generation required to be curtailed due to missing power demand. Emission-wise there was always a benefit, although marginally decreasing. Increasing the DHWHP capacity from 20 % to 30 % reduced the emissions but in tandem increased the costs

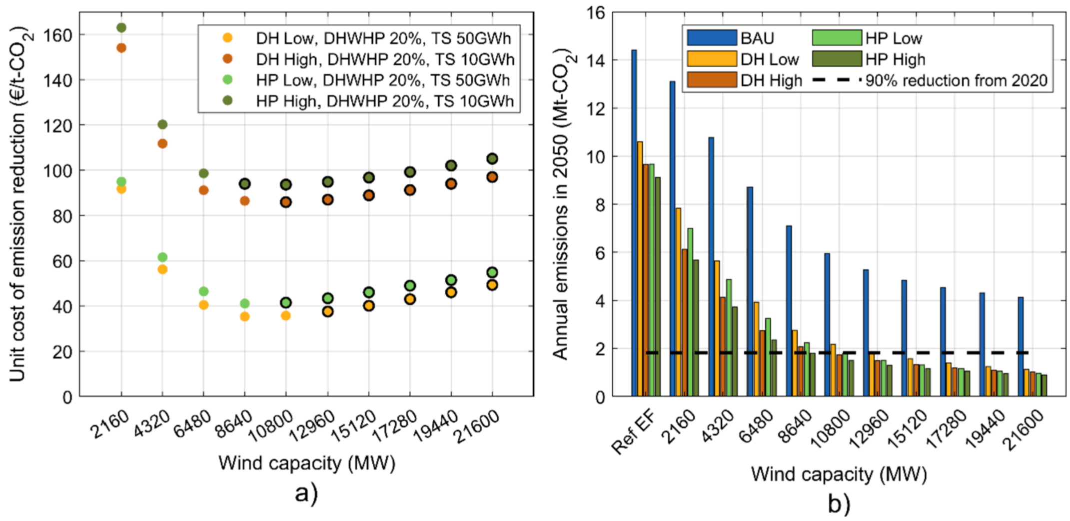

Fig. 8. In a) the unit cost of emission reductions for scenarios which include the lowest cost set of measures to reach the emission reduction target for each building retrofit scenario. In b) the annual emissions of these scenarios compared to the target emission level.

Table 9
Lowest unit cost scenarios which reach the set target emissions over 30 years for each of the building stock retrofit scenarios. Capacities are the simulated ones in 2050.

		Building stock retrofit scenario			
Parameter	Unit	DH Low	DH High	HP Low	HP High
Wind capacity	MW	12 960	10 800	10 800	8640
Heat pump capacity	MW	2330	2020	1640	1550
Thermal storage capacity	GWh	50	10	50	10
Electric boiler capacity	MW	5500	8790	3930	3530
Fossil heat boiler capacity	MW	10 130	4600	7100	6720
CCGT capacity	MW	5550	5170	5810	5420
Total emissions over 30 a	Mt-CO_2	217.0	213.7	216.1	216.4
Emission reduction over 30 a	%	55.5	56.2	55.7	55.7
Emissions in 2050	Mt-CO_2	1.82	1.73	1.80	1.80
Cost difference to BAU Ref over 30 a	B€	10.18	23.56	11.27	25.53
Unit cost of emission reductions	€/t-CO_2	37.6	85.9	41.5	94.0

even more. The size of the thermal storage had a much more balanced effect on the costs and emissions, but a much smaller one. The target emissions were achieved with the lowest cost increase, 10.2B€, with DH Low building stock scenario, 12 960 MW of wind power, 20 % of DHWHP capacity, and 50 GWh of thermal storage. Whereas, the lowest emissions, 166 Mt-CO_2 over 30 years and 0.70 Mt-CO_2 in 2050 (reduction of 96%), were achieved with HP High building retrofit scenario together with 21 600 MW of wind power, DHWHPs to 30 %, and 100 GWh of thermal storage, with a total cost of 34.5B€.

