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System-driven design and integration of low-carbon domestic heating technologies

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ABSTRACT

This research explores various combinations of electric heat pumps (EHPs), hydrogen boilers (HBs), electric boilers (EBs), hydrogen absorption heat pumps (AHPs) and thermal energy storage (TES) to assess their potential for delivering cost-efficient low-carbon heat supply. The proposed technology-to-systems approach is based on comprehensive thermodynamic and component-costing models of various heating technologies, which are integrated into a whole-energy system optimisation model to determine cost-effective configurations of heating systems that minimise the overall cost for both the system and the end-user. Case studies presented in the study focus on two archetypal systems: (i) the North system, which is characterised by colder climate conditions and abundant wind resource; and (ii) the South system, which is characterised by a milder climate and higher solar energy potential. The results indicate a preference for a portfolio of low-carbon heating technologies including EHPs, EBs and HBs, coupled with a sizable amount of TES, while AHPs are not chosen, since, for the investigated conditions, their efficiency does not outweigh the high investment cost. Capacities of heat technologies are found to vary significantly depending on system properties such as the volume and diversity of heat demand and the availability profiles of renewable generation. The bulk of heat (83–97%) is delivered through EHPs, while the remainder is supplied by a mix of EBs and HBs. The results also suggest a strong impact of heat demand diversity on the cost-efficient mix of heating technologies, with higher diversity penalizing EHP relatively more than other, less capital-intensive heating options.

1. Introduction

The achievement of net-zero carbon emissions targets by 2050 represents a key commitment for many countries and organizations around the world [1,2]. The residential energy sector accounts for more than one-third of the global carbon emissions, and half of these emissions are associated with the demand for space heating and hot water [3]. A net-zero carbon heating provision requires the adoption of clean and emission-free technologies or a full offset of the emissions that may occur when using fossil fuel resources [4].

Natural gas boilers currently dominate the heat supply in the UK's residential sector, while the most implemented alternative options include electric heat pumps (HPs) [5], solar thermal heating or biomass (sometimes coupled with district heating [6,7]). Other options, such as hydrogen boilers (HBs) or hydrogen absorption heat pumps (AHPs) [8,9] appear promising but strongly rely on the hydrogen infrastructure and on the possibility to generate green hydrogen from renewables or low-carbon blue hydrogen from gas reforming with carbon capture, utilisation and storage (CCUS).

Electric vapour-compression HPs are a mature technology [10] with a higher energy efficiency and longer lifetime than gas boilers, but also a higher investment cost. The key performance indicator of electric HPs (EHPs), the coefficient of performance (COP), is greatly affected by the outdoor environmental conditions, which opens up opportunities for integration with thermal energy storage (TES) assets to increase the flexibility of energy systems [11]. A high deployment of EHPs will lead to significant additional electricity production requirements. For example, Quiggin and Buswell [12] showed that heating electrification could lead to an increase in peak electricity demand by up to 55 GW_{el} in

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Nomenclature

Abbreviations

AHP	Absorption heat pump
BECCS	Bioenergy with carbon capture and storage
COP	Coefficient of performance
DHN	District heat network
DSR	Demand-side response
EB	Electric boiler
EHP	Electric heat pump
EV	Electric vehicle
HB	Hydrogen boiler
HP	Heat pump
LCOE	Levelised cost of electricity
LCOH	Levelised cost of heat
LDC	Load duration curve
NET	Negative emission technology
PV	Photovoltaics
RES	Renewable energy sources
TES	Thermal energy storage

Subscripts/superscripts

abs	Absorber
genr	Generator (for AHPs)
AHP	Absorption heat pump
i	Hydrogen imports source index
bs	Battery storage
H2	Hydrogen supply system
ch	Storage charging
gas	Natural gas
comp	Compressor
HB	Hydrogen boiler
cond	Condenser
heat	Heat supply system
CO_2	Carbon dioxide emissions
hs	Hydrogen storage
dch	Storage discharging
k	Demand segment index
e	Electrolyser technology index
max	Maximum output
EB	Electric boiler
min	Minimum output
EHP	Electric heat pump
new	New capacity
el	Electricity
pump	Pump
el −	Demand shifted away from given hour
r	Methane reformer technology index
el +	Demand shifted towards a given hour
ref	Methane reforming
elH2	Electrolysis
RES	Renewable energy sources
ex	Existing capacity
s	Battery storage technology index
ext	External (demand)
t	Time interval index
fuel	Fuel
TES	thermal energy storage
g	Generation technology index
u	Hydrogen storage technology index

Symbols

α	No-load heat rate (MWh_{th}/hr)
β	Incremental heat rate (MW_{th}/MW_{el})
γ	Share of demand that can be shifted
δ	Volume of demand shifted (MW_{el})
Δ	Length of unit time interval (hr)
ϵ	Carbon emissions per unit of fuel (tCO_2/MWh)
η	Conversion efficiency
μ	Newly added capacity (MW)
ξ	Hydrogen production or consumption variable (MW_{H2})
Ξ	Non-heat hydrogen demand (MW_{H2})
π	Annualised investment cost per unit of capacity (£/MW/yr)
τ	Storage duration (hr)
φ	Total system cost component (£)
Φ	Annual emission limit (tCO_2/yr)
ψ	Efficiency of demand shifting
Ω	Maximum annual utilisation factor
a	Normalised availability factor for RES
A	Variable operation cost coefficient (non-fuel) (£/MWh)
cGenerator operation cost (£)d	Generator operation cost (£)d Electricity demand after DSR (MW_{el})
D	Electricity demand before DSR (MW_{el})
E	Number of electrolyser technologies
F	Cost of fuel (£/MWh)
G	Number of power generation technologies
h	Heat input/output of TES (MW_{th})
H	Number of H_2 storage technologies
HG	Set of H_2-fuelled electricity generation technologies
I	Number of hydrogen imports sources
J	Coincidence factor of heat demand
K	Number of electricity demand segments
L	Specific consumption per unit of H_2 output (MW/MW_{H2})
M	Maximum capacity (MW)
n	Number of generator units in synchronised operation
p	Power generation or consumption variable (MW_{el})
$\dot{Q}$	Heat output of end-use technology (MW_{th})
q	Energy content of energy storage (MWh)
R	Number of methane reforming technologies
RG	Set of renewable electricity generation technologies
S	Number of battery storage technologies
T	Number of time intervals in a year
T_{day}	Set of time intervals belonging to the same day
TG	Set of thermal electricity generation technologies
U	Number of hydrogen storage technologies
w	Output curtailment (MW_{el})
X	Heat demand (MW_{th})
z	Total system cost (£)

the UK, while Hoseinpoori et al. [13] demonstrated that peak electricity demand could increase by 170% by 2050. The development and integration of efficient and low-cost EHPs can therefore be key to decarbonise heat in countries with ambitious climate goals [14].

The "Net Zero" report from the UK Climate Change Committee (CCC) highlights heat electrification as a crucial step to decarbonisation [4]. However, this requires renewable or other low-carbon electricity to supply a continuous increase of electricity demand, which could pose issues for the security of supply and require grid reinforcement [15]. For these reasons, it is broadly recognised that the decarbonisation of heat via electrification will require the adoption of a portfolio of flexibility measures to reduce daily peak demands [16], including energy efficiency, demand-side response (DSR) [17] and change of end-user consumption habits [18], as well as the utilisation of various electrical [19] or thermal [20,21] energy storage technologies. Energy storage, which can be installed either at a domestic or an energy system level, can act as a buffer between heat demand and heat supply, potentially leading to substantial cost savings and reduced electricity generation requirements [22].

It has been shown that a cost-effective approach to decarbonise both heat and electricity supply requires coordination between heating and electricity systems to capture benefits from unlocking cross-vector flexibility and support the integration of low-carbon generation technologies [23]. Coordinated design of heat and electricity supply systems generally results in a lower low-carbon transition cost compared to a "silo" approach that addresses the two supply systems separately. Furthermore, optimally operating integrated heat and electricity systems can significantly improve cost competitiveness, as well as increase the resilience of the energy networks [24].

Cost-efficient decarbonisation of energy supply through integrating high penetrations of variable renewables such as wind or solar photovoltaics (PV) will require a wide variety of flexibility options to provide grid support, balancing, and security of supply [25]. These technologies include various forms of energy storage, DSR, expansion of interconnection capacity and deploying more flexible generation technologies, but also the options providing cross-vector flexibility or sector coupling, such as hydrogen production and conversion technologies [26,27].

Hydrogen has been shown to represent a promising option for integration within a wider energy system, providing opportunities for flexible interactions between electricity, heat and transport sectors in the UK [8,28]. Hydrogen could efficiently complement heat electrification in an integrated low-carbon energy system, as shown in Ref. [29], by replacing natural gas in domestic boilers. Hydrogen can be stored and transported, and there are different options to pursue a sustainable transition from existing natural gas to hydrogen-based infrastructures, as proposed in Ref. [8]. Producing hydrogen from renewable sources through electrolysis is currently costly [30] and several studies concluded that a 100% electric heating scenario including large-scale energy storage is a more cost-effective option [9,31]. In the work of Sunny et al. [8], it is shown that the most cost-effective hydrogen-based heat supply would involve deploying auto-thermal reforming (ATR) with CCUS and negative emission technologies (NETs). However, hydrogen also has some less desirable characteristics (e.g., safety concerns due to leakage [32] and flammability [33]), and therefore advanced engineering approaches will be required to ensure that the deployment of hydrogen technologies is viable and secure [32].

Another option to decarbonise heating are AHPs, which use thermal energy instead of electricity to extract heat from a low-temperature heat source (e.g., ambient air) and transfer it into a high-temperature sink. Absorption systems are gaining increased attention for heating applications, despite being mainly adopted for refrigeration [34]. Scoccia et al. [35] used experimental data to show that in countries where electricity prices are much higher than gas prices, gas-driven AHPs can economically outperform EHPs. Lu et al. [36] conducted a thermo-economic analysis of a gas-fired AHPs for high-temperature hot water application, reporting average payback period in south China of 3 years. Garrabrant et al. [37] reported a COP for AHPs in the range of 1.44–1.63, while Wu et al. [38] predicted values between 1.43 and 1.55. Instead of being driven by heat generated by a gas boiler, an AHP could be driven by heat from a hydrogen boiler [39].

Comprehensive methods to assess the whole-system competitiveness of electricity- and hydrogen-driven heating technologies are limited in literature. Hobley [40] explored different visions towards heat decarbonisation by 2050, concluding that gas will continue to play a key role in the UK energy mix. The study only included a simplified representation of technologies without including the costs of domestic hydrogen boilers or any absorption heat pump options. Furthermore, Chaudry et al. [41] assessed the implications of heat decarbonisation in Britain, estimating that hydrogen would be overall more costly than an electrification-only scenario. In that work, detailed modelling of technologies was not the focus, and therefore sensitivities around key heating technology costs and performance parameters were not conducted. According to the review of Scamman et al. [42], it is vital to improve the characterisation of technologies in current energy system models to accurately capture economies of scale. It is also crucial to include any emerging technologies in the mix of available options.

