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Environmental and economic assessment of borehole thermal energy storage in district heating systems

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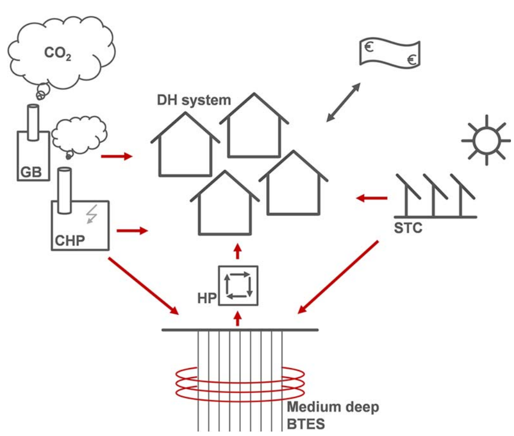
HIGHLIGHTS

- Economic and environmental LCA of medium deep BTES in DH generation is carried out.
- Various system compositions and changing boundary conditions are investigated.
- Pareto fronts illustrate optimal system designs with and without BTES.
- Economic and environmental assumptions affect optimal system designs considerably.
- Combinations of BTES, solar heat & a small CHP are competitive with CHP-based systems.

GRAPHICAL ABSTRACT



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ABSTRACT

District heating will play an important role for heat provision in temperate and cold climate zones in the future. However, in the context of decarbonizing the heating sector, conventional heat sources have to be replaced by renewable energies. This replacement correlates to the necessity to integrate the fluctuating energy source of solar radiation and thus requires seasonal thermal energy storage. More recently, borehole thermal energy storage systems have been integrated into such district heating concepts. Yet, the potential greenhouse gas emission reduction and the financial benefits of these innovative district heating concepts have not been assessed with respect to the environmental burden and the associated investment cost of the modernization. This study presents a comprehensive environmental and economic life cycle assessment of a fictional district heating system with varying shares of shallow to medium deep borehole thermal energy storage and alternative heat sources replacing conventional capacity. In an exemplary district heating system covering 25 GW h of annual heat demand, borehole thermal energy storage can decrease the greenhouse gas emissions of combined heat and power plants and solar thermal collectors by over 40%. Boundary conditions assumed for the development of the energy market and the existence of subsidies have a significant impact on the emission savings and the levelized cost of heat. Considering a probable increase of energy costs and a growing share of renewables in the electricity mix, a combination of solar thermal collectors and borehole thermal energy storage with a small heat and power plant is the best solution, which is economical even without subsidies. The results of the study promote the construction of medium deep borehole thermal energy storage systems that can help to increase the share of renewable energy in the heating sector at reasonable cost.

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Nomenclature

Abbreviations

BAU	business as usual scenario
BAU SUB	business as usual scenario including subsidies
BHE	borehole heat exchanger
BTES	borehole thermal energy storage
CHP	combined heat and power
DH	district heating
ECO	economic/environmental scenarios
EUA	European Union Emission Allowance
EU ETS	European Union Emissions Trading System
EVO	evolution scenario
EVO SUB	evolution scenario including subsidies
GB	gas boiler
GHG	greenhouse gas
HP	heat pump
LCA	life cycle assessment
P1 – P4	selection of Pareto efficient system designs
SI	supplementary information
STC	solar thermal collector
TES	thermal energy storage

Symbols

A_{STC}	solar collector area, [m^2]
CED	cumulative energy demand, [TJ]
L_{BHE}	length of borehole heat exchangers, [m]
N_{BHE}	number of borehole heat exchangers, [–]
α_{CHP}	coefficient of share of cogeneration in the peak load demand, [–]
EF	emission factor, [kg CO_2eq/kW h]
F	operation costs, [€]
GWP	global warming potential, [t CO_2eq]
I	investment costs, [€]
$LCOH$	levelized cost of heat, [€ct/kW h]
M	maintenance costs, [€]
P	thermal power demand/supply, [kW]
Q	thermal energy demand/supply, [kW h]
R	revenue, [€]
a	year of operation, [–]
r	interest rate, [–]

1. Introduction

By 2050, more than 80% of European residents are expected to live in urban areas [1]. Such populous areas are usually characterized by a high heat density and are therefore particularly suitable for the implementation of district heating (DH) grids. DH is considered an essential component in successfully transitioning to a sustainable and decarbonized heating sector (e.g. [2–6]). For this purpose, a large amount of fluctuating renewable energy sources must be integrated in future DH grids in order to replace conventional heat sources, while simultaneously guaranteeing the security of supply.

The concept of fourth generation district heating (4GDH, [7]) comprises a significant reduction of grid supply temperatures down to 55 °C [8]. Grid losses are thereby lowered and the energy and exergy efficiency is improved [8,9]. Moreover, low-carbon heat sources like geothermal energy or industrial waste heat, which are characterized by low-temperatures, can be integrated more efficiently (e.g. [10,11]).

Another auspicious technology for substituting fossil heat sources in DH grids is large solar thermal collector (STC) fields [12–14]. However, especially in the temperate and cold climate zones, there is a seasonal mismatch between solar supply and heat demand [15]. Seasonal thermal energy storage (TES) systems are able to offset this mismatch, thus increasing the performance of solar thermal heating systems [16] and reducing the required STC size [17].

There are several seasonal TES technologies available (for an overview see [18,19]). However, their requirements are diametrically opposed: high storage capacities are desired, but the costs and the space required need to be minimized [20]. With respect to heat storage on a district level, chemical and latent heat storage solutions are not competitive yet [19]. Only a couple of sensible heat storage technologies meet the requirements for large-scale TES. These can be differentiated into large above-ground water tanks and underground thermal energy storage (UTES) like water or gravel-water pit storage [21,22], cavern storage or aquifer storage [23,24]. Another promising type of UTES are borehole thermal energy storage (BTES) systems [25–27]. BTES utilizes the subsurface as a heat storage medium via a borehole heat exchanger (BHE) array. Even though initial costs are very high for BTES systems, specific costs in relation to the storage capacity are relatively low compared to other storage technologies [13,28]. The functionality of BTES has already been demonstrated in several projects (e.g. [12,29–34]). A basic overview of installed systems and their technology is given by Gehlin [26]. Recent studies propose the novel concept of medium deep BTES [35–40]. They can reach storage efficiencies of more than 80% [35]. Compared to shallow systems (usually < 100 m in depth), medium deep BTES consist of fewer but deeper BHEs (up to 1000 m). They require less floor area than shallow systems with a similar storage capacity and can significantly inhibit the thermal impairment of sensitive aquifers in the shallow subsurface [41]. Therefore, the utilization of medium deep BTES is more independent of the geological conditions and could lead to a more widespread application of seasonal heat storage. Nevertheless, deeper wellbores require more sophisticated and therefore more expensive drilling methods and the environmental impact of such systems has not been investigated yet. Consequently, uncertain financial implications and vague environmental benefits inhibit their market introduction.

Several studies deal with the optimization or the assessment of DH systems in terms of profitability and/or environmental impact. Most of these studies concentrate on specific technologies like heat pumps (HP) [42–44], combined heat and power (CHP) [5,45,46], the integration of industrial excess heat [47] or energy conservation measures [48–51]. Truong & Gustavsson [52] compare different DH production technologies under changing economic or environmental boundary conditions but do not include any TES in their considerations. Certainly, some valuable publications already address the integration of solar thermal technology into DH systems in combination with heat storage (e.g. [16,53–59]). But they either concentrate on specific case studies, look at economic or environmental impacts only or disregard potential changes in the economic or environmental boundary conditions. With a few exceptions (e.g. [60]), most studies assessing the environmental impacts of DH heat production only take into account the use phase. Tulus et al. [61] is the only study that combines an economic and environmental life cycle assessment (LCA) to optimize central solar heating plants including a seasonal TES. Their results show that optimally sized solar thermal storage systems can significantly reduce both costs and environmental impact, compared to a gas-fired boiler (GB). However, their case study did not consider the effects of changing economic and environmental boundary conditions. It lacks a combination of BTES with CHP as well as a comparison to CHP technology, which has a much higher relevance in future DH grids than GB. Furthermore, they only take into account water tank storages, which differ significantly in their behavior and economics from BTES systems.

Accordingly, a comprehensive study, comprising an economic and an environmental LCA of different heating concepts for DH systems under different economic and environmental boundary conditions, is missing. Moreover, the financial and environmental effects associated with the integration of BTES into district heating concepts have not been jointly addressed so far. Thus, we present a dedicated economic and environmental life cycle analysis of district heating concepts integrating shallow to medium deep BTES. Several BTES-assisted heat generation plant options for DH systems, including GB, CHP and STC, are assessed with respect to their levelized cost of heat (*LCOH*) and their global warming potential (*GWP*), and are compared against reference heat generation scenarios without seasonal TES. In addition to solar thermal energy, surplus heat from a CHP, which is usually driven in heat-match mode, is considered for BTES charging as well.

2. Methods

The economic and environmental impacts connected to district heating concepts that include medium deep BTES were evaluated for a synthetically generated district heating load profile with an annual heat demand of 25 GW h by conducting the following steps:

1. Definition of boundary conditions: Seven system combinations of the considered heat generation technologies were assembled for comparison of options (Fig. 1), including four combinations without any seasonal TES and three including a BTES system. To compare these seven technical combinations, four environmental and economic scenarios (ECO scenarios, Table 1) were developed.
2. Model implementation: based on the selected heat generation options, an integrated energy balance and economic/environmental assessment model was developed, which considers the various economic and environmental boundary conditions. The environmental burdens were ascertained in terms of an LCA.
3. Parameter study: the system components CHP, STC and BTES were varied in size and the economic and environmental effects of the generated variants for the four ECO scenarios were calculated. The analysis of the acquired data was performed in two consecutive steps: Firstly, an **identification of Pareto efficient system combinations and designs** was conducted. Secondly, a **case analysis** was carried out, in which a selection of four of the previously identified Pareto efficient system designs were compared in detail to demonstrate economic and environmental effects of seasonal TES against reference scenarios. They serve as a measure for the performance of the respective BTES-assisted heat generation plant design.
4. Sensitivity analysis: at the end, a comprehensive sensitivity study was carried out on the four selected heat generation systems in order to determine the influence of different variables on the *LCOH* of the four selected Pareto efficient system designs.

As the following subchapters can only give a summary of these steps, much of the detailed information has been omitted. However, more on the methodology is given in the attached supplementary information (SI) file (Appendix A).

Table 1
Economic and environmental scenarios.

Scenario	Gas price [ct/kW h]	Electricity price for CHP feed-in [ct/kW h]	Electricity price for industry [ct/kW h]	Emission factor grid electricity [g/kW h]	Subsidies included
BAU	3.08[a]	3.66[b]	13.08[c]	532[d]	
BAU SUB	3.08[a]	3.66[b]	13.08[c]	532[d]	✓
EVO	Projected[e] (4.59)	Projected[e] (6.59)	Projected[e] (14.34)	Projected[f] (322)	
EVO SUB	Projected[e] (4.59)	Projected[e] (6.59)	Projected[e] (14.34)	Projected[f] (322)	✓

[a] Average gas price for industry in Germany 2015 [64].
[b] 3.16 ct/kW h average price for baseload power at the European Power Exchange EPEX spot 2015 [65] plus 0.5 ct//kW h for avoided grid charges.
[c] Average value for 2015 [64].
[d] Current German electricity mix [62].
[e] 30 year time series starting at BAU value and ending at the given value in brackets, based on [63], (see SI 2).
[f] 30 year time series starting at BAU value and ending at the given value in brackets, determined according to [62], (see SI 2).