Next for each of the building retrofit options, one capacity for the DHWHPs and thermal storage were chosen for further examination, but all 10 levels of wind power were kept. The capacities were chosen so that the lowest cost scenario, for each building retrofit option, to reach the emission target was included. For all, the DHWHPs were dimensioned to 20 % of the peak DH demand, and the Low scenarios had 50 GWh of thermal storage while the High scenarios had 10 GWh. The unit costs of emission reductions in these scenarios are presented in Fig. 8a, and the simulated annual emissions in 2050 in Fig. 8b, where also the BAU scenario is included with 20 % of DHWHP and 50 GWh of thermal storage capacity. In Fig. 8b the bars for Ref EF are the annual emissions with the 2020 reference emission factors. Only scenarios with the data points outlined with black in Fig. 8a did reach the emission target. Similarly to the total costs, and due to the same reasons, the unit costs of emission reductions began to increase at a certain point. The lowest unit cost by which the target was achieved, 37.6 €/t-CO_2, was with DH Low with 12 960 MW of wind power capacity. In general, for the Low scenarios the unit costs were considerably lower than in the High scenarios. The capacities of the measures in each of the lowest unit cost scenarios which reached the target emissions are presented in Table 9. These are also the same scenarios to reach the target emission with the lowest costs over 30 years from Fig. 7.

3.2. *Energy balance with DH Low building stock*

In Fig. 9a and b the annual generations of electricity and district heat are presented for DH Low building stock scenario with 10 levels of wind power, DHWHPs limited to 20 % of the peak DH demand, and 50 GWh of thermal storage, for the simulated year 2050. As wind power capacity was increased in the system the amount of CCGT generation decreased by a great extent, whereas the CCGT capacity only decreased from 5910 to 5280 MW with 21 600 MW of wind power, highlighting that high ramp-ups of backup power were still required. Moreover, with more wind power the utilization of electric boilers and thermal storage in DH generation increased, while the annual DHWHP generation remained nearly the same. The thermal storage was most widely used in the scenarios with intermediate amounts of wind power. Moreover, the increase of electric boiler and thermal storage utilization is displayed in increased demand of electricity in Fig. 9a. In addition, in Fig. 9a, the amount of excess wind power generation is presented as the amount which exceeds the electricity demand. This excess generation, prone to be curtailed, was 14.9 TWh with 12 960 MW and rose to 41.0 TWh with 21 600 MW of wind capacity.

In Fig. 10a and b the stacked load duration curves over one year, 2050, of the electricity and district heat generations are presented, with the scenario with 12 960 MW of wind power from Fig. 9, which was overall the least costly scenario to reach the set target level of emissions. In Fig. 10a the wind power generation is divided in the generation which was possible to be utilized by the electricity demand, and the part that was not i.e., excess generation prone to be curtailed, shown as negative values. The share of the excess wind generation of the total wind generation was significant, 34 % as also seen in Fig. 9a, and so was the power level of it, up to 7500 MWh/h, as seen in Fig. 10a. Moreover, the peak generation of the CCGT generation was high, 5550 MWh/h, but the