A techno-economic and whole-system analysis of different zero-carbon heating options has been proposed in the work of Olympios et al. [9], in which thermodynamic and component-costing models of different heating options were developed. It was shown that the relative competitiveness of different heating technologies greatly depends on the cost of electricity and hydrogen, which in turn depends on how hydrogen is produced and stored [43]. In all scenarios studied in Ref. [9], heating decarbonisation was assumed to take place exclusively through one heating technology, which was useful to understand the full range of implications of different technology choices. However, it was acknowledged that within a country, there can be significant variations in infrastructure costs, weather conditions, housing types and consumption patterns in different locations, concluding that it is not likely that a single solution would be sufficient [44].

This research aims to scale up the assessment of residential low-carbon heating technologies from the homeowner's perspective to the system-level perspective, addressing the added value that these technologies could offer in terms of enhanced flexibility of energy systems, and consequent potential reduction of energy supply costs. For this purpose, this work aims to integrate techno-economic models of a vapour-compression EHP, an AHP, a HB and an electric boiler (EB) within the Whole-electricity System Investment Model (WeSIM), a model of the whole UK energy system [45], which has recently been used to provide evidence to the government on heating decarbonisation [46]. WeSIM is here used to identify future heating technology mix in the UK that minimises total system cost that consist of investment and operation cost at both supply and demand side. Designing cost-efficient zero-carbon heating systems is well aligned with many global energy and climate change-related goals, such as the United Nations' Sustainable Development Goals, in particular Goal 7 (Affordable and Clean Energy) and Goal 11 (Sustainable Cities and Communities).

The novelty of the work lies in the fact that the sizing (i.e., investment) decisions and operation of different heating technologies are simultaneously optimised as part of the overall system cost optimisation, identifying the best combinations of these options for different geographies and scenarios. This approach to system-led optimisation of portfolios of heating technologies has not been properly addressed in the literature thus far.

The remainder of the study is organised as follows. Section 2 provides a description of the whole energy system model used in the study, also setting out key assumptions used in the modelling and describing the thermodynamic and component-costing models of the heating technologies under investigation. In Section 3, the results of the portfolio optimisation for low-carbon heating operations are presented, while the concluding remarks are provided in Section 4.

2. Method

This section presents the formulation of the energy system model used for identifying cost-efficient portfolios of low-carbon heating technologies, followed by the description of the techno-economic models of heating technologies used in the energy system model, and the summary of key assumptions used in the analysis.

2.1. Energy system model with decarbonised heating

The model described here represents a modified version of the WeSIM model [45]. This version integrates the cost and technical features of hydrogen production, storage and imports, as well as the features of end-use low-carbon heating technologies in order to minimise the overall cost of delivering heat and electricity to end-consumers. Investments in end-use heating technologies are optimised in the model concurrently with investments in electricity and hydrogen supply resources. This means that the temporal variations in the cost of producing electricity and hydrogen are endogenous to the model and a function of its investment decisions, and the model does not require specifying any exogenous sets of energy prices.

2.1.1. Objective function

The objective function minimised by the model represents the total system cost, which contains terms associated with: a) investment in electricity generation and storage and the associated operation cost, b) investment in hydrogen production and storage with associated operation cost including, if relevant, hydrogen import cost, and c) investment cost in end-use low-carbon heating technologies:

$$\min z = \varphi_{\mathrm{el}} + \varphi_{\mathrm{H2}} + \varphi_{\mathrm{heat}} \tag{1}$$

The electricity sector cost includes investment cost of generation assets and battery energy storage systems (BESS) as well as generators' operating cost:

$$\varphi_{\mathrm{el}} = \sum_{g=1}^{G} \pi_g^{\mathrm{gen}} \mu_g^{\mathrm{gen}} + \sum_{s=1}^{S} \pi_s^{\mathrm{bs}} \mu_s^{\mathrm{bs}} + \sum_{t=1}^{T} \sum_{g=1}^{G} c_{g,t}^{\mathrm{gen}} \tag{2}$$

The hydrogen sector cost consists of investment and operation costs of electrolysers, reformers and hydrogen storage, plus the cost of hydrogen imports:

$$\begin{aligned}\varphi_{\mathrm{H2}} = &\sum_{e=1}^{E} \pi_e^{\mathrm{elH2}} \mu_e^{\mathrm{elH2}} + \sum_{r=1}^{R} \pi_r^{\mathrm{ref}} \mu_r^{\mathrm{ref}} + \sum_{u=1}^{U} \pi_u^{\mathrm{hs}} \mu_u^{\mathrm{hs}} \\ &+ \sum_{t=1}^{T} \left[\sum_{i=1}^{I} F_i^{\mathrm{imp}} \xi_{i,t}^{\mathrm{imp}} + \sum_{e=1}^{E} A_e^{\mathrm{elH2}} \xi_{e,t}^{\mathrm{elH2}} + \sum_{r=1}^{R} \left(A_r^{\mathrm{ref}} + F_{\mathrm{gas}} L_r^{\mathrm{gas}} \right) \xi_{r,t}^{\mathrm{ref}} \right]\end{aligned} \tag{3}$$

The investment cost of end-use heat technologies includes the investment costs of: EHP, EB, HB, AHP and TES assets:

$$\varphi_{\mathrm{heat}} = \pi^{\mathrm{EHP}} \mu^{\mathrm{EHP}} + \pi^{\mathrm{EB}} \mu^{\mathrm{EB}} + \pi^{\mathrm{HB}} \mu^{\mathrm{HB}} + \pi^{\mathrm{AHP}} \mu^{\mathrm{AHP}} + \pi^{\mathrm{TES}} \mu^{\mathrm{TES}} \tag{4}$$

2.1.2. Electricity and hydrogen balance constraints

The electricity balance constraint is formulated for each time interval t stipulating that total electricity supply needs to match total demand across various categories, which include electrified heating but also other non-heat segments:

$$\begin{aligned}&\sum_{g=1}^{G} p_{g,t}^{\mathrm{gen}} + \sum_{s=1}^{S} \left(p_{\mathrm{dch},s,t}^{\mathrm{bs}} - p_{\mathrm{ch},s,t}^{\mathrm{bs}} \right) = \sum_{k=1}^{K} d_{k,t}^{\mathrm{el}} + p_t^{\mathrm{EHP}} + p_t^{\mathrm{EB}} + \sum_{r=1}^{R} L_r^{\mathrm{el}} \xi_{r,t}^{\mathrm{ref}} \\ &+ \sum_{e=1}^{E} L_e^{\mathrm{el}} \xi_{e,t}^{\mathrm{elH2}}\end{aligned} \tag{5}$$

Non-heat demand segments relate to baseline, appliance and EV demand, and also include the effect of DSR for each segment k:

$$d_{k,t}^{\mathrm{el}} = D_{k,t}^{\mathrm{el}} + \delta_{k,t}^{\mathrm{el+}} + \delta_{k,t}^{\mathrm{el-}} \tag{6}$$

$$\delta_{k,t}^{\mathrm{el-}} \le \gamma_k^{\mathrm{el}} D_{k,t}^{\mathrm{el}} \tag{7}$$

$$\sum_{t \in T_{\mathrm{day}}} \delta_{k,t}^{\mathrm{el-}} \le \psi_k^{\mathrm{el}} \sum_{t \in T_{\mathrm{day}}} \delta_{k,t}^{\mathrm{el+}} \tag{8}$$

Hydrogen balance requires that hydrogen supply from electrolysers, reformers and imports matches total hydrogen demand at every time interval t, including non-heat demand for hydrogen, demand from HBs and AHPs, consumption of hydrogen power generators and net hydrogen storage operation:

$$\begin{aligned}&\sum_{r=1}^{R} \xi_{r,t}^{\mathrm{ref}} + \sum_{e=1}^{E} \xi_{e,t}^{\mathrm{elH2}} + \sum_{i=1}^{I} \xi_{i,t}^{\mathrm{imp}} = \sum_{u=1}^{U} \left(\xi_{\mathrm{ch},u,t}^{\mathrm{hs}} - \xi_{\mathrm{dch},u,t}^{\mathrm{hs}} \right) + \xi_t^{\mathrm{HB}} + \xi_t^{\mathrm{AHP}} + \xi_t^{\mathrm{gen}} \\ &+ \Xi_t^{\mathrm{ext}}\end{aligned} \tag{9}$$

The volume of hydrogen used for power generation is linked to generator outputs and heat rates as follows:

$$\xi_t^{\mathrm{gen}} = \sum_{\substack{g=1 \\ g \in HG}}^{G} \left(\alpha_g^{\mathrm{gen}} n_{g,t}^{\mathrm{gen}} + \beta_g^{\mathrm{gen}} p_{g,t}^{\mathrm{gen}} \right) \tag{10}$$

2.1.3. Generator-level constraints for electricity generation

The maximum new capacity of generation technology g is specified as:

$$\mu_g^{\mathrm{gen}} \le M_g^{\mathrm{new}} \forall g \in TG \tag{11}$$

Thermal generators (TG) are modelled at unit level. The number of generation units in synchronised operation at time t is bound by the total number of units, which is the sum of existing and newly added units:

$$n_{g,t}^{\mathrm{gen}} P_g^{\mathrm{max}} \le \mu_g^{\mathrm{gen}} + M_g^{\mathrm{ex}} \forall t \forall g \in TG \tag{12}$$

The generator output level is limited from above and below as follows:

$$n_{g,t}^{\mathrm{gen}} P_g^{\mathrm{min}} \le p_{g,t}^{\mathrm{gen}} \le n_{g,t}^{\mathrm{gen}} P_g^{\mathrm{max}} \forall t \forall g \in TG \tag{13}$$

The operating cost for the generation technology g at time t is quantified as follows:

$$c_{g,t}^{\mathrm{gen}} = \left(\alpha_g^{\mathrm{gen}} n_{g,t}^{\mathrm{gen}} + \beta_g^{\mathrm{gen}} p_{g,t}^{\mathrm{gen}} \right) \cdot \Delta \cdot F_g^{\mathrm{gen}} \forall t \forall g \in TG \tag{14}$$

Maximum annual output limits for generators are formulated as follows:

$$\sum_{t=1}^{T} p_{g,t}^{\mathrm{gen}} \le \left(\mu_g^{\mathrm{gen}} + M_g^{\mathrm{ex}} \right) P_g^{\mathrm{max}} \Omega_g^{\mathrm{gen}} T \forall g \in TG \tag{15}$$

Other constraints associated with generator dynamic constraints (ramping, start-up, reserve, frequency response and inertia) are omitted here for brevity; details can be found in Ref. [45].