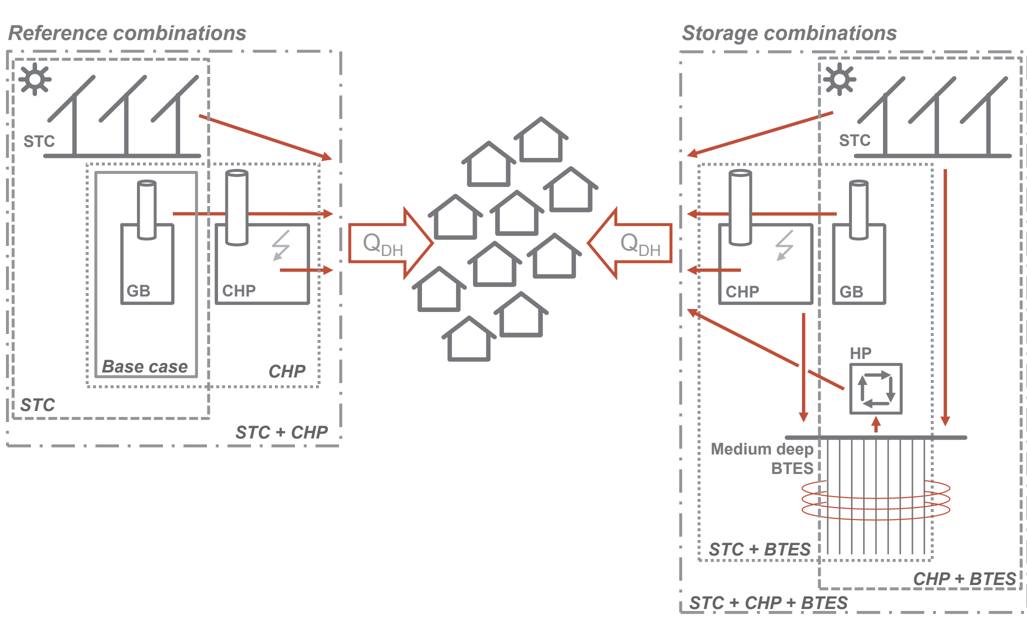

Fig. 1. Technical reference and storage scenarios.

2.1. Boundary conditions

2.1.1. System components and combinations

As a basic assumption, a DH system with a GB was considered. The DH grid was not specified in detail. It was only represented by a synthetically generated hourly heat load demand curve with an annual heat demand of 25 GW h (see also Section 2.2.1) and a constant supply temperature of 55 °C. Seven different combinations (Fig. 1) consider the partial replacement of the GB's heat supply capacity with the following three components and their combinations: a CHP, an STC field and a medium deep BTES, which is assisted by a heat pump (HP). In the first three system combinations, the heat demand was satisfied without any seasonal TES. These combinations represent the heat generation in conventional district heating systems, whereas the latter three combine the respective conventional heat generation options with a HP-assisted BTES. The size of the individual components CHP, STC and BTES in the respective combinations may vary in size, influencing the outputs significantly. However, all system combinations still comprise a GB, which is dimensioned to cover the residual load and providing back-up capacity. The HP, which is connected to the BTES system, was sized according to the capacity of the storage. It is needed to yield the required grid supply temperature from the BTES.

2.1.2. Environmental and economic scenarios (ECO scenarios)

To fulfill the life cycle approach, the environmental burdens and costs of the production (for more details see Sections 2.2.2 and 2.2.3) and use phase of the identified components were evaluated. During the use phase, several assumptions regarding prices and the electricity mix influence the results. Therefore, two of the four ECO scenarios investigated the effects of steady prices and emission factors (business as usual, BAU scenarios) in comparison to a hypothetical price development and the projected reduction of the grid electricity emission factor due to an expected increasing share of renewables in the grid mix (evolution, EVO scenarios).

Since circumstances vary from country to country, it was not possible to define boundary conditions, which are universally valid. Due to the good data availability, the ECO scenarios in this study are based on the German energy environment.

2.1.2.1. BAU scenario. In the BAU scenario (see also Table 1) a constant gas price of 3.08 ct/kW h was assumed, whereas the CHP-produced electricity can be sold to the grid for 3.66 ct/kW h. If the system combination lacks a CHP, external electricity has to be purchased, which is charged with an electricity tariff for industry of 13.08 ct/kW h. As the CHP replaces existing electricity production, the CO_2 emissions of the cogenerated electricity were derived from the *Gemis 4.93* database [62] considering the current German electricity mix.

2.1.2.2. EVO scenario. Based on the predictions by Schlesinger et al. [63], the EVO scenario anticipates a development of the prices and the German electricity mix. The respective CO_2 emission factors were determined according to *Gemis 4.93* [62]. A figure showing the assumed time series of the annual energy prices and the emission factor of the electricity mix is provided in the supplementary (see SI 2).

2.1.2.3. BAU SUB & EVO SUB scenarios. Germany offers several state subsidies for the deployment of CHPs, renewable energies and TES that can be exploited. Therefore, these subsidies were taken into account in two sub-scenarios (BAU SUB & EVO SUB) complementary to the other ones (Table 2).

Costs for European greenhouse gas (GHG) emission allowances (EUA) were not factored in, since the *European Union Emissions Trading System* (EU ETS) only applies to combustion plants exceeding a rated thermal input of 20 MW, which is clearly beyond the regarded system size.

Table 2
Subsidies considered in scenarios BAU SUB and EVO SUB.

System	Public funding line	Amount
CHP	German Act on Combined Heat and Power (KWKG 2016) [66]	Continued support of 30,000 full load hours: 3.1 Cent per kW h of electricity sold to the grid
BTES	German Act on Combined Heat and Power (KWKG 2016) [66]	30% of investment cost
STC	KfW (German Promotional bank) program: "Renewables Energy Premium" (KfW 2016) [67]	Investment support: 40% of investment cost

2.2. System modelling

The heating system analysis required a model (Fig. 2) that calculates the system response based on the size of the different components (system design). For each system design, the system response was evaluated in terms of costs and environmental effects according to the underlying ECO scenario. Since the DH grid itself is assumed to be identical for all system designs, it was excluded from the assessment. In the following, the three steps of the assessment are explained in detail.

2.2.1. Heating system model

The DH system was modeled on the basis of an energy balance calculation, which was implemented in MATLAB 2016 [68]. It considers an urban quarter with 40% single family homes, 40% multi-family homes and 20% commercial buildings. Ambient temperature data from a test reference year dataset of Germany (BBR [69], medium weather conditions, region 12) were used to generate an hourly heat load curve with a total annual heat demand $\boldsymbol{Q_{DH}}$ of 25 GW h for a 30 year valuation period (see supplementary information SI 1).

The design of the heat generation system is defined by three input variables:

- Size of the CHP, characterized by the coefficient of share of cogeneration $\boldsymbol{\alpha_{CHP}}$
- Size of the STC field, characterized by the collector area $\boldsymbol{A_{STC}}$
- Size of the BTES, characterized by the length $\boldsymbol{L_{BHE}}$ of the BHEs, while the number $\boldsymbol{N_{BHE}}$ of BHEs is kept constant at 37[1].

Based on these parameters, the required sizes of the GB and the HP were determined automatically, always guaranteeing to supply the 25 GW h of heat.

For every hour of the simulation period the heat balance was calculated according to the supply and demand curves. The balance equations (see SI 3) define, whether a component of the system is producing heat or not and whether the seasonal storage system is charged or discharged. An explicit order of priority for the feed-in of different heat sources into the DH grid was predefined: if available, solar thermal energy has priority over cogenerated heat. This ensures that the most environmentally friendly heat is utilized first. Then cogenerated heat, which has a higher exergy, is favored over the low exergy heat from the storage system. Ultimately, excess production of cogenerated heat and heat from the GB has to be avoided. Consequently, these systems may have to operate in partial load.

The hourly values of the thermal power $\boldsymbol{P}$ of each technology are determined in the energy balance model and are used to determine the hourly natural gas consumption of these technologies as well as the electrical power output of the CHP. Furthermore, the auxiliary electricity (for example, for the operation of circulation pumps and the heat pump) is determined according to either the components' size or the

[1] The number of 37 BHEs originates from a circular alignment of the BHEs (cf. Welsch et al. [12]).

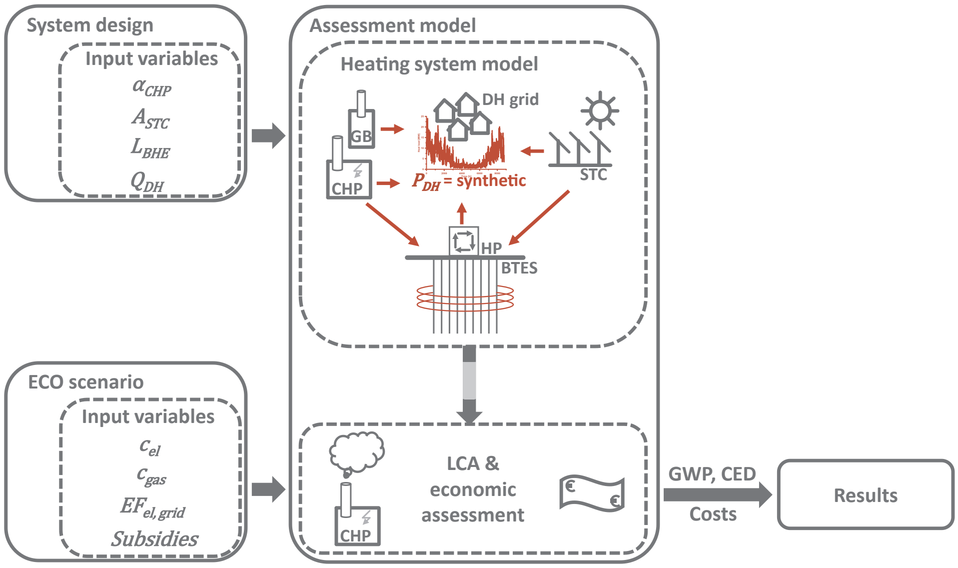

Fig. 2. Schematic illustration of the assessment model.

power values. Detailed information about the modelling of the system components, the calculation of the energy consumption and supply of each technology is given in SI 3. Additional references and datasets that are used in the heating system model are listed in Table 3.

The cost analysis and the LCA were based on annual energy amounts. For this purpose, the sum of the respective hourly power values for each system component or energy source $\boldsymbol{P}$ provides the annual energy amounts $\boldsymbol{Q_a}$:

$$Q_a = \int P dt \quad (1)$$

2.2.2. Economic assessment

The economic output of the system configurations was compared using the approach of *LCOH* (cf. [70,71]). The *LCOH* represents the financial mathematic average for the specific cost of heat in euro cent per Kilowatt-hour over the assumed valuation period $\boldsymbol{a_{end}}$. It was calculated from the net present value, which consists of the investment costs $\boldsymbol{I}$, maintenance costs $\boldsymbol{M}$, operation costs $\boldsymbol{F}$ (i.e. fuel/electricity costs), the revenue $\boldsymbol{R}$ of the system and the assumed interest rate $\boldsymbol{r}$, and is divided by the system's discounted thermal energy output $\boldsymbol{Q}$:

$$LCOH = \frac{\sum_{a=0}^{a_{end}} (I_a + M_a + F_a - R_a)\cdot(1+r)^{-a}}{\sum_{a=0}^{a_{end}} Q_a\cdot(1+r)^{-a}}\cdot 100 \quad (2)$$

Investment costs only arise at the beginning $\boldsymbol{a} = 0$. If the valuation period $\boldsymbol{a_{end}}$ exceeds a component's lifetime, the respective investment cost can occur more than once. In return, a residual value was deducted at the end, if the period under consideration is exceeded by a component's lifetime. Detailed information about the cost elements of the various system components and their calculations can be found in SI 4. Further references and datasets that are used in the economic analysis are listed in Table 3.