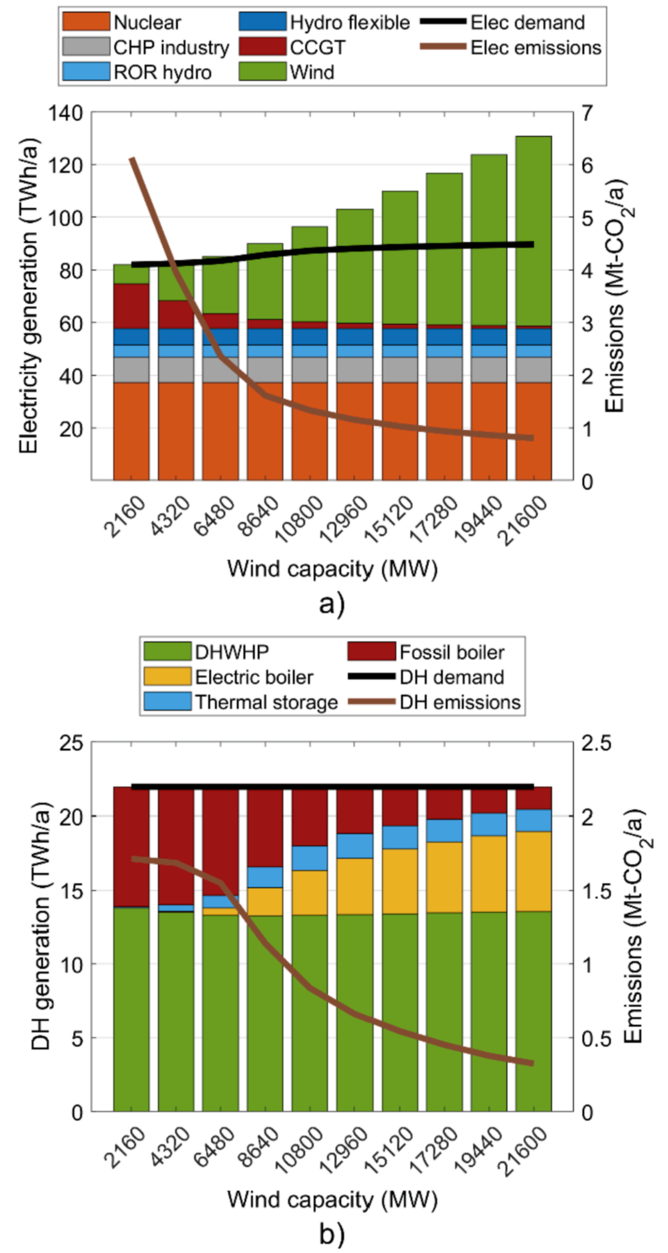

Fig 9. The 2050 annual electricity generation, in a), and DH generation, in b), with different amounts of wind capacity in the system, with DH Low building stock scenario, 20 % DHWHPs, and 50 GWh of thermal storage.