Constraints applying to variable renewable generation (RG) are formulated in a different manner. The maximum allowed new capacity is limited to the pre-specified level:

$$\mu_g^{\mathrm{gen}} \le M_g^{\mathrm{new}} \forall g \in RG \tag{16}$$

The relationship between variable RES generation output and curtailment is formulated as follows:

$$p_{g,t}^{\mathrm{gen}} + w_{g,t}^{\mathrm{gen}} = \left(\mu_g^{\mathrm{gen}} + M_g^{\mathrm{ex}} \right) a_{g,t}^{\mathrm{RES}} \forall t \forall g \in RG \tag{17}$$

2.1.4. Constraints for battery storage

The maximum new capacity limit for BESS:

$$\mu_s^{\mathrm{bs}} \le M_s^{\mathrm{new}} \forall s \tag{18}$$

Limits for BESS charging and discharging will depend on the capacity added by the model:

$$p_{\mathrm{dch},s,t}^{\mathrm{bs}}, p_{\mathrm{ch},s,t}^{\mathrm{bs}} \le \mu_s^{bs} \forall s \tag{19}$$

The BESS balance constraint and energy limit are implemented as follows:

$$q_{s,t}^{\mathrm{bs}} = q_{s,t-1}^{\mathrm{bs}} + \left(\eta_{\mathrm{ch},s}^{\mathrm{bs}} p_{\mathrm{ch},s,t}^{\mathrm{bs}} - \frac{1}{\eta_{\mathrm{dch},u}^{\mathrm{bs}}} p_{\mathrm{dch},s,t}^{\mathrm{bs}} \right) \cdot \Delta \tag{20}$$

$$q_{s,t}^{\text{bs}} \leq \mu_s^{\text{bs}} \tau_s^{\text{bs}} \tag{21}$$

2.1.5. Constraints for hydrogen production and storage

Constraints on new capacity for electrolysers, reformers and hydrogen storage are formulated as follows:

$$\mu_e^{\text{elH2}} \leq M_e^{\text{new}} \forall e, \mu_r^{\text{ref}} \leq M_r^{\text{new}} \forall r, \mu_u^{\text{hs}} \leq M_u^{\text{new}} \forall u \tag{22}$$

The hydrogen output of various technologies is limited as follows:

$$\xi_{e,t}^{\text{elH2}} \leq \mu_e^{\text{elH2}} \forall e, \xi_{r,t}^{\text{ref}} \leq \mu_r^{\text{ref}} \forall r, \xi_{i,t}^{\text{imp}} \leq M_i^{\text{imp}} \forall i \tag{23}$$

$$\xi_{\text{ch},u,t}^{\text{hs}}, \xi_{\text{dch},u,t}^{\text{hs}} \leq \mu_u^{\text{hs}} \forall u \tag{24}$$

Hydrogen storage balance constraint and energy limit are implemented in the following way:

$$q_{u,t}^{\text{hs}} = q_{u,t-1}^{\text{hs}} + \left(\eta_{\text{ch},u}^{\text{hs}} \xi_{\text{ch},u,t}^{\text{hs}} - \frac{1}{\eta_{\text{dch},u}^{\text{hs}}} \xi_{\text{dch},u,t}^{\text{hs}} \right) \cdot \Delta \tag{25}$$

$$q_{u,t}^{\text{hs}} \leq \mu_u^{\text{hs}} \tau_u^{\text{hs}} \tag{26}$$

2.1.6. Constraints on end-use heating technologies

General heat balance includes the output of all heat technologies, which needs to meet the heat demand at time t:

$$p_t^{\text{EHP}} \eta_t^{\text{EHP}} + p_t^{\text{EB}} + \xi_t^{\text{HB}} \eta^{\text{HB}} + \xi_t^{\text{AHP}} \eta_t^{\text{AHP}} + h_{\text{dch},t}^{\text{TES}} - h_{\text{ch},t}^{\text{TES}} = X_t \tag{27}$$

Upper bounds on heat technology outputs take into account the heat demand coincidence factor J (note that all heat technology capacities are expressed as heat output rates):

$$p_t^{\text{EHP}} \eta_t^{\text{EHP}} \leq J \mu^{\text{EHP}}, p_t^{\text{EB}} \leq J \mu^{\text{EB}} \tag{28}$$

$$\xi_t^{\text{HB}} \eta^{\text{HB}} \leq J \mu^{\text{HB}}, \xi_t^{\text{AHP}} \eta_t^{\text{AHP}} \leq J \mu^{\text{AHP}} \tag{29}$$

$$h_{\text{dch},t}^{\text{TES}}, h_{\text{ch},t}^{\text{TES}} \leq J \mu^{\text{TES}} \tag{30}$$

TES balance and energy limit constraints are implemented as follows:

$$q_t^{\text{TES}} = q_{t-1}^{\text{TES}} + \left(\eta_{\text{ch}}^{\text{TES}} h_{\text{ch},t}^{\text{TES}} - \frac{1}{\eta_{\text{dch}}^{\text{TES}}} h_{\text{dch},t}^{\text{TES}} \right) \cdot \Delta \tag{31}$$

$$q_t^{\text{TES}} \leq J \mu^{\text{TES}} \tau^{\text{TES}} \tag{32}$$

Note that the operating cost of low-carbon heating technologies is implicitly considered through electricity and hydrogen balance equations.

2.1.7. System-wide carbon constraint

Total carbon emissions in the energy system result from the operation of fossil-fuelled thermal generators and methane reformers used for hydrogen production. An annual system-wide carbon emission target is introduced as follows:

$$\Delta \sum_{t=1}^{T} \left(\sum_{\substack{g=1 \\ g \in TG}}^{G} \left(\alpha_g^{\text{gen}} n_{g,t}^{\text{gen}} + \beta_g^{\text{gen}} p_{g,t}^{\text{gen}} \right) \epsilon_g^{\text{gen}} + \sum_{r=1}^{R} L_r^{\text{gas}} \xi_{r,t}^{\text{ref}} \epsilon_r^{\text{ref}} \right) \leq \Phi_{CO_2} \tag{33}$$

System reliability constraints are also included in the model as in Ref. [45].

2.2. Techno-economic models of end-use heating technologies

To compare end-use heating technologies from a whole-energy system perspective, this section presents techno-economic models for EHPs, AHPs, EBs and HBs. These models are used to capture how the technology design and operating conditions affect the performance and cost of these options, which may affect the design of the energy system and cost-optimal heat decarbonisation pathways.

EHPs in small-scale applications involve four main components: a compressor, a condenser, an expansion valve and an evaporator. The HP process involves heat being extracted from a source (e.g., air, ground) and transferred to the working fluid (i.e., the refrigerant) in the evaporator. The working fluid, which leaves the evaporator in vapour form, is raised to a higher pressure and temperature by an electrically driven compressor. It is then condensed, rejecting heat to hot water for domestic use. Following the condenser, the working fluid passes through the expansion valve, where its temperature and pressure are reduced, and it then flows back to the evaporator.

Three of the four main components of an EHP are the same in an AHP, but instead of an electrically driven compressor, an absorption cycle is used to raise the temperature and pressure of the working fluid. The absorption system requires two fluids: a refrigerant and an absorbent. The refrigerant coming out of the evaporator is in this case absorbed by the absorbent to form a liquid solution, which is pumped to a higher pressure and temperature in a process that requires a negligible amount of electricity. The main source of energy in an AHP comes from a high-temperature source in the generator, which is needed to desorb the refrigerant from the liquid solution.

Validated spatially lumped thermodynamic models of an EHP and an AHP have been developed in previous work by the authors [9]. Both models assume that all components operate at steady-state conditions and that there are negligible losses in pipes and heat exchangers. Component-costing correlations are used to identify the costs of different HP components, which is further validated using manufacturer data for HPs available in the UK market. Although the data available on AHPs is limited, the absorption HP model was validated in Ref. [9] by comparing its performance against the relevant literature. The authors have also developed a thermodynamic model of a hydrogen boiler in Ref. [9], while the efficiency of an EB was assumed to be close to 100%, and therefore no specific thermodynamic model has been developed.

Operating conditions of HPs, such as the outdoor temperature, will impact their performance. The COP of an EHP represents the ratio of the heat output from the condenser and the compressor electricity input [9]:

$$COP_{\text{EHP}} = \frac{\dot{Q}_{\text{cond}}}{p_{\text{comp}}} \tag{34}$$

The COP of an AHP on the other hand represents the ratio of the sum of the heat output from the condenser and absorber and the sum of the pump electricity input (which is often neglected) and the heat input in the generator:

$$COP_{\text{AHP}} = \frac{\dot{Q}_{\text{abs}} + \dot{Q}_{\text{cond}}}{p_{\text{pump}} + \dot{Q}_{\text{genr}}} \tag{35}$$

The EB efficiency (η_{EB}) and HB efficiency (η_{HB}) represent the ratios of the heat output over the electricity input (p_{EB}) and fuel input ($\dot{Q}_{\text{fuel}}$), respectively:

$$\eta_{\text{EB}} = \frac{\dot{Q}_{\text{EB}}}{p_{\text{EB}}}, \eta_{\text{HB}} = \frac{\dot{Q}_{\text{HB}}}{\dot{Q}_{\text{fuel}}} \tag{36}$$

Using the thermodynamic and component-costing models of these end-use technologies, simple relationships are developed here that capture how the COP of EHPs and AHPs is affected by the outdoor temperature (Fig. 1a) and how the specific price of all options is affected by their nominal heat output (Fig. 1b). R32 is chosen as the working fluid for the electric HP, while, for the AHP, ammonia and water are chosen as the refrigerant and absorber, respectively [47]. The hot-water delivery temperature is assumed to be fixed at 55 °C, which is the minimum required for domestic hot water and space heating.