2.2.3. Life cycle assessment

The environmental impact of DH systems is composed of GHG emissions during the operation, and also related environmental effects during the production and the implementation of system components as well as their disposal. LCA, as specified in the standards ISO 14040/44 [72,73], is a method for weighting the environmental effects of product systems. In this study, the OpenLCA software [74] was employed to compile the environmental effects resulting from the production process of the regarded system components. For this purpose, the following databases were incorporated: *ecoinvent 3.1 cutoff* [75], *GaBi 5* [76] and *Gemis 4.93* [62].

2.2.3.1. Goal and scope definition. The LCA conducted within this study allowed for a comparison of environmental burdens of different district heating concepts. In this context, the functional unit was defined as 25 GW h heat annually delivered to the DH grid for 30 years. It was assumed that the DH system is located in Germany. Transportation of goods was only considered in terms of raw material transport, which has already been taken into account in the applied datasets. Transportation from the production site to the buildings was not included as it is expected to have only a minor effect on the overall results. Aside from that, the disposal phase (end-of-life) of the components was disregarded as well. This is a common practice in many LCA: firstly, it is assumed that the impact of the disposal phase is negligible compared to the production and use phase, and secondly, recycling processes may advance and are therefore difficult to predict. Another argument for this approach is that subsurface installations of BTES systems have a much longer life than 30 years, and reliable data about the dismantling of BTES is not available yet.

2.2.3.2. Life cycle inventory (LCI) and impact assessment (LCIA). Initially, several datasets were compiled, which describe the environmental impacts connected to the production phases of the respective system components. Subsequently, the applicability of this

Table 3
Further datasets and references applied in the three submodels of the assessment tool sorted by the respective system component.

	Heating model	Economic model	LCA	
			Production	Use Phase
STC	[68,69,78]	[79]	[75,79]	[62]
CHP	[80–82]	[80]	[75]	[62]
BTES	[35]	[83]	[75,83]	[62]
HP	[84]	[85]	[75,86]	[62]
GB		[87]	[75]	[62]

data was evaluated. Finally, suitable datasets were adapted for our approach. They were normalized to either the nominal power (CHP, GB, HP) or the size (STC, medium deep BTES) of the respective component in order to facilitate the inclusion of the LCA data into the assessment tool. The environmental impact during the use phase essentially results from natural gas combustion and electricity consumption. Therefore, these burdens are assessed on the basis of the gas and electricity consumption of the respective system component.

The midpoint impact category of global warming potential (*GWP*) according to CML 2001 [77] was chosen to evaluate the environmental burdens. In addition, the cumulative energy demand (*CED*) was appraised. However, the focus was set to the *GWP*, as the differences between *GWP* and *CED* are only marginal in the systems assessment. Additionally, the emission factor (*EF*) $\left[\frac{kgCO_2eq}{kWh}\right]$ was evaluated to allow for comparison with differently sized systems. The *EF* is defined as the ratio of summarized *GWP* values for production and operation of each component and the overall heat production of the according system:

$$EF = \frac{GWP}{Q_{th,tot}} = \frac{1}{Q_{th,tot}} \cdot \sum_{i=1}^{n} \left(GWP_{prod,i} + \sum_{a=1}^{a_{life}} GWP_{a,op,i} \right) \tag{3}$$

Detailed information about data sources and handling as well as the calculation of the environmental impact of the different system components is given in SI 5. References and datasets used in the LCA are listed in Table 3.

2.3. Parameter study

The three technical components CHP, STC and BTES were varied in size and combined to a full factorial experimental design, as illustrated in Table 4, resulting in 9241 different system designs. For each of these system designs the *LCOH* and the *GWP* were calculated (Fig. 4).

The analysis of the results is divided into two steps (see also Fig. 3):

- Identification of Pareto efficient system designs
- Case analysis

In the first step, the best of the sampled system designs were determined for each configuration and ECO scenario. Subsequently, selected optimal designs were compared across different ECO scenarios in order to illustrate advantages and disadvantages of the integration of medium deep BTES into DH concepts under various boundary conditions.

2.3.1. Identification of Pareto efficient system combinations & designs

The search for an optimal system design represents a multi-objective optimization problem, composed of two generally independent objective functions. More specifically, the most economic heating supply system is usually not the system with the lowest global warming potential. Instead, several Pareto efficient solutions exist. Each of them represents a system design, for which neither the *GWP* nor the *LCOH* can be improved without impairing the other. Thus, the first step deals with the identification of Pareto efficient system designs for all scenarios and combinations under consideration.

28 different sets of Pareto efficient system designs can be identified for the relevant combinations of the seven technical configurations and the four ECO scenarios. Three characteristic Pareto efficient system designs were identified for each of the sets where possible (for some, optimization resulted in a single optimal solution). These subsets consist of the system designs with the minimum *LCOH*, the minimum *GWP* and a compromise solution.

The former two represent the Pareto efficient solutions to the multi-objective optimization problem:

$$\begin{aligned}
&\min_{L_{BHE}, A_{STC}, \alpha_{CHP} \in R} \quad LCOH\,(L_{BHE}, A_{STC}, \alpha_{CHP})\\
&\min_{L_{BHE}, A_{STC}, \alpha_{CHP} \in R} \quad GWP\,(L_{BHE}, A_{STC}, \alpha_{CHP})\\
&\text{subject to}\\
&0 \leqslant L_{BHE} \leqslant 1000\\
&0 \leqslant A_{STC} \leqslant 100{,}000\\
&0 \leqslant \alpha_{CHP} \leqslant 1
\end{aligned} \tag{4}$$

The compromise solution is defined as the point, where the reduction of *GWP* equals the increase of the *LCOH*. It represents a system design, which achieves a relatively large reduction in the *GWP* associated with only a moderate increase in the *LCOH*.

2.3.2. Case analysis

A selection of compromise solutions for four specific system combinations labeled P1–P4 was chosen for a detailed analysis and comparison of the environmental and economic effects induced by BTES systems (Table 5). The Pareto efficient system identification (see Section 3.1.1) revealed that BTES systems are most favorable when assuming progression scenarios (EVO & EVO SUB). However, subsidies are a regional regulatory procedure that manipulates the results to some extent. For this reason, the four cases, P1 to P4, were selected from the compromise solutions of EVO (see Table 6). The case analysis comprises a comparison of all ECO scenarios on the example of these four system designs. It should be noted that they are not necessarily Pareto optimal designs in a scenario other than EVO.

P1 consists of a CHP (α_{CHP} = 35%) and a GB representing a conventional DH system. P2 illustrates the effects of adding an STC field with an area of 20,000 m^2 to P1. P3 and P4 both consider a medium deep BTES system for seasonal storage of STC heat. P3 additionally includes a small CHP with α_{CHP} = 5% for self-supply of electricity.

Table 4
Variation of the technical input parameters.

	α_{CHP} [%]			A_{STC} [m^2]			L_{BHE} [m]			n
	Range		Interval	Range		Interval	Range		Interval	
	Min	Max		Min	Max		Min	Max		
GB-only	0	0	–	0	0	–	0	0	–	1
CHP	5	100	5	0	0	–	0	0	–	20
STC	0	0	–	5000	100,000	5000	0	0	–	20
CHP + STC	5	100	5	5000	100,000	5000	0	0	–	400
CHP + BTES	5	100	5	0	0		0	1000	50	400
STC + BTES	0	0	–	5000	100,000	5000	0	1000	50	400
CHP + STC + BTES	5	100	5	5000	100,000	5000	0	1000	50	8000
									Sum	9241[a]

[a] The 20 system designs consisting of a GB and a BTES were removed, as the combination of a GB and a BTES system is illogical from an energetic, environmental and economic point of view.

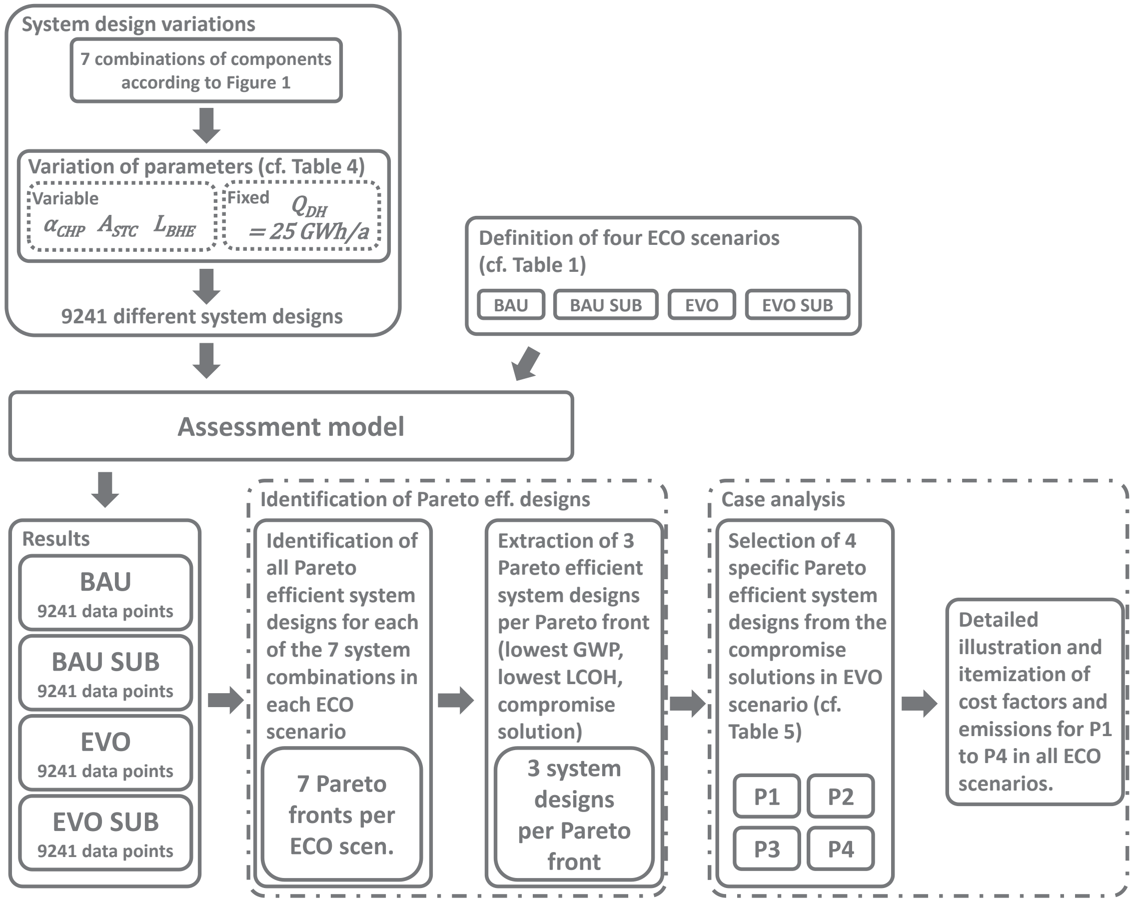

Fig. 3. Schematic illustration of different steps of the parameter study.