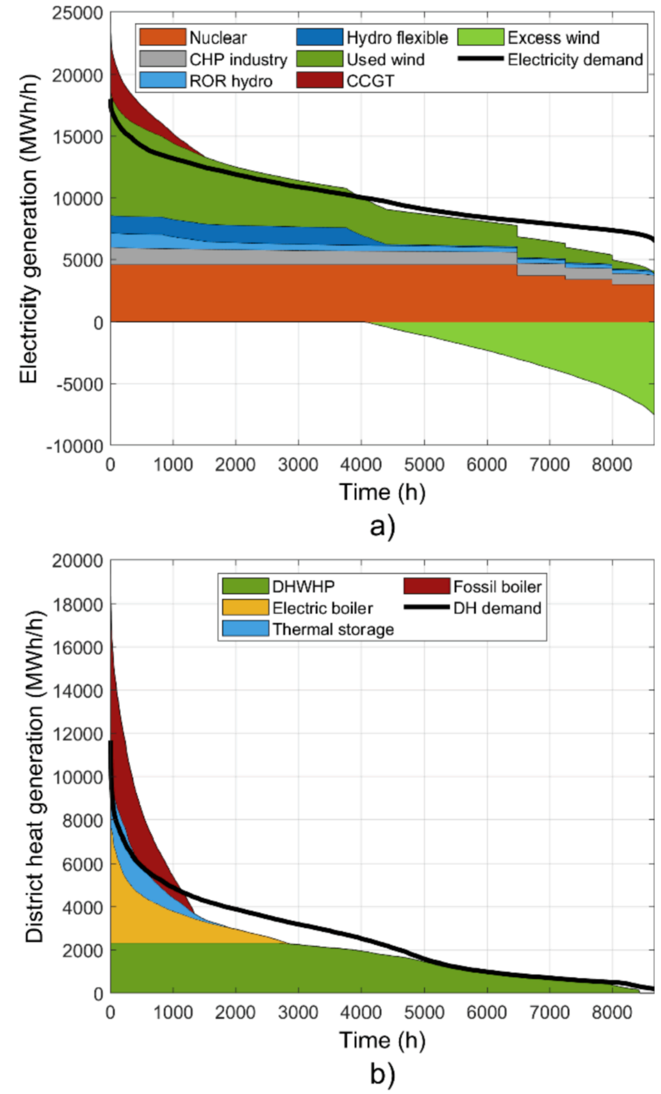

Fig. 10. The stacked load duration curves of the electricity, in a), and district heat, in b), generations over one year with DH Low building stock scenario, 12 960 MW of wind capacity, 20 % DHWHPs, and 50 GWh of thermal storage. The excess generation from wind power is displayed with negative values.

total hours needed it to be operated reasonably low, with 1509 h. In Fig. 10b the high demand of back-up capacity required for the DH generation from the fossil heat boiler is displayed. The peak generation from it reached 10 130 MWh/h, whereas the total hours it was operational were 1341 annually, highlighting that the ramp ups required were significant. The variation in the generation of the electric boilers was also relatively high, whereas the generation from the DHWHPs was more stable over the year.

In Fig. 11 the hourly electricity and DH generations are presented over two example seven day periods, one with cold temperature and one with warm temperature. The weeks were chosen to represent well the variation in the generation and demand of the modeled energy system. During the cold week the CCGT generation was operational when the flexible hydro power was not enough to satisfy the electricity demand during hours with lower wind power generation. Moreover, in both figures for the electricity generation the electricity demand is displayed with and without the electricity demand from the district heat generation. For the cold week, these two differed especially in hours with high wind generation, during which the electric boilers were in operation, and the thermal storage was charged. During hours of lower wind generation, only the electricity demand of the DHWHPs was added to the electricity demand, as in terms of emissions it was beneficial to operate them. During the cold week, the DH demand was mainly covered with generation from the fossil heat boilers, which capacity and energy requirement was significant, and DHWHPs as the wind generation was limited. Moreover, during the hours when the outdoor air temperature, presented in the right axis, decreased close to −20 °C, the temperature requirement of the DH network rose above the possible temperature of the heat supplied from the DHWHPs, 85 °C, as described in Section 2.4. This meant that the temperature of the heat from the DHWHPs was required to be further raised with either electric or fossil boilers, which is displayed in the figures with decreased heat supplied from the DHWHPs. In addition, when the wind generation was high and the DH demand lower, the DH demand was possible to be covered without the fossil heat boilers during the cold week, although the temperature was then close to 0 °C.