This paper is among a small number of studies that involves an effort to capture how technology cost and performance depend on technology

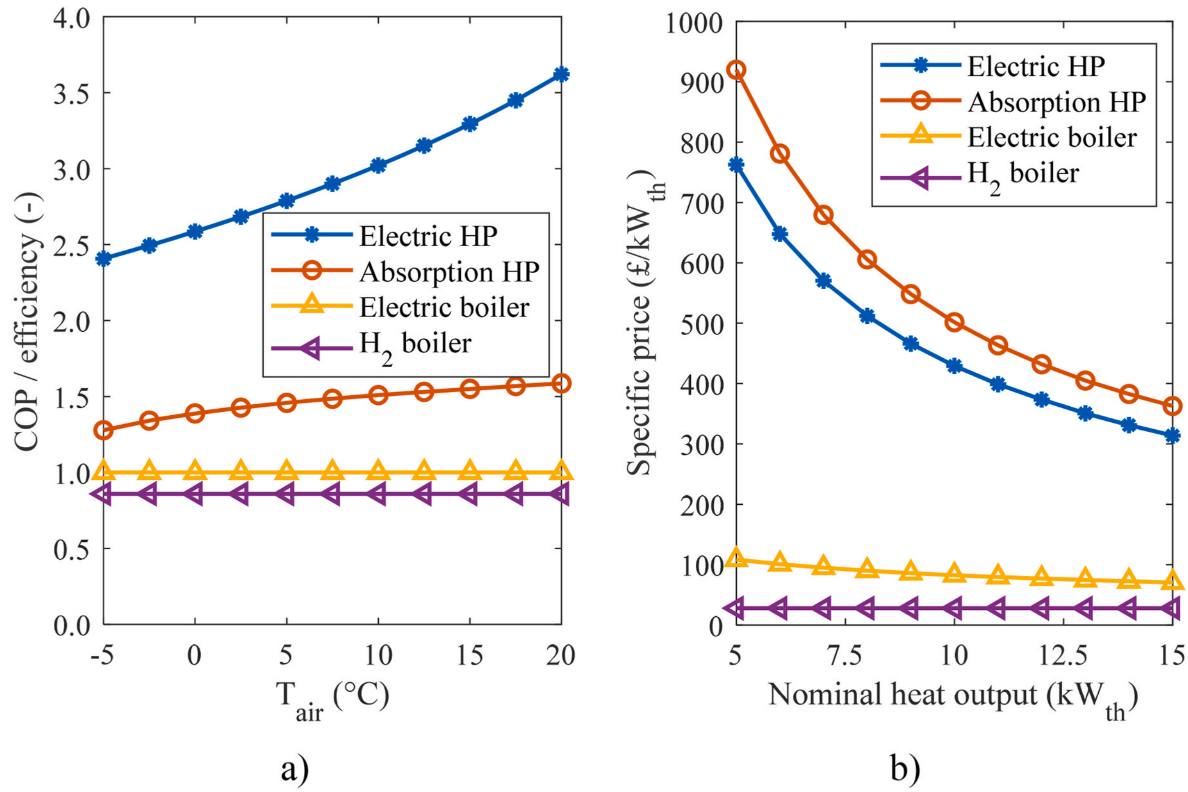

Fig. 1. Cost and performance of different end-use heating technologies: (a) COP or energy conversion efficiency as a function of air temperature (for a hot-water delivery temperature of 55 °C), and (b) specific price as a function of nominal heat output. Specific price excludes installation costs.

size and operating conditions, however, all technology data used in the study are still subject to uncertainties. Since technology prices are notably influenced by economic, demographic, and technological changes, making accurate estimates remains challenging. Technological learning from extended roll out of several technologies is likely to reduce both their investment and installation costs in the future, but each considered heating technology would be affected differently, as shown in the work of Renaldi et al. [48]. Based on this, the approach used in this work involves using as much of the commercially available data as possible. Hence, for any technologies that already exist, the input data is based on the information available from current manufacturer price lists.

Specific prices in Fig. 1b are calculated in GBP and include a value-added tax (VAT) of 20%. The prices of EHPs and AHPs are calculated using the developed component-costing models. For the EBs, a best-fit line based on power regression is found using the cost data for more than 25 commercially available units within the investigated heat output range (5–15 kW_{th}). Lastly, based on the recent commitment made by four of the most prominent boiler manufacturers [49], the price of HBs is expected to be soon become similar to natural gas boilers for domestic consumers, so the HB cost is obtained from the average price of over 50 commercially available natural gas boilers [50].

Note that natural gas boilers on the market are typically oversized, and the range of nominal heat output for which data was collected is 24–30 kW_{th}. No significant relationship was identified between the specific price and the size of a gas boiler in this range, and therefore the average specific price is plotted in Fig. 1b for comparison purposes. Installation costs, which are excluded from Fig. 1b, are assumed to be £2200 for HPs and £1400 for boilers [51]. It is important to note that the provided installation costs are only current estimates; these can vary significantly across different types of heat pumps, manufacturers, and configurations. Further analysis and uncertainty quantification for the cost and performance of all considered technologies and components can be found in Ref. [52].

2.3. System scenarios and assumptions

To study the impact of system characteristics on cost-efficient portfolios of low-carbon heat technologies, two generic geographic systems have been assumed: North and South. Both systems have been sized to broadly match the size of the UK electricity system with an annual demand of 400 TWh_{el}. These two archetypal systems can represent many countries or regions in Europe and beyond, and hence the results presented in this work apply more generally than just for a single national energy system.

The two systems differed in two main ways:

1. North system is characterised by colder climate conditions, which is reflected in a much higher residential heating demand (185 TWh_{th}) to be supplied by low-carbon sources than in the South system (36 TWh_{th}). Heat demand profile in the North was based on an annual temperature profile with an average temperature of 10.7 °C and 1884 heating degree days; in the South the average temperature was 18.3 °C with 554 heating degree days. Peak heat demand was also much higher in the North than in the South, as illustrated in the heat Load Duration Curves (LDCs) for the two systems in Fig. 2. At the same time the electricity demand for cooling is several times higher in the South (40 TWh_{el}) than in the North (6 TWh_{el}).
2. RES potential is assumed to differ between the two systems so that the available wind utilisation factors in the North were much higher than in the South (58% vs. 35%), while for solar PV generation the utilisation factor is assumed to be lower in North than in the South (11% vs. 24%). This resulted in the Levelised Cost of Electricity (LCOE) of wind and PV in the North of £43/MWh and £56/MWh, respectively, while in the South the same LCOEs were £39/MWh and £25/MWh.

In all studies, both systems are optimised to reach net zero carbon emissions, which could be achieved by investing in a range of zero-

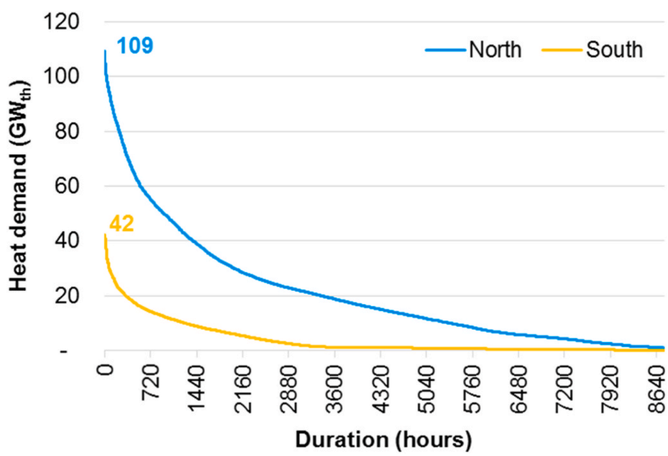

Fig. 2. Load duration curves (LDCs) for hourly heat demand in North and South systems.

carbon and positive-carbon technologies as well as carbon offsets in the form of electricity generators using Bioenergy with Carbon Capture and Storage (BECCS). Energy systems have been modelled in hourly resolution as single node systems, i.e., ignoring any transmission, interconnection or distribution networks.

The model was used to cost-optimise the supply of low-carbon heat to 15 million residential customers by investing in a portfolio of available technologies including EHPs, AHPs, EBs, HBs and TES. In addition to any hydrogen demand for residential heating (which was subject to optimisation in the model), it was also assumed there was a hydrogen demand of 97.5 TWh per year to meet the requirements in the industry and transport sectors.

The assumed costs of low-carbon heat options were based on the analysis presented in the previous section and on typical asset sizes, as follows (note that these figures include both the component costs from Fig. 1 and the relevant installation cost):

- EHP: £578/kW_{th}
- AHP: £638/kW_{th}
- EB: £139/kW_{th}
- HB: £98/kW_{th}
- TES: £75/kWh_{th}

In addition to initial investment, it was assumed that all assets also incur an annual maintenance cost of £35/kW_{th}/yr except for TES, where this cost was £20/kW_{th}/yr. It is important to emphasise that maintenance costs can vary significantly between different technologies. Accurately predicting current and future maintenance costs of various technologies is challenging, as they depend on various factors (component complexity, technological advancements, changes in maintenance strategies, specific operational requirements, regulatory frameworks, labour expertise etc.), introducing a layer of uncertainty. Nevertheless, in comparison with investment and operation costs, the significance of maintenance costs is relatively low [51].

Asset lifetime was assumed to be 20 years for EHPs and AHPs and 15 years for EBs, HBs and TES. A 5% interest rate has been assumed for all heating technologies to convert overnight cost into annualised values required by the model. The assumed duration of TES (the ratio between energy capacity and heat discharge rate) was 3 h.

The cost of gas available for power generation and H_2 production in reformers was assumed to be £21.8/MWh, although it is acknowledged this is far lower than gas prices seen during the recent spikes in energy prices in 2022. Hydrogen import was also assumed to be available at the relatively high price of £100/MWh. Note that, for simplicity reasons, district heat networks (DHNs) are not included in the scope of this analysis, although it is understood that they could make a significant contribution to the UK's future low-carbon heat sector [53].

In addition to the baseline system scenarios for the North and South systems, the quantitative analysis presented in this work also includes the following sensitivity studies:

- Impact of higher investment cost of BESS (50% above baseline).
- Sensitivities on heat demand coincidence factors: in addition to the default value of $J = 1$, the analysis also looked at values of 0.75, 0.5 and 0.25.
- Impact of restricting which low-carbon heat technologies are available for investment in the model: 1) EHP only, 2) EHP + TES, 3) EHP + EB, and 4) EHP + HB.

Diversity of energy demand is critically important for planning and studying energy supply and distribution infrastructure. It is based on the well-known fact that the timings of peak energy use for a larger group of customers will not coincide exactly, so that the aggregate peak demand of the group will be lower than the sum of individual customer peaks. This allows for network components to be sized to meet aggregate (diversified) peak demand rather than the total of individual customer peaks, which are extremely unlikely to occur at the same time. Diversity is typically quantified using the coincidence factor J, which is defined as the ratio between diversified and non-diversified peak per customer [54].

With respect to the restricted availability scenarios that do not include any TES (EHP only, EHP + EB and EHP + HB), it has to be noted that EHPs in domestic systems are generally not used to supply domestic hot water demand directly (unlike space heating). In a typical application the EHP charges a hot water cylinder, and DHW demand is met by drawing water from that cylinder. Since most households already have a hot water cylinder installed as part of the gas boiler-based central heating system, no additional costs are assumed in these scenarios.

3. Results

This section presents the results of system modelling aimed at establishing cost-efficient portfolios of low-carbon heating technologies for a variety of system conditions and scenarios. The case studies address the following aspects:

- Impact of system geography, reflected in the volumes of heating (and cooling) demand and in the availability of wind and solar PV resources
- Impact of higher cost of battery energy storage systems (BESS)
- Impact of diversity of heat demand, i.e., of the ratio between diversified (aggregate) and non-diversified (household-level) peak heat demand
- Impact of availability of various low-carbon heat technologies

Key quantitative modelling results include the capacity mix of low-carbon heating technologies and their annual volumes of supplied heat. The section also discusses the effect of various low-carbon heating scenarios on annual supply of electricity and hydrogen from the integrated energy system. Finally, the impact of various low-carbon heating scenarios on the total energy system cost and on the levelised cost of heat (LCOH) are presented.