2.4. Sensitivity analysis

Finally, the influence of the most important cost factors on the *LCOH* was assessed in a sensitivity analysis to give an estimate of the uncertainty of the results. It was carried out as an OAT (one-at-a-time) analysis in which one single parameter was varied after another with reference to a base case. It assessed the influence of the investment costs, the energy costs and the interest rate on the *LCOH*. The BAU scenario was taken as a basis and the sensitivity was evaluated for the selected compromise solutions of the system configurations determined before (P1–P4).

3. Results

3.1. Parameter study

In the different technical combinations[2] and ECO scenarios under consideration, the *LCOH* ranged from approximately 3.6 ct/kW h (assuming BAU SUB) to almost 10.43 ct/kW h (expecting EVO) (Fig. 4). The total *GWP* for the production phase and 30 years of operation varied between 67,000 t CO_2eq and 215,000 t CO_2eq, mostly depending on the technical scenario and the size of the subsystems (Fig. 4). This corresponds to an average emission factor *EF* of 90 g CO_2eq/kW h to 290 g CO_2eq/kW h. These variations in heat price and GHG emissions illustrate that the economic and environmental evaluation of district heating concepts is highly sensitive to the system design as well as the economic-environmental assumptions made.

[2] All system combinations comprise a GB, which covers a certain share of the heat load. Therefore, the GB is not further mentioned when referring to system combinations.

3.1.1. Identification of Pareto efficient system combinations

Fig. 5 displays the Pareto fronts of the six different system combinations and the base case, which are presented for the four ECO scenarios. Table 6 summarizes the respective compromise solutions of the system combinations. The system designs identified as lowest *LCOH* and lowest *GWP* systems are summarized in SI 6.

3.1.1.1. GB-only. The GB-only base case was invariant and therefore does not constitute a Pareto front. It always obtained the highest *GWP*. As investment costs are relatively low for the GB, the *LCOH* depend mainly on the gas price. As a result, the GB achieved the lowest *LCOH* in BAU. Without any energy price development, other technologies only become competitive if subsidies are introduced (BAU SUB). In EVO and EVO SUB the *LCOH* for the GB rose with the predicted increase of energy costs.

3.1.1.2. CHP. Replacing GB capacity with a CHP led to a significant reduction of the GHG emissions of up to 54%. These relatively large emission savings are attributed to the high CO_2-credits for replacing electricity in the grid by cogenerated electricity. In BAU the compromise solution with $\alpha_{CHP} = 50\%$ can reduce the *GWP* by almost 53% compared to the base case. However, the reduction of the *GWP* was also associated with rising *LCOH*. With an increasing share of renewables, emission factors of the grid electricity were expected to fall resulting in an impairment of the CO_2-credits associated with the replacement of grid electricity in EVO/EVO SUB. Additionally, an expected increase of the gas price also effected the *LCOH*. Subsidies reduced the *LCOH* below the base case and collapsed the Pareto fronts to a single optimum solution with $\alpha_{CHP} = 55\%$ (BAU SUB and EVO SUB).

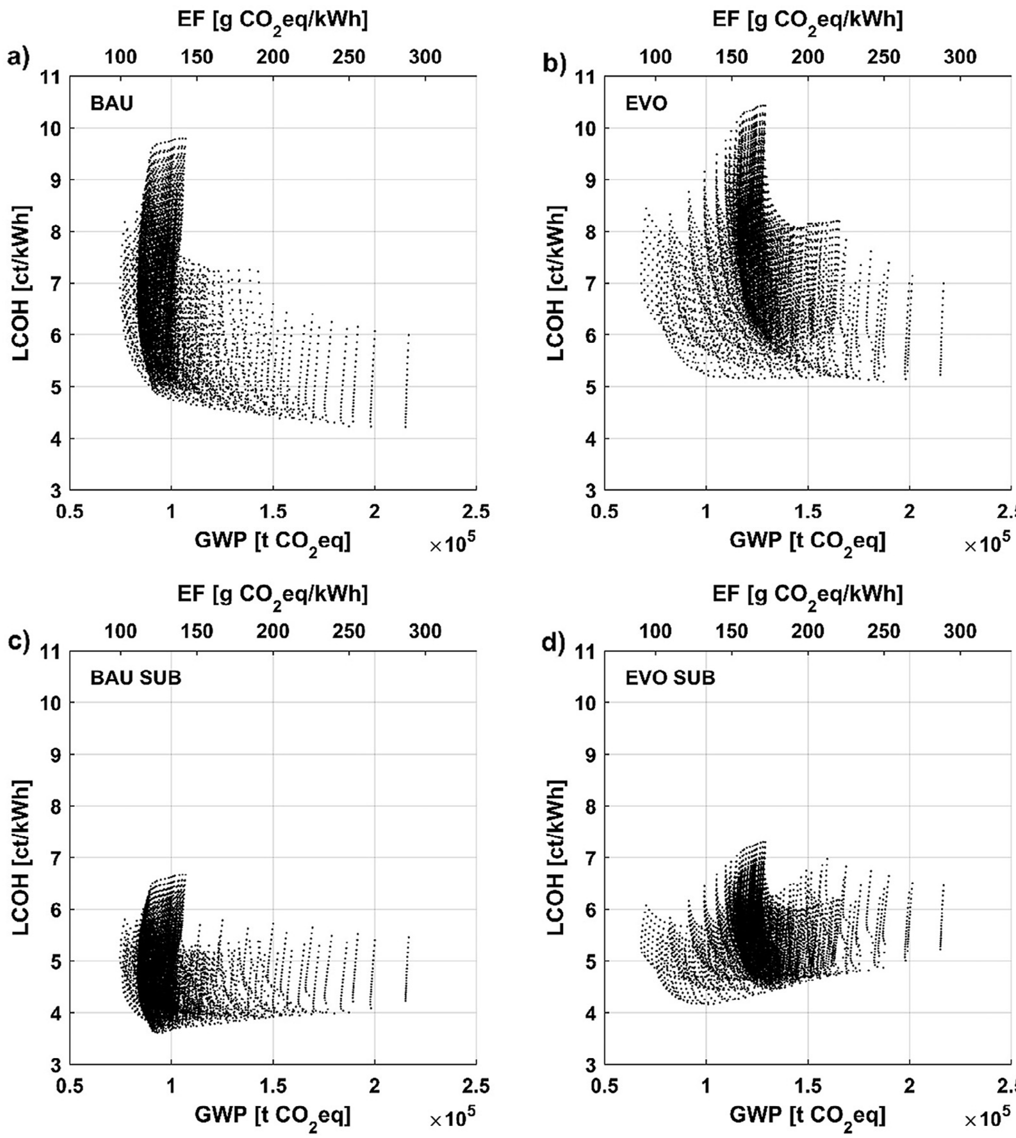

Fig. 4. Total range of *LCOH* and *GWP* for the four ECO scenarios.

Table 5
System combinations chosen for the detailed case analysis.

No	Combination	Share of cogeneration [–]	STC area [m²]	BHE length [m]
P1	CHP (+GB)	0.35	0	0
P2	CHP + STC (+GB)	0.35	20,000	0
P3	CHP + STC + BTES (+GB)	0.05	45,000	650
P4	STC + BTES (+GB)	0	55,000	750

3.1.1.3. STC. Replacing GB capacity with STC can also reduce the *GWP* markedly. Emissions from STC originated from the electricity required for operation, but also to a great extent from the production. Considering an increasing share of renewables in the grid electricity mix, the reduction potential can even exceed CHP systems, if the STC field is large enough (EVO and EVO SUB). However, STC entail high specific investment costs and the heat production of large STC systems exceeds the heat demand during the summer months. Thus, the *LCOH* increased over-proportionately compared to the achieved reductions in the *GWP*. Subsidies can attenuate the effect (BAU SUB and EVO SUB), but even so, large STC become the most expensive solution. Nevertheless, small STC fields can provide economical *GWP* reductions even without subsidies (BAU and EVO).

3.1.1.4. CHP + STC. In all ECO scenarios, the combination of STC and CHP amplified the reduction of the *GWP* and the *LCOH* with regard to a separate replacement of GB capacity. Due to the aforementioned exponential increase of *LCOH* with STC share, the Pareto optimal systems consist of moderately sized CHP and small-sized STC. An increasing share of renewables in the grid electricity mix and the associated impairment of the CO_2-credits for CHP (EVO and EVO SUB) allowed for slightly larger STC fields (Table 6). Where subsidies were considered (BAU SUB & EVO SUB), the *LCOH* for almost all Pareto optimal CHP + STC systems were competitive compared to the base case: in BAU SUB, the CHP + STC system with α_{CHP} = 45% and A_{STC} = 10,000 m^2 even yields the overall lowest *LCOH* of 3.6 ct/kW h with a *GWP* reduction of 56%.

Table 6
Heating system compositions with the compromise solution between lowest *LCOH* and lowest *GWP* for different technical and economical/environmental scenarios.

		GB-only	CHP	STC	CHP + STC	CHP + BTES	STC + BTES	CHP + STC + BTES
BAU	α_{CHP} [–]	0.00	0.50	0.00	0.45	0.50	0.00	**0.05**
	A_{STC} [m^2]	0	0	10,000	10,000	0	50,000	**40,000**
	L_{BHE} [m]	0	0	0	0	50	650	**550**
	LCOH [ct/kW h]	4.22	4.86	4.23	4.81	5.00	5.50	**4.77**
	GWP [t CO_2eq]	215,246	101,352	187,423	95,685	100,518	94,852	**98,362**
BAU SUB	α_{CHP} [–]	0.00	0.55	0.00	**0.55**	0.55	0.00	0.50
	A_{STC} [m^2]	0	0	25,000	**10,000**	0	55,000	10,000
	L_{BHE} [m]	0	0	0	**0**	50	700	50
	LCOH [ct/kW h]	4.22	3.68	4.03	**3.62**	3.75	4.37	3.69
	GWP [t CO_2eq]	215,246	100,086	169,451	**92,153**	99,424	87,919	92,305
EVO	α_{CHP} [–]	0.00	*0.35*	0.00	*0.35*	0.40	*0.00*	***0.05***
	A_{STC} [m^2]	0	*0*	15,000	*20,000*	0	*55,000*	***45,000***
	L_{BHE} [m]	0	*0*	0	*0*	50	*750*	***650***
	LCOH [ct/kW h]	5.23	*5.75*	5.13	*5.69*	5.95	*6.13*	***5.37***
	GWP [t CO_2eq]	215,246	*157,422*	179,943	*133,759*	154,300	*79,204*	***92,767***
EVO SUB	α_{CHP} [–]	0.00	0.55	0.00	0.50	0.55	0.00	**0.05**
	A_{STC} [m^2]	0	0	35,000	25,000	0	55,000	**50,000**
	L_{BHE} [m]	0	0	0	0	50	800	**750**
	LCOH [ct/kW h]	5.23	4.68	4.84	4.51	4.76	4.81	**4.27**
	GWP [t CO_2eq]	215,246	151,473	160,671	126,703	151,447	76,845	**86,660**

Bold print highlights the technical system composition with the optimal solution for the respective ECO scenario. Italics denote the Pareto efficient combinations P1–P4 selected for the case analysis (see Table 5).