During the warm example week, the DH generation was significantly

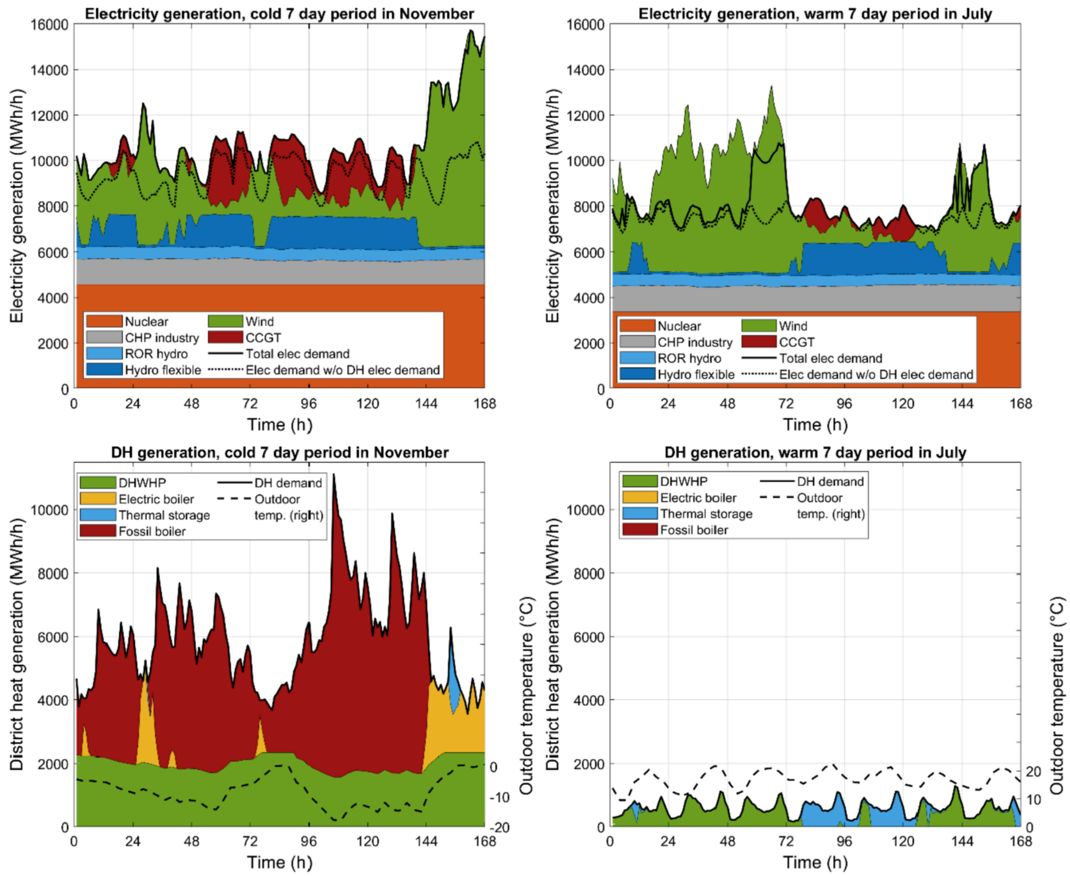

Fig. 11. Hourly electricity and district heat generations over two example seven day periods, one with cold temperature and one with warm temperature. For district heating the outside temperature is also displayed in the right axis of the figures.

lower compared to the cold week, and the fossil heat boilers were not required. Even though the electricity demand was also lower during the warm week, compared to the cold one, there were still hours with low wind generation when the demand was not possible to be covered without the CCGT generation. During these, the DH generation discharged the thermal storage by great extent to limit the DHWHP generation and consequently the electricity demand of the DH generation, which lowered the need for CCGT generation. In both example weeks the operation of the flexible hydro power is visible as a measure to limit the need for the CCGT generation.

3.3. Sensitivity analysis

A comprehensive sensitivity analysis was done for the building scenarios to investigate how three important parameters, namely the discount rate, price of CO_2 emissions, and hydro power availability would affect the outcomes. From the building scenarios, cases which reached the emission target with the lowest costs were chosen. The emission target was 90 % emission reductions by 2050 from the 2020 level. This corresponded to maximum 1.83 Mt-CO_2 emissions in 2050. In some cases, also shown in Table 10, this emission level could even be surpassed.

The parameter values used for the sensitivity analysis were the following:

- Discount rate: reference case 0.05, sensitivity range 0.03–0.07.
- CO_2 price: reference case 20.1 €/t-CO_2, sensitivity range 50–90 €/t-CO_2.
- Hydro power: reference case median water inflow of the daily inflow series [37], sensitivity range dry (10th percentile) or wet (90th percentile) year.

Table 10
Base scenario cases for sensitivity analysis.

Building stock retrofit scenario	Wind power capacity	Heat pump capacity	Thermal storage size	Emissions 2050	Unit cost of emission reduction
	MW	%	GWh	Mt-CO_2	€/t-CO_2
DH Low	12 960	20	50	1.82	37.6
DH High	10 800	20	10	1.73	85.9
HP Low	10 800	20	50	1.80	41.5
HP High	8 640	20	10	1.80	94.0

In addition, an interesting question was how the combination of wind power, deep heat well heat pumps, and thermal storage may change, and would that also change the unit costs of emission reductions.

3.3.1. Change in discount rate

As shown in Fig. 12, the Low scenarios with less ambitious building retrofits were more sensitive to a change in the discount rate than the High scenarios. The High scenarios were almost insensitive to the changes in the discount rate, and the unit costs of emission reductions remained almost the same. In the Low scenarios, the change was notable up to some tens of percent.