3.1. Cost-efficient portfolios of end-use heat technologies for baseline scenarios

Cost-efficient portfolios of low-carbon heating options, optimised from the system perspective, are presented in Fig. 3 for North and South systems. Fig. 3a presents the breakdown of peak heat capacity in GW_{th} across different technologies.

Several key observations can be drawn from the results. Firstly, the AHP does not get chosen as part of the cost-efficient low-carbon heat

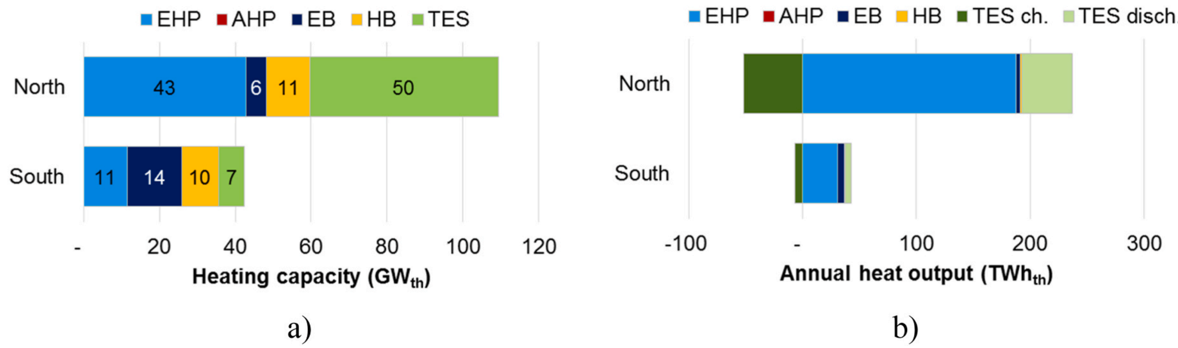

Fig. 3. Cost-optimal configurations of low-carbon heating portfolios for North and South systems: a) heating capacity in GW$_{th}$, and b) annual heat output in TWh$_{th}$.

portfolio in any system. Its investment cost is assumed to be about twice as high as the cost of H_2 boilers, and slightly higher than the cost of EHP, while its efficiency is lower than the COP of EHP, and the cost of producing hydrogen tends to be higher than the cost of producing electricity from low-cost renewables. All of these factors, in addition to the fact that EHPs are assumed available for investment in all investigated scenarios, make AHPs an unattractive proposition under these cost assumptions. All other heating options get chosen (in various proportions) as part of the cost-optimal heating capacity mix. However, it is important to emphasise that AHPs have a better thermodynamic performance than HBs, which also results in lower operating cost. For instance, if hydrogen were to be considerably cheaper than electricity (beyond what is shown in the results of this study) [9] or if weather conditions were to be particularly colder [35], EHPs could potentially lose their advantage, and AHPs may have a significant role to play.

Secondly, the compositions of the cost-optimal low-carbon heat portfolios differ significantly between the North and South systems. As expected, the total combined heating capacity of all options corresponds to the peak heat demand level of a given system, as depicted in Fig. 2, i. e., 109 GW$_{th}$ in the North and 42 GW$_{th}$ in the South. Nevertheless, because of the much longer and more intense heating season in the North, its heat portfolio is much more dominated by EHPs, with 39% of total capacity, and TES with 45% of total capacity. Respective contributions in the South system are 27% for EHPs and 16% for TES. The share of EBs and HBs in the heat portfolio for the North system is considerably lower (5% and 10%, respectively), while in the South they represent a larger share of heat capacity: 34% for EHBs and 23% for HBs.

Although the relative contribution of EHPs to the heat capacity mix is only between one quarter and two-fifths, their contribution to the annual energy output is substantially higher, as shown in Fig. 3b. This is not surprising given that EHPs have the typical features of a baseload technology, with relatively high investment cost but low operating cost, driven by relatively low cost of electricity and high operating efficiency (i.e., COP). The observed shares of EHPs in total annual heat supply are 97% in the North and 83% in the South.

Although both TES charging and discharging are plotted in Fig. 3b, their net effect at an annual level is a relatively small amount of additional heat demand caused by TES roundtrip losses. Nevertheless, the contribution of TES to heat supply is significant, with 24% of heat supplied from TES discharging in the North and 15% in the South (acknowledging that this energy was stored using the heat output from EHP, EB or HB at other times).

Annual energy contributions from EBs and HBs are marginal in the North (below 3% of total heat supply when combined), while in the South there is a sizeable contribution from EBs (around 15%) but marginal from HBs (below 1%). This is driven by the availability of low-cost solar PV resources in the South, which, in conjunction with high PV utilisation factors, allow electricity to be produced at a relatively low cost, making EBs a more attractive option for providing peak heat than HBs, when compared to the North system.

3.2. Hourly operation of electricity system and end-use heat technologies

To illustrate how various electricity and heat production technologies operate on a shorter timescale, Fig. 4 shows hourly diagrams for electricity generation (left) and heat output (right) in the North (top) and South (bottom) systems over a winter week.

Variations in electricity generation and BESS operation in the North (Fig. 4, top left) are mostly driven by fluctuations in wind output, which are more pronounced on a daily than hourly timescale. For instance, lower wind output on day 3 of the week requires higher utilisation of CCGT and OCGT generators, while BESS operation during the week broadly follows the cycle of charging at night and discharging during peak demand hours. Heat supply diagram in the North (Fig. 4, top right) suggests that EHPs operate as baseload source of heat, supplemented by EB and HB output during peak heat demand hours. EHP output during the night and midday exceeds the heat demand, which allows for charging TES and then releasing stored heat to help meeting high demand peaks in the morning and evening. This avoids excessive increases in peak electricity demand, which would require high investment in additional generation, network and storage infrastructure.

Typical operating patterns in the South are different: the volume of BESS installed as well as its utilisation are much greater than in the North, and its daily cycle aims to utilise high PV output during the day for charging, and then discharge electricity during the evening and night (Fig. 4, bottom left). With respect to heat supply (Fig. 4, bottom right), the volume and utilisation of TES are significantly lower than in the North, although the operation of TES also follows a daily cycle where it discharges during morning and evening peaks in heat demand. EHPs operate as baseload source of heat, while charging TES occurs either during the night, by operating EHPs above the heat demand and storing excess heat in TES, or around midday, when abundant PV output is converted into heat using EHPs or EBs and stored in TES.

3.3. Impact of high battery storage cost and of heat demand diversity

This section investigates the impact of increasing the cost of BESS on the cost-efficient heating portfolio, while also quantifying the effect of various levels of diversity in heat demand on the cost-optimal portfolio. Fig. 5 shows the cost-optimal heat portfolios in the North and South systems for cases with high BESS cost and a range of coincidence factors that are lower than one (0.75, 0.50 and 0.25). All of these cases are plotted alongside the baseline North and South scenarios to allow for identifying key differences and similarities.

The effect of higher BESS cost on the cost-efficient heat portfolio is relatively minor. Increasing the cost of BESS by 50% has a notable impact on the portfolio of electricity generation technologies, by reducing the volumes of BESS and PV generation and increasing the capacity of wind and peaking thermal generation (as shown in Fig. 9). However, there is a relatively minor impact on the capacity of heat technologies. EHP capacity is unaffected both in the North and South.

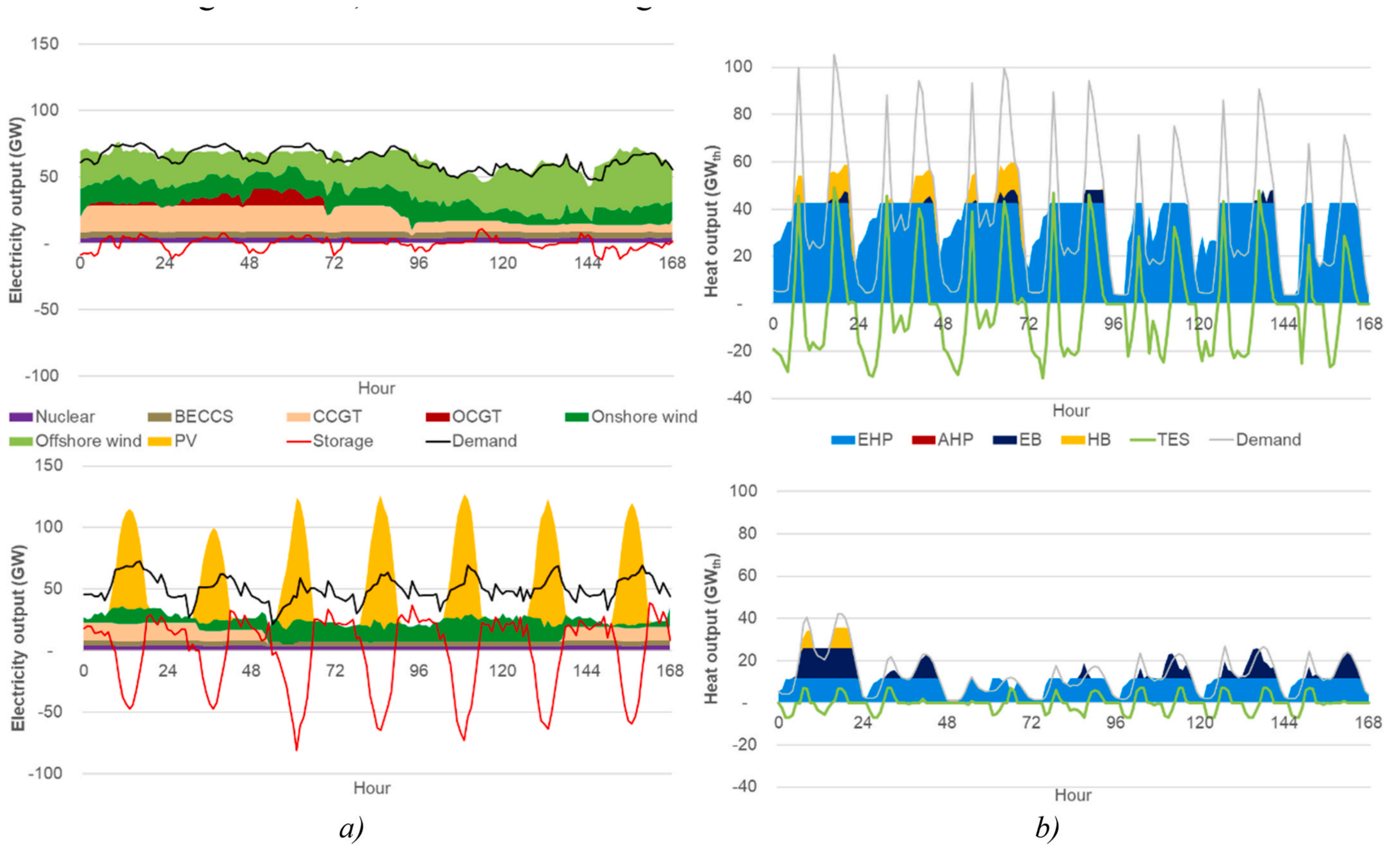

Fig. 4. Hourly operation of a) electricity generation and b) hourly heat output for baseline scenarios during a winter week in North (top) and South (bottom) systems.