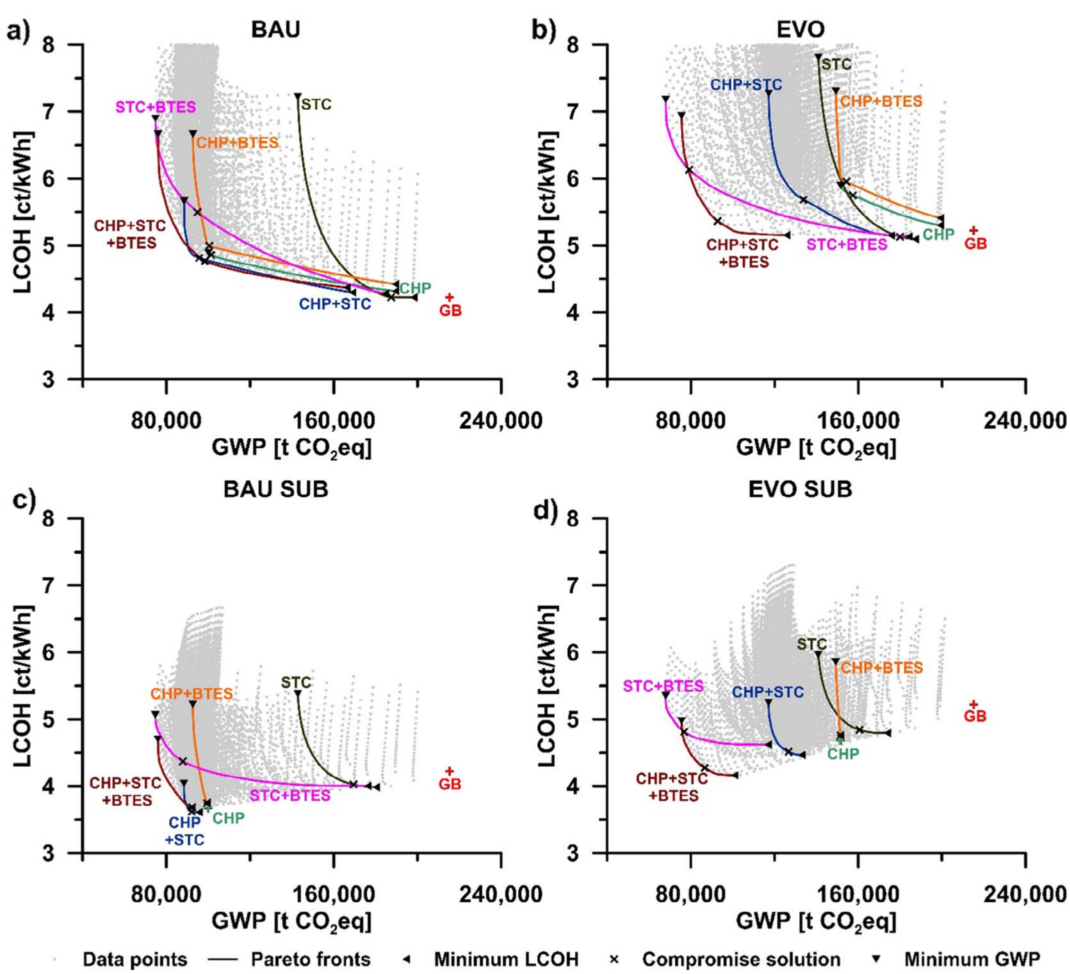

Fig. 5. Comparison of Pareto fronts for the different system compositions for (a) scenario BAU, (b) scenario EVO, (c) scenario BAU SUB and (d) scenario EVO SUB.

3.1.1.5. CHP + BTES. Adding a BTES to the CHP yielded almost no benefits regardless of the considered ECO scenario. Acting as a heat sink, the storage prolonged the running time of the CHP during the summer season, while it provided heat during winter time replacing GB capacity. However, the functional interaction of a heat-matching CHP and a BTES is complex (see Fig. 6a and b): a CHP that is too small does not provide enough thermal energy in summer to charge the storage appropriately, whereas a larger CHP shortens the discharge period and thus restrains the heat provision of the storage. Both cases resulted in inefficient storage operation. Subsequently, the earnings by an increased electricity production were too low to compensate for the high investment costs of the BTES, even when subsidies were taken into account. Hence, any CHP + BTES design was more expensive than the Pareto optimal CHP-only systems and *GWP* reductions attributed to the BTES were characterized by a steep increase in *LCOH* (see Fig. 5a and b). Furthermore, storage losses canceled out the CO_2-credits for replacing grid electricity rendering the reduction of GHG emissions almost insignificant.

3.1.1.6. STC + BTES. In contrast to the fossil fuel burning CHP, STC operation is almost emission-free (see above). Instead of adding a medium deep BTES to CHP, the combination with an STC field therefore entails a strong *GWP* reduction in both BAU and both EVO scenarios. An STC area of $\boldsymbol{A_{STC}} = 70{,}000\ \mathrm{m}^2$ and a BTES with a depth of $\boldsymbol{L_{BHE}} = 1000\ \mathrm{m}$ was the environmentally best system design across all ECO scenarios with the lowest *GWP* of 74,000 t CO_2eq and 68,000 t CO_2eq for BAU/BAU SUB and EVO/EVO SUB, respectively. This corresponds to a reduction of approximately 65% and 68% compared to the base case. The remaining GHG emissions can be attributed to the production and the electricity required for operation, and the GB, which covers the peak load.

Fig. 6c and d illustrate the synergies of STC and BTES systems. Due to the residual heat demand in summer, collector fields that were too small could not generate surplus heat to charge a BTES system. Thus, the integration of storage was only reasonable for solar thermal systems exceeding a critical size (approximately 15,000 m^2 in this particular case). Then, the integration of a medium deep BTES reduced costs and GHG emissions. Therefore, the capacity of both components had to be

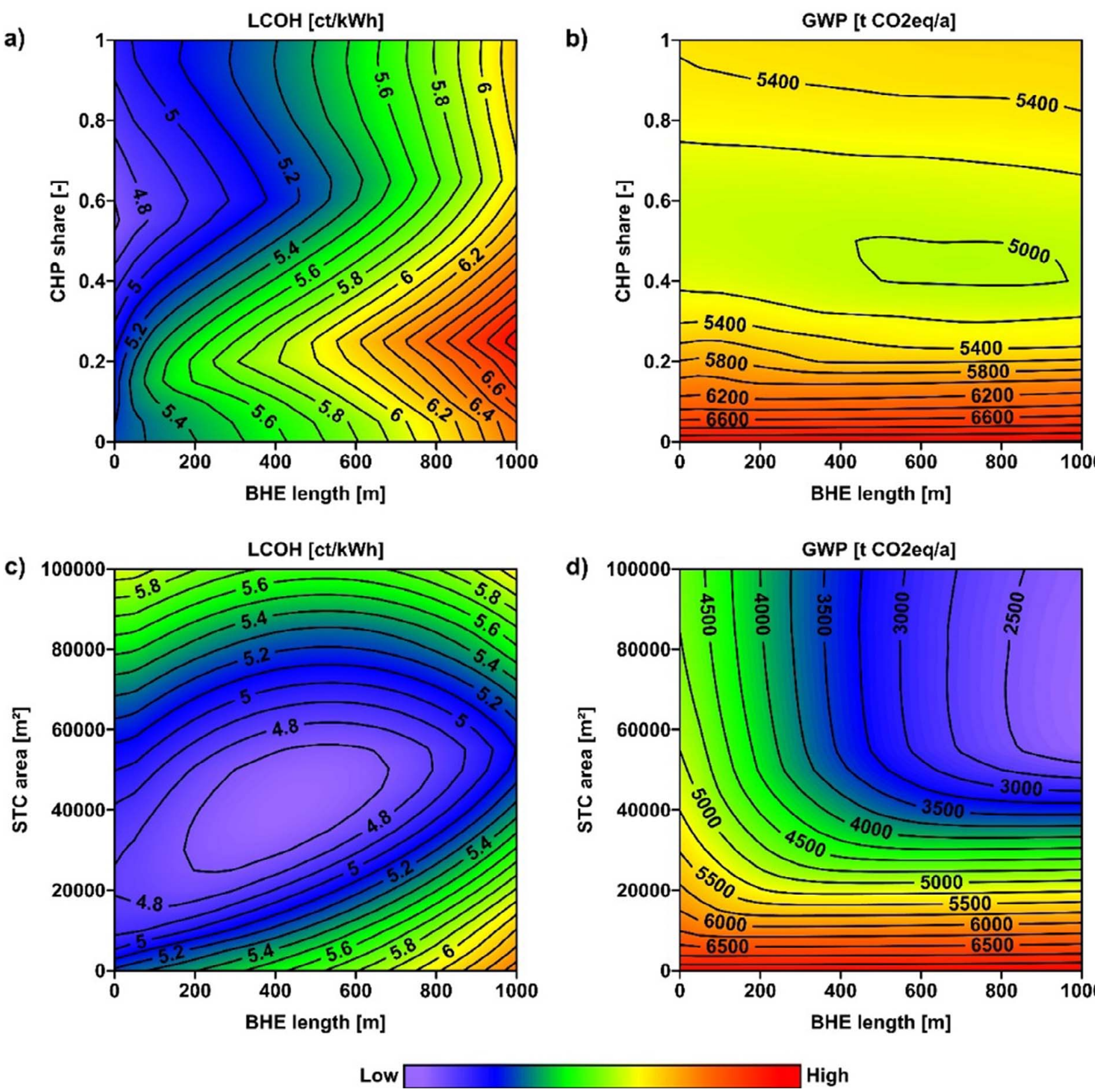

Fig. 6. Influence of the CHP share and the BHE length on the (a) *LCOH* and (b) *GWP*, influence of the STC area and BHE length on the (c) *LCOH* and (d) *GWP*, exemplary for the EVO scenario.

carefully balanced in order to maximize synergies. An oversizing of the STC or the medium deep BTES led to an increase of costs. Consequently, there is a global minimum in *LCOH* for a specific system combination (Fig. 6c) and only a simultaneous increase of the components' size allowed for an additional reduction of the *GWP* (Fig. 6d).

3.1.1.7. CHP + STC + BTES. STC + BTES systems still require a power supply for operation. Adding a small CHP to the STC + BTES combination allowed for the use of self-supplied electricity, which lowered the *LCOH* significantly in all ECO scenarios without straining the *GWP* too much (Fig. 5a–d). Accordingly, Pareto optimal designs typically had a CHP share just sufficient to cover the electricity demand for BTES and STC operation. Only in BAU SUB, subsidies for CHPs had a sufficient effect to allow for a share of α_{CHP} = 50%. Diminishing CO_2-credits for replacing grid electricity in the EVO scenario prohibited large CHP shares, even with subsidies (EVO SUB).