The changes in the discount rate did not change the combination of wind power, deep heat well heat pumps, and thermal storage from Table 10.

3.3.2. Change in carbon dioxide price

The impact of CO_2 price for the simulated generation is shown in

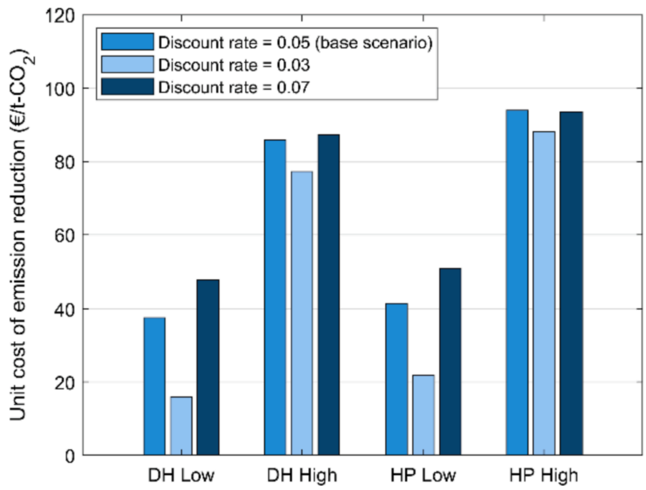

Fig. 12. Effect of change in discount rate to unit costs of emission reductions.

Fig. 13. The changes in the unit costs of emission reductions were very small even with high CO_2 price, which was due to the high decarbonization rate of the energy generation.

3.3.3. Change in hydro power

In the tables to follow, the scenario marked with'normal' is the one achieved in the base case in Table 10. The sensitivity analysis for hydro power was analyzed in terms of cumulative and unit costs of profitability.

Compared to the reference case, the emissions and costs decreased in the wet scenario from that in the normal scenario. During a dry scenario, in the reference case it was not possible to achieve the target emission level, as shown in Table 11.

When preferring cumulatively the best option, presented in Table 12, in the wet scenario, in almost every case, the optimal solution consisted of the same parts as in the base scenario. Only in HP Low and DH high scenarios, cumulatively the best solution was achieved when the thermal storage size or wind capacity was changed.

Contrary in the dry scenario, the emission target was not reached in the base scenario without increasing wind power. In some cases, increasing wind power reduced the need for storage (HP Low) while in others it increased the need of thermal storage (DH Low, HP High).

As a summary, a wet year enabled reducing the emissions very cost effectively. In a dry year, reaching the target emissions through the base scenario would not have been possible, and cumulative costs to reach the target would have become higher. Overall, the emissions were sensitive to changes in the availability of hydro power; the difference between a dry and wet year was large. As the climate change may influence the rainfall, sizing the energy system components just for the base case may not be wise, due to possible higher rainfalls in the northern latitudes. However, the hydro scenarios were very extreme ones and assumed to remain the same for 30 years, so they can be still considered unlikely.

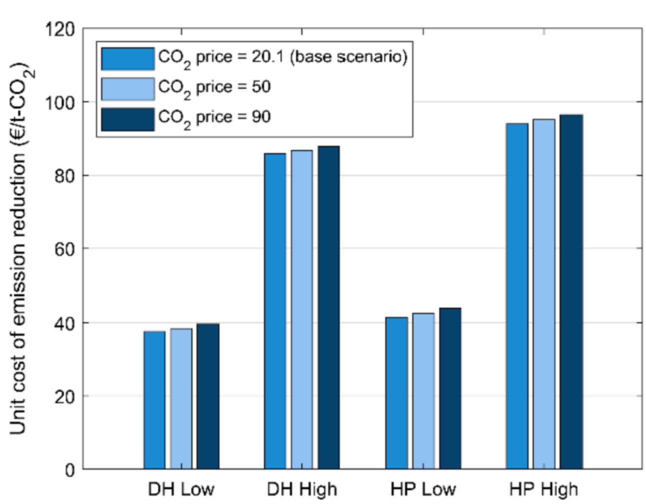

Fig. 13. Effect of change in CO_2-price to unit costs of emission reductions.