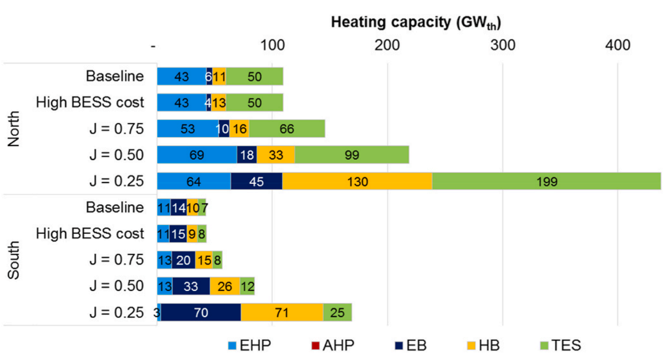

Fig. 5. Cost-optimal heating capacities of low-carbon heating portfolios for high BESS cost and various diversity scenarios in North and South systems.

Some of the EB capacity (about 2 GW_{th}) in the North shifts to HB, while in the South there is an opposite shift at the level of around 1 GW_{th}. TES capacity in the North does not change, while in the South it increases by about 1 GW_{th}, as high PV capacity in the South requires more flexibility, and with high BESS cost some of the flexibility is provided through installing additional TES capacity.

On the other hand, the impact of lower coincidence factors (J) on the heat capacity mix is substantial. This is not surprising given that reducing coincidence factors from 1 to 0.75, 0.50 and 0.25 effectively implies that the installed heating capacity needs to be 1.33, 2 and 4 times higher than diversified peak heat demand, respectively, as the non-diversified peak that needs to be met through heat technologies also increases by the same amount. It is interesting to note that as non-diversified peak increases to four times the baseline amount, the cost-efficient volumes of heating technologies do not scale up proportionately to peak increase. An exception to this is the TES volume in the North system, where it increases almost exactly in proportion to the increase in non-diversified peak demand, from 50 to 200 GW_{th}.

In the North, the EHP capacity initially increases with lower coincidence factors, however it reaches a ceiling at $J = 0.50$ given that its investment cost is the highest amongst all heating options (other than AHP that is never chosen) and is therefore inefficient to scale up given that its investment cost effectively increases in proportion to the increase in non-diversified peak demand. Its share of capacity drops from 39% in the baseline scenario to only 15% in the $J = 0.25$ scenario. At the same time, the missing heat capacity is made up by EBs and HBs, whose capacity increases by 8 and 11 times, respectively, as non-diversified peak increases 4 times.

Similar trends are also observed in the South system, where EHP drops from 13 to 3 GW_{th} as the coincidence factor reduces from 0.50 to 0.25. To compensate for that, the EB and HB capacities in the $J = 0.25$ scenario increase to 5- and 7-times higher levels than in the baseline, respectively.

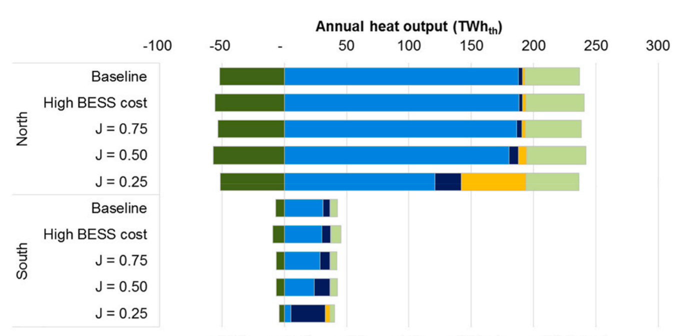

Fig. 6. Annual heat outputs of low-carbon heating technologies for high BESS cost and various diversity scenarios in North and South systems.

Fig. 6 shows the effect of high BESS cost and various diversity factors on annual supply of heat from low-carbon heating technologies. In the high BESS scenarios, there is very little change in the annual volumes of heat output from different low-carbon heat sources. In both North and South systems there is a slight increase in the utilisation of TES (reflected in higher volumes of both TES charging and discharging), which results from lower system flexibility due to reduced installed BESS capacity driven by its higher cost.

Similar to the capacity diagram in Fig. 5, the share of EHP in annual heat supply declines for lower values of coincidence factor, although this reduction is proportionately much slower than the reduction in capacity. In the North, the share of EHPs in heat supply drops from 97% in the baseline to 93% in the $J = 0.50$ scenario and 62% in the $J = 0.25$ scenario. At the same time, the combined contribution of boilers (EB and HB) increases from 3% (baseline) to 7% ($J = 0.50$) and 38% ($J = 0.25$). A similar, although even more extreme trend is observed in the South, where the share of EHPs reduces from 83% in the baseline to just 15% in the $J = 0.25$ scenario. Note that most of the heat displacing EHP output in the North is provided by HBs, while in the South this is supplied from EBs; this follows from a very low cost of electricity produced by solar PV generators in the South.

3.4. Impact of restrictions on availability of low-carbon heating technologies

This section investigates the impact of restricted availability of various low-carbon heating options on the cost-optimal portfolio. The following availability scenarios are covered by the case studies presented here:

- Baseline (all heating options available for investment)
- EHP only
- EHP and TES
- EHP and EB
- EHP and HB
- AHP and HB

Fig. 7 describes how the cost-efficient portfolios change in the presence of the above constraints and compares them to the portfolios obtained for baseline (unconstrained) North and South scenarios.

In the "EHP only" scenarios the solution is trivial, with the installed EHP capacity exactly equal to the peak heat demand (109 GW_{th} in the North and 42 GW_{th} in the South), as no other heating technology was assumed to be available for investment. If EHPs are allowed to be combined with TES, the installed capacity of TES in the North is the same as in the baseline scenario (50 GW_{th}), while the remaining heating capacity (60 GW_{th}) is provided by EHPs. This is not the case in the South, where the TES capacity in the EHP + TES scenario is significantly higher than in the baseline scenario (16 vs. 7 GW_{th}), while the EHP capacity increases almost threefold from the baseline (30 vs. 11 GW_{th}).

If EHPs and EBs are the only options available, the cost-optimal portfolio in the North consists of 70% EHP and 30% EB capacity, while in the South, with lower heat demand levels and relatively cheap electricity from solar PV the split between EHP and EB capacity is 38%–62%. When only EHPs and HBs are available for investment (being equivalent to "hybrid" HP solutions that include part standard EHPs and part hydrogen or even gas boilers), the model chooses a split of 58%:42% between EHPs and HBs in the North, and 45%:55% in the South. Finally, in case where only hydrogen heating options are available (AHP + HB), the solution in the North consists of 40% AHP and 60% HB capacity, while in the South the AHP vs. HB split is 29%:71%.

The impact of restricted availability of low-carbon heating technologies on annual heat output is quantified in Fig. 8. In all cases EHP was the dominant source of heat due to its favourable combination of cost and efficiency characteristics. In all cases except AHP + HB the share of EHPs in heat supply remained above 95% in the North, and above 83% in the South. In the AHP + HB scenario the bulk of heat is also provided by a more efficient heat pump technology, with 82–87% of heat supplied by AHPs and the remainder by HBs.

3.5. Annual supply of electricity and hydrogen

Cost-optimising the production of electricity and hydrogen for supplying low-carbon heating sector will result in some variation in the cost-efficient mixes of electricity generation and hydrogen production technologies.

Fig. 9 shows the annual electricity balance across all scenarios discussed in this section. All generation output figures are shown as positive values, while demand figures across different categories (basic demand, electric vehicles, cooling, heating, H_2 production) are shown as negative numbers in the chart.

For a given system (North or South) there is little variation in the composition of electricity supply across various scenarios. In the North about 70–72% of electricity is produced using wind, while in the South wind contributes with around 20% and solar PV with 53–54%. The remainder of electricity is produced by unabated gas generation (13–15%), nuclear (8%) and BECCS generation (6–7%), which has the role of offsetting emissions from unabated gas generation. A slight variation is observed in the South "High BESS cost" scenario, where more expensive battery storage makes solar PV a less attractive proposition, so its share in electricity supply drops to 37% while that of wind increases to 30%.

On the demand side one can observe variation in demand for EHP and EB operation across various scenarios, as well as differences in cooling demand between North and South systems. Most notably, the total volume of electricity reduces significantly in AHP + HB scenarios, where heating is provided exclusively with hydrogen technologies and hence there is no electricity demand for EHP or EB operation, while at

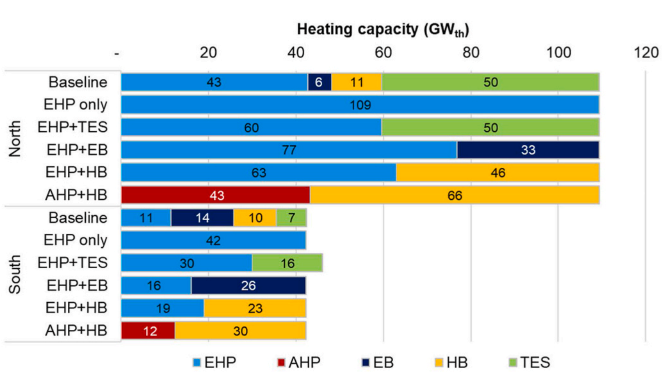

Fig. 7. Cost-optimal heating capacities for various combinations of available low-carbon heating technologies in North and South systems.

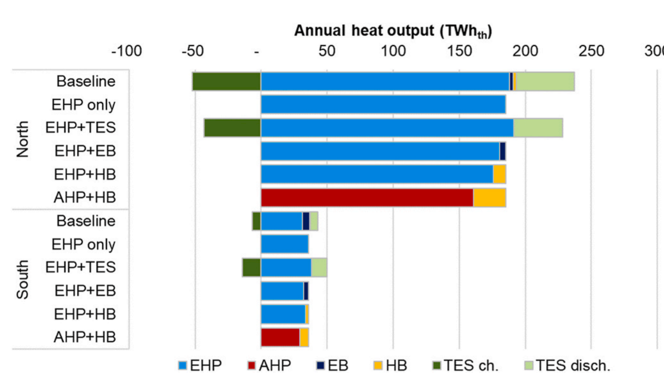

Fig. 8. Annual heat outputs for various combinations of available low-carbon heating technologies in North and South systems.