Compared to Pareto optimal CHP + STC designs, the CHP + STC + BTES systems exhibited a comparable *GWP* and *LCOH* in BAU and BAU SUB. In BAU, they even constituted the compromise solution with a slight advance. As high shares of CHP became less attractive with increasing energy costs and decreasing CO_2-credits, the replacement of CHP capacity by STC and BTES with a residual CHP share for self-supplied electricity became more favorable. Thus, CHP + STC + BTES systems represent the best solution in the EVO and EVO SUB scenarios (Table 6).

3.1.2. Case analysis

As subsidies take no effect on the environmental impact, the environmental assessment only considered BAU and EVO. For the economical assessment, the selected cases were analyzed under consideration of all ECO scenarios. This means they are not necessarily Pareto optimal designs in a scenario other than EVO.

The fractions of thermal energy supplied to the DH grid by the different system components for the four cases are displayed in Fig. 7 (averaged over 30 years of production). Although the CHP in case P1 has a share in the peak load demand of α_{CHP} = 35%, it contributes almost 83% of the total heat production. In case P2, the solar thermal energy covers approximately 22% of the annual heat demand. It mainly replaces cogenerated heat, while the share of the GB is only reduced by approximately 2.5 percentage points. In P3, 72% of the annual heat demand can be covered by the BTES-assisted STC field. Approximately 9 percentage points account for the auxiliary power for the HP, resulting in a solar fraction of approximately 63%. The CHP contributes 10% of the annual heat production leaving 18% to be covered by the GB. Sparing self-supplied electricity in case P4 allowed for a larger STC field and a larger BTES to substitute the heat production of the CHP, which increased the combined STC + BTES + HP share to 82% and the solar fraction to 76%.

3.1.2.1. Environmental effects. Generally, the share of solar thermal energy increased from P1 through P4. In BAU, this resulted in a perceptible decrease of the total *GWP* (Fig. 8a): while the integration of an STC field in P2 led to a reduction from approximately 113,000 t CO_2eq to 101,000 t CO_2eq by approximately 11%, adding a BTES in P3 reduced the *GWP* by another 9% to approximately 91,000 t CO_2eq. *GWP* savings of a markedly reduced CHP capacity were mostly equalized by the increase of emitted CO_2-equivalents of the auxiliary systems (GB, HP & circulation pumps for STC and BTES). Sparing the CHP altogether did not require additional GB capacity, but could be replaced by a larger STC field and a larger BTES. Thus, P4 allowed for an additional decrease of the *GWP* of 6% down to 85,500 t CO_2eq compared to P3. In total, the *GWP* declined by 24% from P1 through P4.

In EVO, the decreasing CO_2-credits for cogenerated electricity scaled up the *GWP* of CHP-provisioned heat. This amplified savings resulting from the replacement of CHP capacity (Fig. 8d): thereby, the STC decreased the *GWP* from almost 157,500 t CO_2eq to approximately 134,000 t CO_2eq by 15% in P2. Adding a BTES in P3 reduced the CHP share in the total heat production to only 10% and improved the *GWP* by 31% to approximately 93,000 t CO_2eq. Excluding the CHP altogether in P4 reduced the *GWP* by another 15% to approximately 79.000 t CO_2eq, which equals a reduction in the *GWP* of almost 50% compared to case P1.

By comparison, the *CED* behaves similarly to the *GWP* (Fig. 8b & e): with regard to P3 and P4, the CHP-dominated cases performed relatively better in BAU and worse in EVO. As a result, the reduction in the *CED* from P1 to P4 in EVO equates to approximately 53%, but only 21% in BAU.

The positive impact of enlarging the solar capacity and the storage capacity was slightly compromised by the relatively high *GWP*, which is associated with the production of the collectors and the BTES system (see Fig. 9). In combination with the generally decreasing total *GWP* from P1 through P4, this led to a notable increase in the significance of the production process in the total *GWP*, which is depicted in Fig. 8c & f.

3.1.2.2. Economic effects. In general, investment costs increased from P1 through P4 (Figs. 10a & 11), whereas operating costs and electricity sales decreased (Figs. 10b–d & 11). A comparison of the cases across all ECO scenarios illustrated the effects of the different boundary conditions (Fig. 11). Firstly, the increasing energy prices in EVO and EVO SUB raised the *LCOH* of all systems. Despite the growth in electricity sales (Fig. 10c and d), the fossil fuel-dominated cases P1 and P2 were affected most with an increase of 1.00 ct/kW h and 0.80 ct/kW h, respectively (Figs. 10d, 11). P3 and P4, on the other hand, were affected significantly less with a rise of 0.40 ct/kW h and 0.35 ct/kW h, respectively. Secondly, subsidies decreased the *LCOH*. They affected the sale of cogenerated electricity, as well as the investment costs for STC and BTES. Therefore, the resulting reduction depended on the capacities of the different system components (see Fig. 7 versus Fig. 11). However, despite the almost equal share of subsidizable heat production in all four cases, the *LCOH* reduction increased from approximately 0.82 ct/kW h in P1 to over 1.36 ct/kW h in P4, which implies that subsidies for STC and BTES investment outweighed subsidies for CHP electricity sales. P2 and P3 showed almost equal *LCOH* reductions of around 1.18 ct/kW h. In P3, most of the cogenerated electricity was used for self-supply. Accordingly, it was not subsidized.

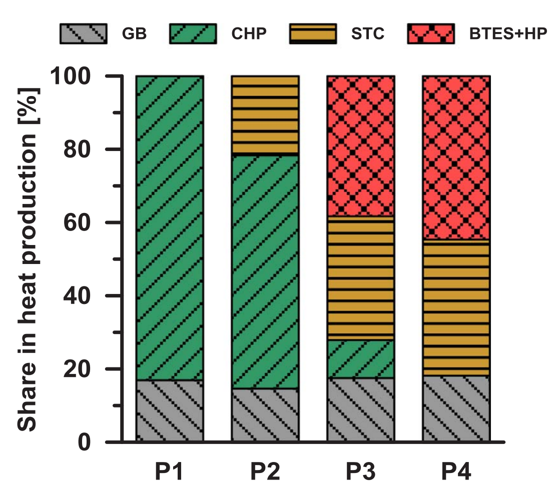

Fig. 7. Share in average annual heat production of the different system components.

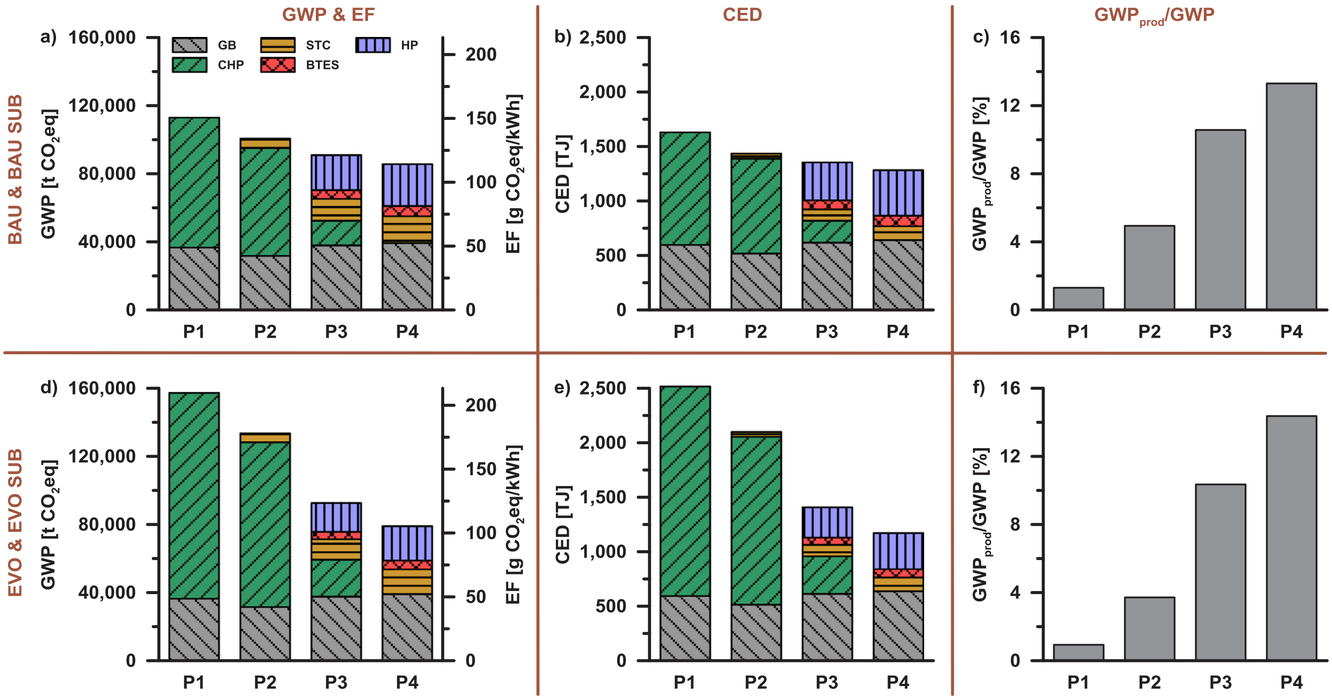

Fig. 8. Comparison of *GWP* (a + d), *CED* (b + e) and share of *GWP* associated with the production process in the overall *GWP* (c + f) for the four selected system designs and BAU and EVO, respectively.

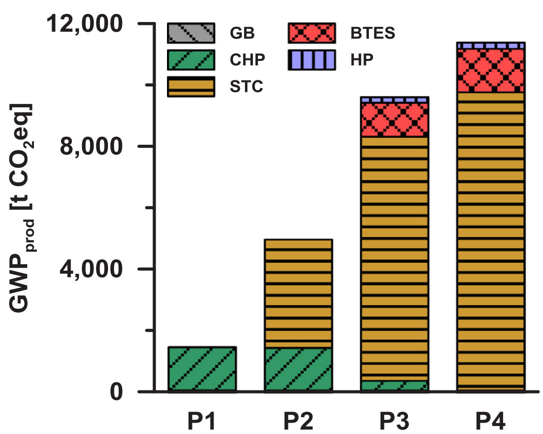

Fig. 9. *GWP* accounted to the production phase of each system component for the four scenarios under consideration.

3.2. Sensitivity analysis

For a sensitivity analysis of the *LCOH* in BAU, investment and energy costs were varied by up to 20% (Fig. 12). Differences between the four cases P1 to P4 indicate the sensitivity's dependency on the system composition. The results agree with the general correlation between the sensitivity and the operation-to-investment-cost ratio: the production of systems with a large STC and BTES share in the total heat supply was more expensive than CHP and GB-dominated systems. Thus, the *LCOH* can change by 0.92 ct/kW h and 1.08 ct/kW h in P3 and P4, respectively, if the investment costs vary by 20%. On the contrary, in P1 and P2 the *LCOH* only changed by 0.09 ct/kW h and 0.36 ct/kW h, respectively.

Inversely, a large share of operation costs in the *LCOH* resulted in a strong dependency on the energy prices. Despite the positive effect of electricity sales, the *LCOH* of CHP and GB-dominated systems was more sensitive to variations in energy costs. Assuming a coupled variation of the electricity price and the gas price by 20%, the *LCOH* can change by 0.73 ct/kW h and 0.59 ct/kW h, in P1 and P2 respectively, whereas P3 and P4 were only affected by changes of 0.29 ct/kW h and 0.36 ct/kW h, respectively.