Table 11
Impact of hydro power changes in the base scenario.

Scenario	Wind capacity	HP capacity	Thermal storage capacity	Emissions in 2050	Unit cost of emission reduction
	MW	%	GWh	Mt-CO_2	€/t-CO_2
DH Low normal	12 960	20	50	1.82	37.6
DH Low wet				1.64	36.1
DH Low dry				2.33	43.0
DH High normal	10 800	20	10	1.73	85.9
DH High wet				1.55	83.4
DH High dry				2.22	94.5
HP Low normal	10 800	20	50	1.80	41.5
HP Low wet				1.61	39.9
HP Low dry				2.48	49.1
HP High normal	8 640	20	10	1.80	94.0
HP High wet				1.61	90.8
HP High dry				2.59	108.9

Table 12
Optimal way to cut emissions in terms of cumulative costs, with different hydro power assumptions.

Scenario	Wind capacity	HP capacity	Thermal storage capacity	Emissions in 2050	Unit cost of emission reduction
	MW	%	GWh	Mt-CO_2	€/t-CO_2
DH Low normal	12 960	20	50	1.82	37.6
DH Low wet	12 960	20	50	1.64	36.1
DH Low dry	15 120	20	100	1.77	43.5
DH High normal	10 800	20	10	1.73	85.9
DH High wet	8 640	20	50	1.71	81.8
DH High dry	12 960	20	10	1.75	91.3
HP Low normal	10 800	20	50	1.80	41.5
HP Low wet	10 800	20	10	1.77	40.2
HP Low dry	15 120	20	10	1.69	49.1
HP High normal	8 640	20	10	1.80	94.0
HP High wet	8 640	20	10	1.61	90.8
HP High dry	10 800	20	50	1.81	108.8

4. Discussion

As this study explored the possible electricity and DH generation mixes with building stock changes in 2050, it required several assumptions to be made affecting the examination, although the scenario-based analysis together with the sensitivity analysis provided a range for the results. When calculating the changes in emissions and costs over 30 years from the reference values to the calculated 2050 values, it was assumed that the energy system would change in an incremental manner, whereas in reality there would be larger changes during some years, e.g., when the new nuclear power plants would begin their operation. Moreover, as in Section 2.1, CHP for district heating was considered not to operate at all, when in 2015–2019 64.5 % of the DH generation and 24.8 % of electricity generation was covered with it [23]. In addition, electricity import and export which were not considered could be utilized for further balancing the electricity generation and demand.

A high share of nuclear power was assumed to be available in the year 2050, the capacity of which includes some uncertainty and could affect both the emissions end costs of the energy system. Additionally, no alternative for natural gas in the electricity or district heat generation was considered. Moreover, the electricity transmission and distribution networks were not included in this study, as it only took into account the temporal variation of the generation and demand, but for considering the spatial variation they should be included.

The hourly price of energy was determined as the weighted value of the LCOEs and LCODHs in operation every hour. This was somewhat optimistic, as there was no profit margin for the generators. In addition, this made the hourly price less variable compared to if the price of the highest generation required to satisfy the demand would have been used. But, likewise with hours of excess wind power generation the price could have been lower. Also, no economic dispatch model was included in the analysis. In addition, the residual values for the energy system and building stock investments were not considered, nor was the costs of dismantling the current generation sources.

The target level of emissions chosen also affected the results. If a target level of a 95 % reduction would have been chosen, it would not have been achieved with the DH Low scenario. However, with the other retrofit scenarios this target would have still been achievable.

Deep wells were considered as the heat source of the heat pumps, as they generate energy evenly throughout the year. Their advantage over traditional geothermal energy is especially the lower need for surface space for the wells. The required area for the deep wells in this study would be in total approximately 8.5 km^2, while traditional geothermal wells would require a much larger area, over 110 km^2. While each individual deep well requires more space, the increased depth allows taking out more energy per m^2 of horizontal space.