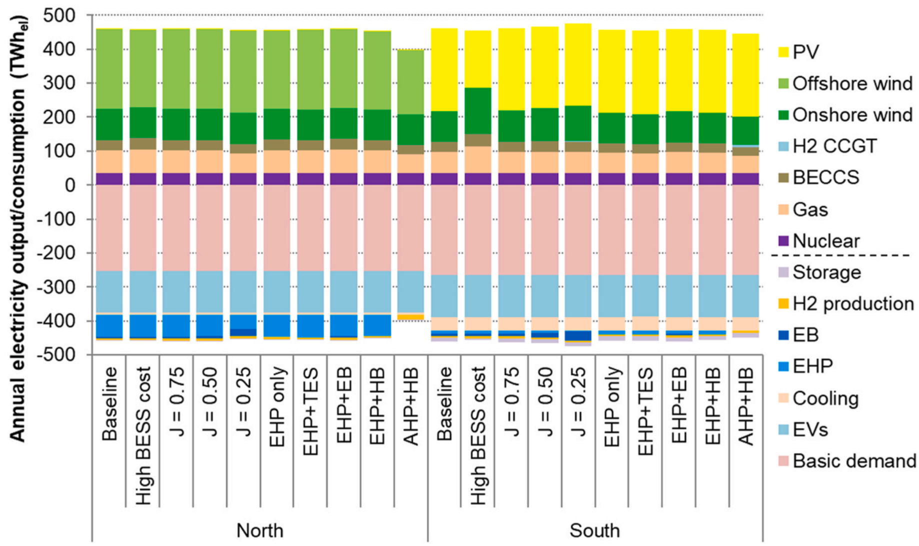

Fig. 9. Annual production and consumption of electricity across scenarios for North and South systems. Annual generation by various technologies is depicted as positive numbers while various categories of electricity demand are shown as negative values.

the same time there is an increase in electricity consumption for hydrogen production using SMR and ATR resources. Other demand segments do not vary across the system scenarios.

Annual production and consumption of hydrogen for all scenarios in North and South energy systems is depicted in Fig. 10. It is evident that the annual hydrogen balance is dominated by i) the production from ATR resources with CCUS, which account for 97–99% of total supply in the baseline North and South scenarios, and ii) the consumption by industry, transport and other non-heating sectors (denoted as “External demand” in Fig. 10), which is assumed to be fixed at 97.5 TWh per year.

Electrolysers and SMR resources with CCUS are generally not chosen by the model with the cost assumptions used in the analysis. Hydrogen imports, as the option with the highest variable cost, is only used to supply 2.6% of hydrogen in North baseline and 0.5% in South baseline scenario. More import is required in EHP + HB scenarios, at the level of 10% in the North and 3% in the South. Also, in the AHP + HB scenarios the volume of hydrogen produced and imported increases significantly above baseline, as large additional amounts of hydrogen need to be supplied for AHP and HP operation.

Changes from baseline results can be observed in those cases where significant proportion of heat is supplied through HBs, primarily $J = 0.25$ scenarios and EHP + HB scenarios, in both North and South systems. In those systems the heat output of HBs is not negligible and, given that HBs are used to supply peak heat demand (rather than a fixed hydrogen demand profile assumed for external demand, i.e., for industry), their use requires additional ATR capacity, and even some SMR capacity in the North $J = 0.25$ scenario. That scenario also features a considerable volume of hydrogen storage that is used to manage fluctuations in hourly hydrogen demand required for meeting heat demand peaks.

3.6. System cost differentials

Another modelling output that is interesting to study are changes in total system cost across different scenarios and their breakdown into different cost components associated with investments into assets in electricity, hydrogen and heating sectors. More specifically, system cost variations across the case studies presented in the study provide insights

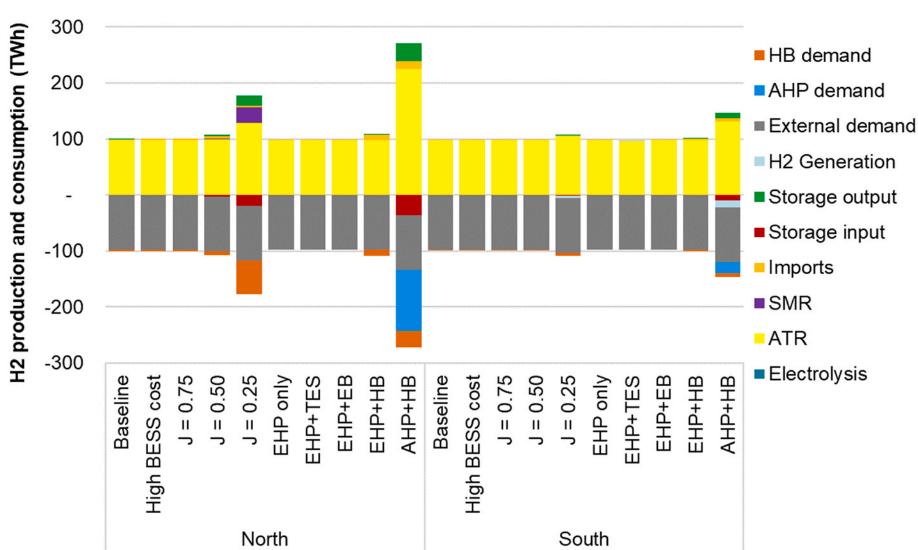

Fig. 10. Annual production and consumption of hydrogen across scenarios for North and South systems. Annual hydrogen supply from different sources is depicted as positive numbers while various forms of hydrogen demand are shown as negative values.

into the following questions:

- How much does the system cost increase if battery storage is available at a higher cost?
- What are the cost implications of various peak coincidence factors of heat demand?
- What is the penalty in terms of increased system cost in various cases of restricted availability of heating options, when compared to the fully optimised solution?

Fig. 11 quantifies the cost differentials across different scenarios calculated against the baseline scenarios for the North and South systems. Cost increments are shown broken down into individual cost components, as well as their net totals, as some cost components may reduce while others increase. As expected, all scenarios result in a higher system cost than the relevant baseline scenarios, given that they introduce additional constraints or increase the assumed cost of certain components compared to baseline scenarios.

System cost in the “High BESS” scenarios increases by £1.3bn/yr in the North and £2.3bn/yr in the South. Higher cost increase for the South system are the result of higher variability of PV generation, which dominates the electricity supply in the South; the system therefore requires a higher volume of battery storage in the South and is more sensitive to any increases in its cost. In the North the volume of BESS reduces from 87 to 48 GW_{el} when its cost increases by 50%, which is seen in the reduced total cost of BESS in Fig. 11. The model compensates for lower BESS capacity by adding more peaking generation capacity, the cost of which exceeds any savings in BESS cost and results in a positive cost increment. Similarly, in the South the BESS volume drops from 125 to 93 GW_{el}, which combined with a 50% cost increase results in a negligible change in the BESS cost component. On the other hand, the model decides to add more wind and less PV capacity as well as to increase the capacities of peaking generation and BECCS, all of which result in an increase in both generation investment cost and the cost of its operation.

It is also evident that the system cost increases with lower values of coincidence factors, as they effectively increase the requirements for peak heating capacity by up to 4 times. The increase in cost is much higher in the North system that is characterised by substantially higher levels of heating demand than the South, both in terms of volume and peak requirements. In the most extreme case with $J = 0.25$, the system cost in the North increases by £17.6bn/yr, and this cost increase results from increased investment into the four end-use heating technologies, as also seen in Fig. 5. This is supplemented by increased cost of hydrogen production and storage that is required to supply HBs in the most extreme case. The highest cost increase observed in the South system is £6.4bn/yr and is primarily the result of increased investments in EBs, HBs and TES (note that, as shown in Fig. 5, the EHP capacity in the South actually reduces at very low coincidence factors).

Finally, the system cost results for restricted combinations of heating options suggest the scale of increased system cost in case only one or two of these technologies were available for investment. Cost increments against the baseline are again more pronounced in the North system due to its much higher volume of heat demand. The highest values of incremental cost in the North are observed at £4.2bn/yr for the AHP + HB case, driven by higher AHP investment cost and higher cost of hydrogen production and imports, and at £3.0bn/yr when EHPs are the only allowed option, as their capacity needs to more than double from the baseline in order to meet peak heat demand. The restricted option with the lowest cost penalty is the one with EHP and TES, which results in a system cost increase of £0.5bn/yr. Combinations EHP + EB and EHP + HB result in system cost increases of £2.5bn/yr and £1.4bn/yr, respectively.

In the South system the cost penalties are smaller due to lower volume of heat demand. The highest cost penalties are again observed in the AHP + HB case (£1.2bn/yr) and in the EHP only case (£0.9bn/yr). The case that is the closest to the optimal solution is the EHP + EB, with the incremental cost of £232 m/yr, although that is closely followed by EHP + TES and EHP + HB scenarios with cost increments of £254 m/yr and £264 m/yr, respectively.

3.7. Levelised cost of heat

The final set of outputs focuses on quantifying the levelised cost of heat (LCOH). LCOH values are obtained by calculating the increase in total energy system cost between the proposed scenarios and benchmark scenarios that had no requirement for zero-carbon heat (i.e., where all heat requirements were met without the need for electricity or hydrogen, such as e.g., using natural gas). To obtain the LCOH, the incremental total energy system cost is divided by the annual heat delivered. LCOH therefore represents the incremental unitary cost required by the system to deliver zero-carbon heat, including both investment and operation cost at the supply side (i.e., related to electricity and hydrogen generation and storage technologies), plus the cost of

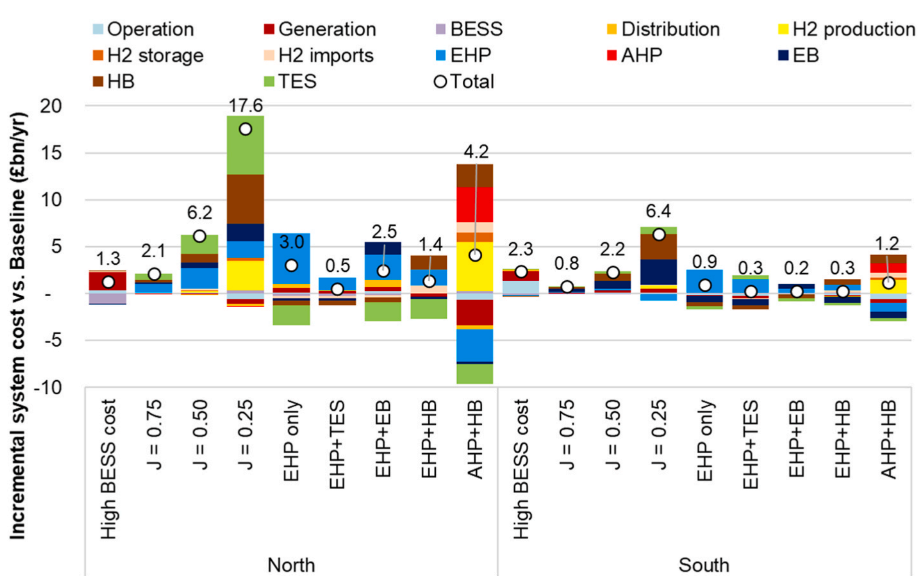

Fig. 11. Differences in total annual system cost between various end-use heat scenarios and relevant baseline scenarios for North and South systems.

installing end-use heating technologies.