4. Discussion

4.1. Limitations

The model-based study of complex systems, such as DH grids, requires many simplifications and assumptions, not only because of computational limitations, but mainly because too much detail in the model results in too much noise, which can obscure meaningful results. In order to investigate the impact of some of the adjusting parameters, other potentially influential variables have to be disregarded to suppress the effects of interdependencies.

Firstly, most simplifications result from a lack of adequate cost and LCA data for some of the system components. Particularly the LCA databases used for the environmental burdens were not designated for the dimensions of some of the system components. Thus, the study relies on values extrapolated from smaller units. For STC fields and HP, these extrapolations are linear and positive scaling effects were not taken into account. Moreover, there is no real field data available for BTES at all. They had to be compiled from data of the employed materials and estimates for fuel consumption. Despite these shortcomings, this is a conservative approach that does not overestimate the environmental benefits of the respective renewable technologies.

Secondly, the modelling of the DH system based on an energy balance is sensitive to errors. As a major simplification, the approach assumes that the thermal energy can always be transferred completely, not considering the fluid temperatures of the respective heat source and the grid. This means that the transfer of thermal energy is always in agreement with the first law of thermodynamics, but the model does not check for consistency with the second law. However, in this context the approach is expected to be viable: grid temperatures are relatively low as well as the return temperatures of the BTES. Consequently, the GB, the CHP and the STC are expected to generate fluid temperatures that are always high enough to ensure the feed-into the grid or the BTES. As the HP energy consumption is particularly sensitive to the

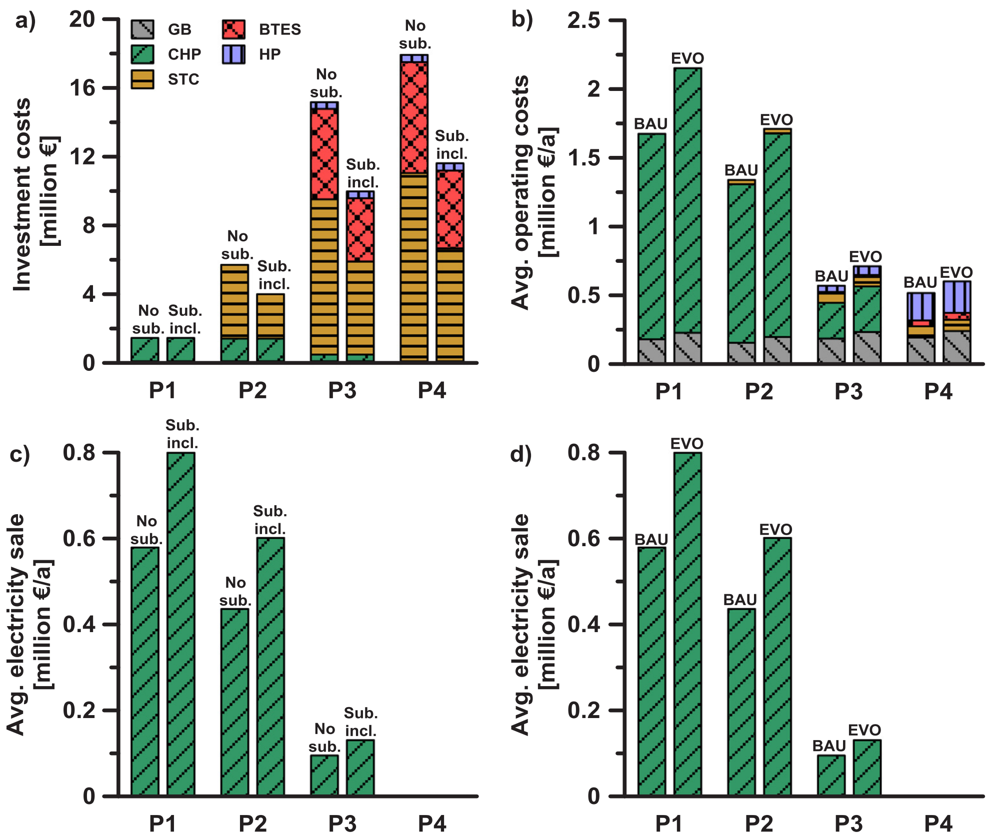

Fig. 10. Comparison of (a) investment costs, (b) average operating costs and (c + d) average electricity sale for the four selected system designs and different ECO scenarios.

BTES outlet, temperature cannot be disregarded for this particular subsystem. Realistic values for the BTES outlet temperature were determined by simulations to calculate a temperature-dependent coefficient of performance (see SI 3).

Lastly, the model disregards the distribution network of the DH grid. The production and operation of the grid itself can have a significant impact on the *LCOH* and the *GWP*. Nonetheless, as the heat demand remains unchanged, the impact is assumed to be the same for all systems and scenarios. A comprehensive model would have to consider the variabilities and possible saving potentials in the distribution network and in the heat demand at the end-consumer's level. However, this study focuses on the environmental and economic assessment of the heat-generating system components, especially of medium deep BTES. Disregarding the details of the DH grid and the end-consumers admittedly represents a simplification, but it eliminates noise irrelevant to the study from the results.

Aside from these simplifications, many assumptions are required to obtain meaningful results. Most assumptions are reflected in the different ECO scenarios. This includes subsidies, energy prices and the future energy mix in the electricity grid. Evidently, these assumptions are subject to uncertainty, which is not considered in this study. Therefore, the ECO scenarios are to be understood as the boundary points of a range of possible developments in the energy market. However, the development of the heat demand is not taken into account, but considered to remain constant at 25 GW h/a. As regulations in Germany require building reconstructions to include energy-saving measures [88], the energy demand per household has decreased over the past few decades. This trend will presumably continue, but has been identified as problematic for the efficiency and economic viability of existing DH grids [7,89]. Thus, more households will have to be connected to DH grids, if this technology is to play a role in the future. Therefore, the total heat demand will probably not decrease, and its development does not have to be considered in a study that focuses on the environmental and economic assessment of the heat-generating system components.

Another disputable assumption is the proposed CO_2-credit for co-generated electricity according to the emission factor of the grid mix. Replacement of grid electricity depends on regulations and the merit order, which means that, technically, the CO_2-credit cannot be attributed to power sources' emission factor with regard to their share in the grid mix. However, the replacement does not always comply with regulations, as a local overcapacity has to be balanced locally as well [90,91]. This makes predictions of the replaced electricity source and the associated CO_2-credit very difficult. For this reason, the CO_2-credit for replacing grid mix electricity is assumed as an average value, as it is usually handled in most other LCA studies too, and complies with the requirements for co-products set by DIN EN ISO 14040/44.

The EVO scenarios consider a development in the energy market, while possible regulatory changes are disregarded. A regulatory tool often criticized for not being effective is the EUA. In this study, the EUA was not considered, as it only applies to larger combustion plants and, were it applied, it would not have a large effect on the *LCOH* (Fig. 13). However, it is possible that the EU ETS will be extended to smaller plants and that the EUA price will be increased in the future in an attempt to meet the stipulations of the Paris Agreement [92]. Fig. 13 illustrates the effect on the *LCOH* of such an extension as the EU ETS and an increase of the EUA price. The differences between the BAU and EVO scenarios also show the interdependency of developments on the energy market: with a progressing grid electricity mix, renewable sources (STC and BTES) are less affected by the allowance price. As a consequence, both regulatory and market development aspects will need to be taken into account in future studies, if regulatory changes become more likely.

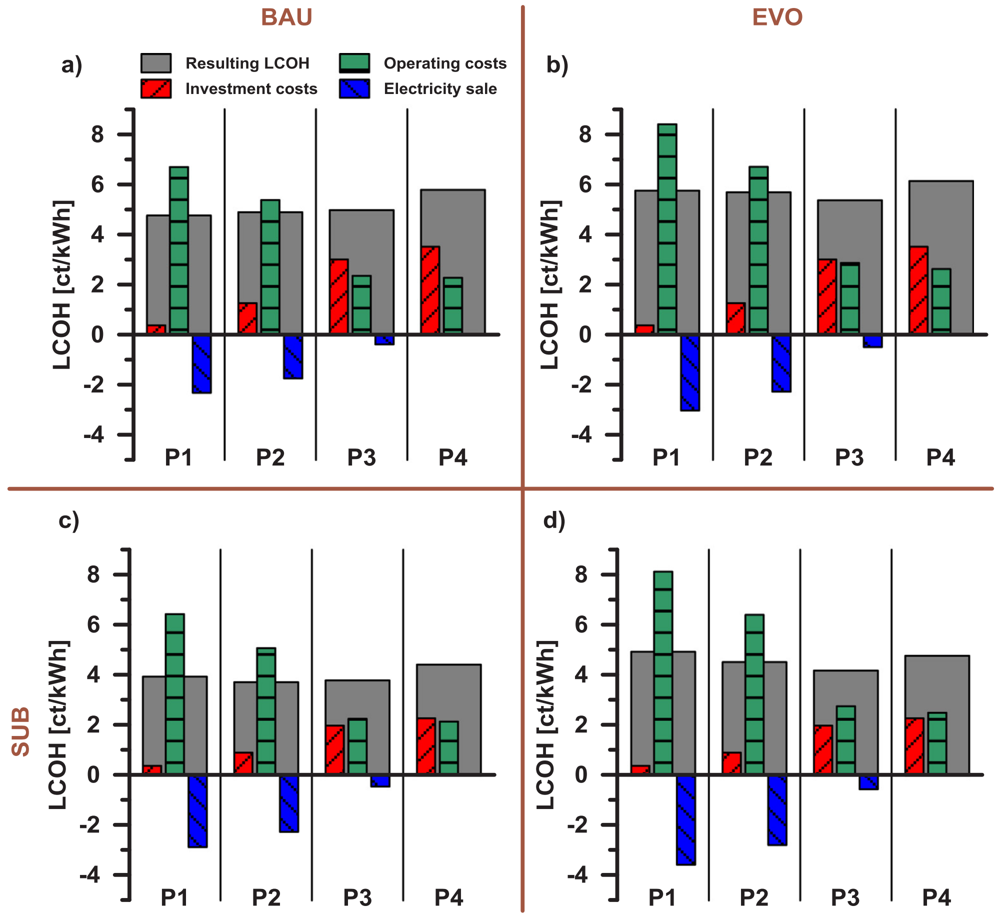

Fig. 11. Comparison of *LCOH* for the four selected layouts and the four ECO scenarios.

4.2. Discussion of results

The results provide different Pareto optimal system designs for the ECO scenarios under consideration with relatively similar *GWP* reductions. Only the subsidies cause an offset in the *LCOH* of the different Pareto optimal systems. Therefore, the optimal solutions appear equally good. However, the probabilities of the different assumptions about the existence of subsidies and the development of the energy market, which are pictured in the four ECO scenarios, are not equal. The development rate of renewable energies has not been steady in the past, and future trends are hard to predict. Yet, it is very likely that the share of renewable energy in the grid electricity mix will increase, and the emission factor of grid electricity can be expected to decrease. If the Pareto optimal solutions are weighted by the probability of the respective scenario, the STC + BTES solution with a small CHP unit for self-supplied electricity becomes the most favorable.