However, this should not be thought of as a “matrix form”, i.e. all wells would be in one cluster - because then the effects of the wells on each other would be greater and decrease the energy generation per well. The required area of 8.5 km^2 could be distributed throughout Finland which has an area of 338 400 km^2.

Although only deep wells were used in this study as the HP heat source, it may be realistic that some deep wells would be replaced by other heat sources, such as air-to-water heat pumps, waste heat sources such as data centers, or conventional geothermal energy. However, unlike with geothermal heat, the variation of the outside air temperature has a considerable effect on the operation of the air-to-water HP.

5. Conclusion

The Finnish electricity and district heat generations were modeled with high penetration levels of renewable generation sources and thermal storage in 2050. The modeling considered four retrofits and a business-as-usual path for the building stock. If changes were only applied to either the building stock or the energy system, the emission reduction target of 1.827 Mt-CO_2, a 90 % reduction from the calculated 2020 reference, was never reached. However, when both were considered, the target was reached with various combinations of wind power, deep heat well heat pumps, and thermal storage capacity for each building stock retrofit scenario. Even though the reached emission-levels for each of the building stock scenario were close to each other, the costs were not. With a lower retrofit level for the buildings the target emissions were achieved with the cost of 10.2 and 11.3B€, compared to 23.6 and 25.5B€ when the buildings were retrofitted more extensively. Whereas whether the building stock developed more towards individual heat pumps or district heating, had a minor impact on the costs and emissions. The amount of wind power had a significant impact on the results, and in general the more wind power was utilized the less the other measures were required. The required capacity of wind power to reach the target level varied between 8640 MW and 12 960 MW depending on the building stock scenario. Dimensioning the DHWHPs to 30 % of the peak DH demand instead of 20 % reduced the emissions but increased the costs even more. As the capacity of wind power, DHWHPs, and thermal storage were increased the amount of energy generated with fossil fuels, here natural gas, decreased significantly, but the capacity of them did not. This highlights the high capacity demand of back-up generation, in both the electricity and DH generations, even with high penetration levels of emission free generation.

For the BAU scenario the highest emission reduction attained for year 2050 was 73 % (corresponding to 43 % over 30 years), and for the retrofit scenarios 95 – 96 % (63 – 66 %). The costs for these were 13.7B€, and 17.0 – 34.4B€, respectively. The lowest cost increase to reach the emission target was achieved when the building stock was renovated according to the DH Low retrofit scenario together with 12 960 MW of wind power capacity, DHWHPs limited to 20 % of the peak DH demand, and thermal storage capacity of 50 GWh. For this scenario the annual emissions were 1.82 Mt-CO_2 in 2050. The emissions over 30 years reduced from 488.0 Mt-CO_2 for a reference scenario to 217.0 Mt-CO_2, with a cost increase of 10.18B€. Thus, the unit cost of emission reductions was 37.6 €/t-CO_2.

Further studies are required to consider how the import and export of electricity would affect the energy system, as they could be utilized for further balancing of the supply and demand. In addition, the limitations of national electricity transmission and distribution networks should be considered. Moreover, as the CHP DH generation covers a large part of the current DH and electricity demands, it could be still incorporated as a generation source for a more realistic examination. However, the fuels used in the CHP DH could be changed, and for example, the possibility to utilize synthetic fuels should be studied, which could also be used by the CCGT generators and the fossil heat boilers. Moreover, other sectors of energy should be included, e.g., transport and industry, to examine how they would affect the overall system.

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CRediT authorship contribution statement

Ilkka Jokinen: Conceptualization, Methodology, Software, Formal analysis, Writing – original draft, Visualization. **Andreas Lund:** Conceptualization, Methodology, Software, Formal analysis, Writing – original draft, Visualization. **Janne Hirvonen:** Methodology, Writing – review & editing. **Juha Jokisalo:** Methodology, Writing – review & editing. **Risto Kosonen:** Writing – review & editing, Funding acquisition. **Matti Lehtonen:** Conceptualization, Methodology, Writing – review & editing, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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