The combination of CHP + BTES is not favorable in any ECO scenario. CHP operation is considered to follow the heat load. Therefore, CHPs are dimensioned according to the base load of heat to avoid overcapacities. Thus, electricity sales are limited as they correspond to the heat provision. BTES allows for CHP operation to be decoupled from the heat demand as thermal energy can be stored for later use, even if the heat demand is low. As a result, CHP operation can follow the electricity demand instead and thereby realize higher prices for electricity sales. Then, the increased revenue could compensate the high investment costs for BTES and decrease the *LCOH*. The CHP operation following the electricity demand could not be investigated in this study, as it would require the consideration of a fluctuating electricity market but it can potentially make a CHP + BTES system as competitive as a CHP + STC + BTES system.

4.3. Comparison with other seasonal TES technologies

Storage capacities of efficient medium deep BTES designs for the assumed DH system lay in the range of 10 GW h/a. This corresponds to an equivalent water volume of approximately 140,000 m^3 (assuming a ΔT of 60 °C). Specific investment costs for such a BTES were approximately 38 €/(m^3 water eq.). Compared to this, specific investment costs for water storage tanks are rather high [21] (> 100 €/(m^3 water eq.), cf. [13,93]). Water pit storage systems are an affordable alternative (< 30 €/(m^3 water eq.), cf. [93]). However, such systems consist of a large excavation with an elevated rampart around it. The ground has to be stable enough to transfer the additional load from the water volume. Furthermore, pit systems constitute a significant interference in the landscape, which might cause discrepancies in the population. Gravel-water pits have a much lower landscape impact but require up to double the storage volume [21]. ATES systems can exploit sufficient storage volumes for reasonable prices and have a low landscape impact, but they rely on very specific hydrogeological site conditions. Firstly, hydraulic conductivities need to be high enough while groundwater flow has to be low and secondly, the mineral content of the utilized groundwater has to be limited. Although, BTES systems are restricted to geological formations, where groundwater flow is limited as well, the general geological requirements are much lower than that of ATES systems. Moreover, BTES systems are almost invisible and entail therefore almost no landscape impact. A further advantage of BTES systems is its very simple expandability by additional BHEs. Advantages of medium deep BTES systems over shallow ones are already elaborated in the introduction.

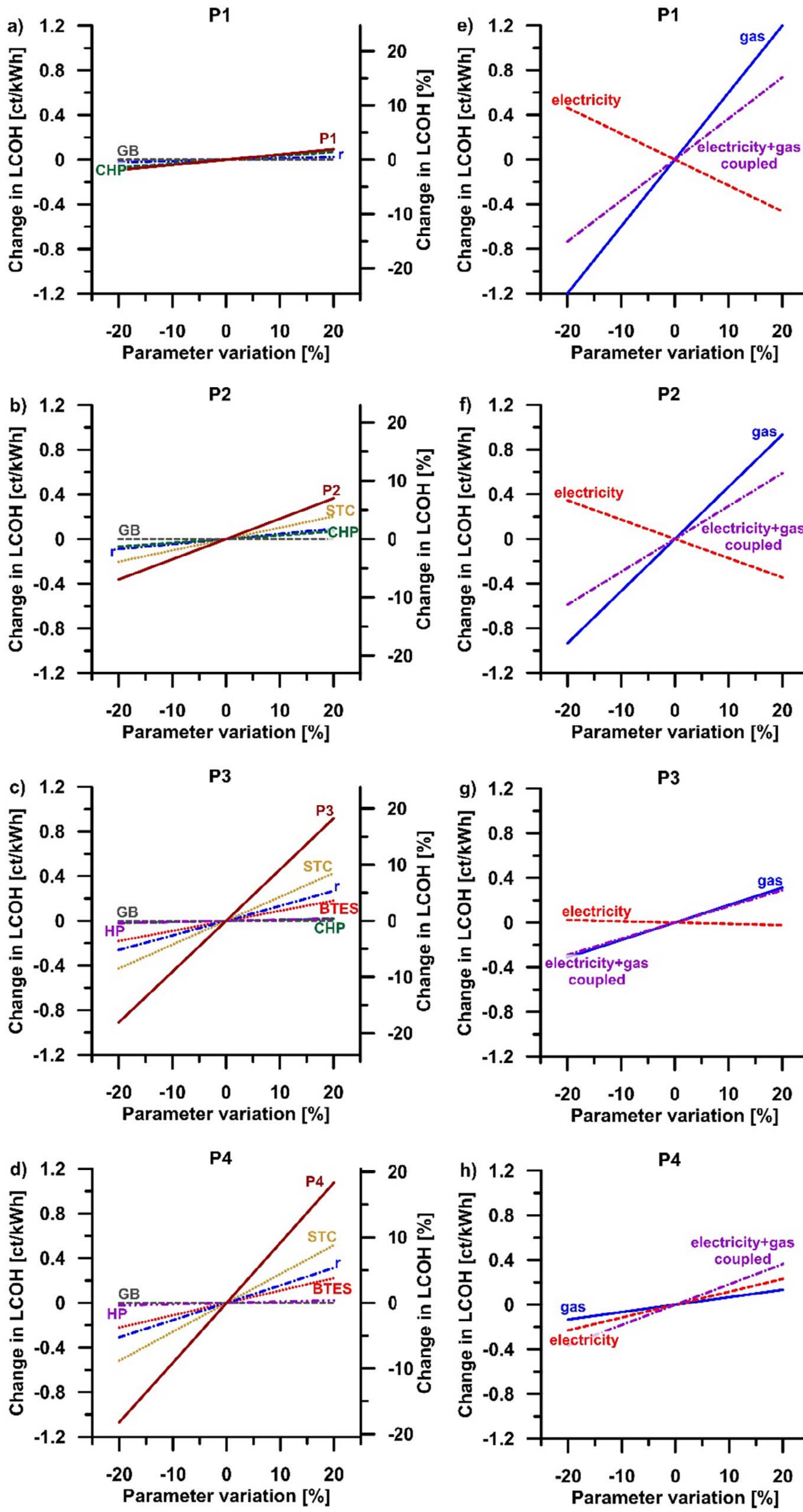

Fig. 12. Influence of investment costs (a–d) and the energy costs (e–h) on the *LCOH* for the four cases P1 to P4, considering the BAU scenario.

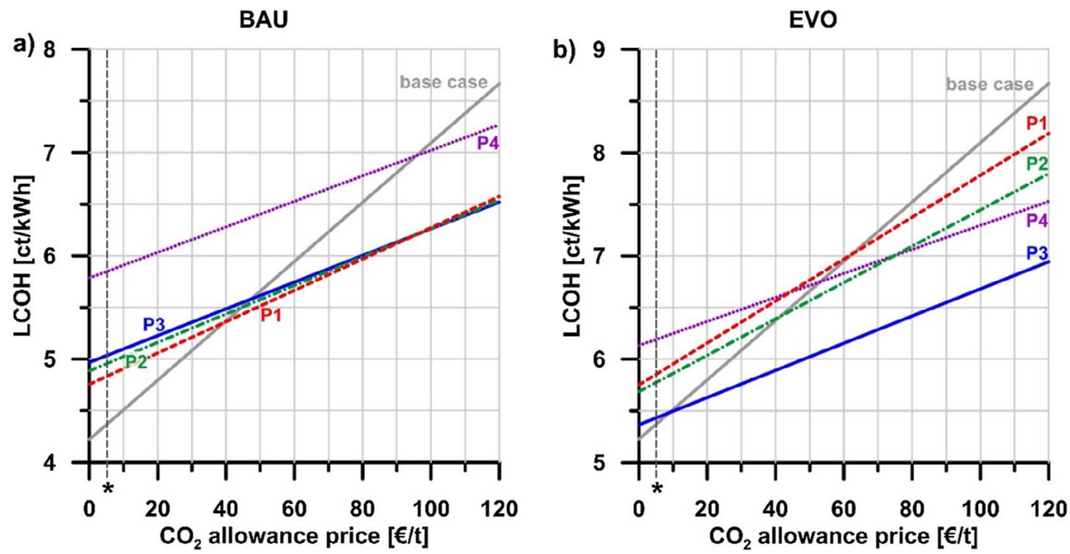

Fig. 13. Effect of implementing a CO_2 emissions allowance costs on *LCOH* for different scenarios. The dashed vertical lines (*) mark the current price level of EUAs at approximately 5 €/t.

5. Conclusions

Medium deep BTES is an advancement of conventional BTES technology, which is more independent from geological site conditions and has a much lower impact on landscape than competing technologies for large-scale seasonal heat storage. Consequently, its market introduction could result in a wider applicability of seasonal storage in DH systems but is opposed by high investment costs and uncertain environmental benefits.

Based on a life cycle approach, this study analyzes the economic and environmental effects of integrating medium deep BTES systems into a hypothetical low temperature DH grid under varying shares of STC-, CHP- and GB-capacity and under different ECO scenarios. Even though the ECO scenarios under consideration are based on German boundary conditions, the general conclusions concerning favorable conditions for BTES integration are transferable to other countries as well. The results are depicted as Pareto fronts, which illustrate the trade-off between cost efficiency and the reduction of *GWP*. Our approach allows for the identification of specific system designs that combine a large reduction in the *GWP* with reasonable *LCOH*. The basic results concerning the integration of medium deep BTES in district heating systems can be concluded as follows:

- The results are very sensitive to changes in the economic and environmental boundary conditions.
- The most promising system designs combine a large STC field and a large medium deep BTES system with a small CHP, which supplies the HP and circulating pumps with cogenerated electricity.
- Under the current market conditions, disregarding existing subsidies (BAU), this CHP + STC + BTES combination can significantly reduce the *GWP* by 54%, while increasing the *LCOH* by 13%, compared to the most economic system (i.e. GB-only). Nevertheless, it has to compete with highly efficient CHP-based technology combinations, which can achieve similar results.
- Assuming a very likely future rise in energy prices and a decrease in the electricity mix emission factor (EVO), CHP-based combinations are less attractive. The most favorable compromise solution without seasonal storage can achieve a *GWP* reduction of 29% by an increase in *LCOH* of 12%, compared to the most economic combination (i.e. GB + small STC). In contrast, the CHP + STC + BTES combination reduces the *GWP* by 33% or 50%, when accepting a rise in the *LCOH* by only 1.2% or 5.5%, respectively.
- Including German state subsidies in EVO SUB, CHP + STC + BTES depicts the most economic system combination. However, in the current market situation (BAU SUB) the subsidies offer an advantage to CHP-based systems. This leads to a crowding out of storage capacities.
- Less than 15% of the *GWP* of the CHP + STC + BTES combination can be attributed to the production phase. However, investment costs for STC, BTES and HP make up approximately 45% to 60% of the *LCOH*, constituting a major potential for savings.

All in all, our study highlights that medium deep BTES systems in combination with a large STC field and a small CHP can be a cost-effective alternative to large CHPs for mitigating GHG emissions in district heating systems. Our assessment tool can easily be adapted to other economic/environmental scenarios as well as to specific DH systems. Furthermore, the tool could be expanded by further heating or storage technologies. Thus, we provide an instrument, which could be used by system engineers or policy makers to assess the economic and environmental effects of different system designs or regulatory measures. Furthermore, the tool could be applied by DH operators to plan the integration of a BTES into an existing system, to gauge the current performance of their heating system, or assess the consequences of, for example, changes in energy prices or the electricity mix.

The construction of a pilot storage system should be the next step to assess the general practicability of the concept of medium deep BTES. Moreover, it could gather more precise data about the economics and environmental burden of the drilling process. Finally, a pilot storage system would serve as the first operational experience of such a system.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2018.02.011.

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