The LCOH values across various scenarios are shown in Fig. 12. The chart also specifies the breakdown of LCOH into various cost components, same as the breakdown of total system cost discussed in Section 3.6.

The LCOH values are found to be lower in the baseline North system than in the South, due to the higher utilisation of EHP enabled by a higher heat demand and longer heating season. The LCOH in the North is £57/MWh$_{th}$, of which £23/MWh$_{th}$ is associated with the cost of supplying additional electricity and hydrogen, while £34/MWh$_{th}$ is the cost of installing end-use heat technologies (EHP, EB, HB and TES). In the South system the total LCOH value of £86/MWh$_{th}$ consists of £20/MWh$_{th}$ as the cost of energy supplied by the system and £66/MWh$_{th}$ as the cost of heating capacity. The latter component is significantly higher than in the North as the cost of heating capacity per unit of delivered heat in the South increases due to lower utilisation of this capacity.

High BESS scenarios are found to increase the LCOH compared to baseline scenarios, although significantly less in the North (+£7/MWh) than in the South (+£64/MWh). The South system relies considerably more on BESS flexibility to cost-effectively integrate electricity from inexpensive solar PV generation. Therefore, higher BESS cost in the South system results in a significantly higher levelised cost of electricity for EHP and EB operation.

Reducing the coincidence factor is found to increase the LCOH, which is expected given that the required low-carbon heating capacity is inversely proportional to the coincidence factor. Nevertheless, the increase in LCOH is not directly proportional to the increase in peak heat demand, as the heating technology mix adjusts to lower coincidence factors (as discussed in Section 3.3). Also, the cost components of LCOH associated with delivering energy (electricity or hydrogen) required for zero-carbon heating are found to be less sensitive to variations in heat demand diversity. For instance, in the North the components associated with the cost of energy in LCOH only change from £23/MWh to £25/MWh when coincidence factor reduces from 1 to 0.5, while at the same time the LCOH components associated with heating capacity increase from £34 to £65/MWh$_{th}$.

Finally, scenarios with restricted availability of heating technologies are predictably characterised by higher LCOH values. For the North system the lowest LCOH increase is seen in the EHP + TES scenario (by only £2/MWh$_{th}$ vs. baseline), and the highest in the AHP + HB scenario (by £22/MWh$_{th}$) and in the "EHP only" scenario (by £16/MWh$_{th}$). In the South system on the other hand, the lowest LCOH increase is observed in the EHP + EB scenario (+£6/MWh$_{th}$), although this is very close to the cost increments found in the EHP + TES and EHP + HB scenarios. The highest increase in the South is recorded in the AHP + HB and "EHP only" scenarios with LCOH £33/MWh$_{th}$ and £25/MWh$_{th}$ higher, respectively, than the baseline value.

4. Discussion

The results of the energy system modelling suggest that the cost-efficient portfolio of low-carbon heating technologies would involve four different technologies: EHPs, EBs, HBs and TES. The hydrogen-fuelled AHP was not chosen in most studies due to its relatively high investment cost, with the exception of restricted availability scenarios where the model was only allowed to invest in hydrogen heating technologies. The exact proportions of the four technologies in terms of both heating capacity and annual volume of heat were found to vary depending on system properties such as the availability of renewable generation and volume and diversity of heat demand.

In most cases, EHPs deliver the bulk of annual heat demand (97% in North and 83% in South baseline scenario), although their share of capacity was much smaller (39% in the North and 27% in the South) due to their relatively high cost per unit of heat output capacity and low running cost. Any residual peak heat demand was supplied by a mix of EBs, HBs and TES capacity in different proportions depending on the system characteristics: 5%, 10% and 45% in the North, and 34%, 23% and 16% in the South, respectively.

The main difference between heat technology mixes in the North and South systems is in the volume of required heating capacity, which is significantly higher in the North. In both systems the EHPs were the main source of heat, although in the South there was a significant share of heat provided by EBs (around 15%), enabled by relatively lower cost of electricity in the South available from inexpensive solar PV generation.

The results of the analysis quantify the cost-efficient heat technology mix at the level of the whole energy system. Obviously, it would not be feasible to simply scale this solution down to the level of individual properties. Instead, the actual choice of individual heating system configuration would reflect the local circumstances for a given property. For instance, it may be efficient to install HBs in smaller properties that are subject to space constraints that prevent them from installing EHP systems, or to use boilers as part of hybrid EHP + HB solutions where there are constraints in the local electricity distribution network. Similarly, some of the TES capacity, which the modelling suggests would be an efficient option, could be installed at the individual property level, while in other cases TES might be best implemented as a common asset serving multiple properties (such as e.g., flats in multi-occupancy buildings). Nevertheless, the results strongly point to a balanced mix of heating solutions as the most efficient pathway, with most heat supplied through EHPs and other technologies used to meet heat demand peaks.

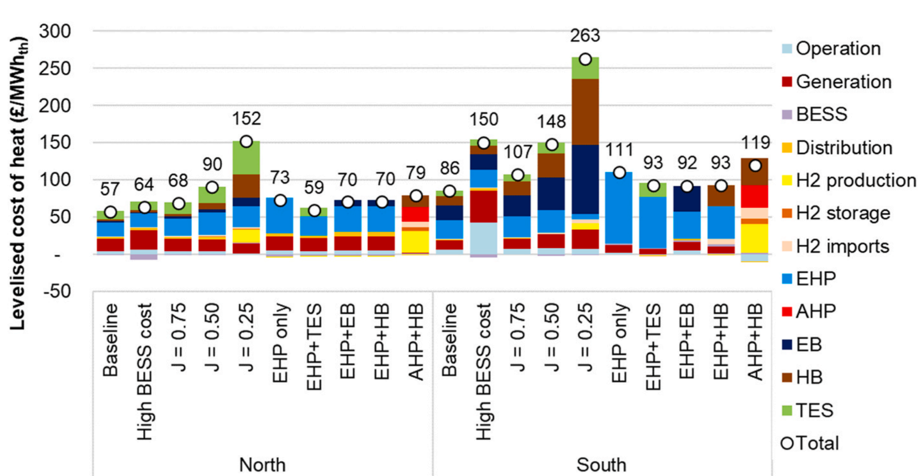

Fig. 12. Levelised cost of heat for various end-use heat scenarios for North and South systems.

When testing the sensitivity of the solution to variations in key assumptions, it was found that a 50% increase in the cost of battery storage had very little effect on the cost-optimal mix of heating technologies. The main change triggered by higher BESS cost was a slightly more intense utilisation of TES, given that the model decided to install less battery storage resources and therefore had less flexibility available in batteries.

Reducing the assumed level of coincidence factor for heat demand from 1 in the baseline scenarios to 0.25 expectedly resulted in an increase in installed heating capacity that was inversely proportionate to the reduction in coincidence factor (e.g., the coincidence factor of 0.25 meant that the system required 4 times more installed heat capacity to be able to meet peak demand). Nevertheless, the modelling results suggest that the increase in total heat capacity should not be simply achieved by proportional scaling of the baseline heating portfolio.

Lower coincidence factors effectively change the relative proportion of investment vs. operation cost for different heating technologies, making EHPs with their high investment cost relatively less attractive. As a result, the share of EHPs reduces with lower coincidence factors. For instance, with a coincidence factor of 0.25 the share of EHP capacity in the North drops from 39% in baseline to 15%, and in the South from 27% to only 2%. In the North EHPs remain the largest source of heat even with low coincidence factors, although their share in annual heat supply drops to 62%, which is compensated by increased output of HBs and EBs. In the South system, on the other hand, the EHP output with the lowest coincidence factor drops to just 15% of annual heat supply, and the majority of heat supply is taken over by EBs.

The final set of case studies quantified the cost-efficient portfolios of heating technologies if only a subset of them was available for investment, i.e., if EHPs were the only available options, if they were allowed to be coupled with just one more technology (TES, EB or HB), or if only hydrogen technologies (AHP and HB) were available for investment. The AHP + HB scenario required the highest increase in system cost in order to supply the heat demand, which resulted from higher investment cost in AHP and higher cost of hydrogen production and imports. The "EHP only" scenario resulted in the second highest incremental cost for both North and South systems, as it required that high-cost EHP capacity matched the peak heat demand. In the North system the most favourable restricted combination of heating technologies was EHP + TES, resulting in only £0.5bn/yr system cost increase relative to the fully optimised heat solution. In the South, with relatively cheap electricity available from solar PV resources, the most cost-efficient combination of two technologies was EHP + EB, although its cost penalty was only marginally lower than for EHP + TES and EHP + HB combinations. In both systems, the only case when the model suggested investing in AHP capacity was when investment was only restricted to hydrogen heating technologies, i.e., if electrification of heating was not an option.

The analysis presented in this work also quantified the LCOH across various scenarios. The observed values of LCOH were lower in the North system than in the South, with baseline values of £57/MWh_{th} and £86/MWh_{th}, respectively. This difference was driven by a higher utilisation of EHP capacity in the North due to higher heat demand and longer heating season, which resulted in a lower cost of installed heating capacity per unit of delivered heat than in the South.

It is worth noting that any changes in the volume and variability of heat demand, such as those driven by increasing global temperatures as a result of climate change or by improvements in building thermal insulation levels, would also likely change the cost-optimal portfolios of low-carbon heating options identified in this research. Drivers such as climate change and insulation improvements can be expected to affect not just the installed volume of low-carbon heating options, but also their relative proportions in the portfolio. In particular, there is a very large potential for demand reductions through buildings retrofit [55], which should be considered simultaneously with decisions to invest in various zero-carbon heating technologies to identify cost-efficient trade-offs between reducing demand and decarbonising heat supply. The authors intend to address these considerations in their future work.

5. Conclusions

This study proposed a quantitative energy system modelling approach to determine cost-efficient composition of integrated low-carbon heating solutions from the system perspective. The objective of the model was to minimise total energy system cost concurrently with the cost of investing into a portfolio of customer-level low-carbon heating technologies.

This technology-to-systems approach involved the use of comprehensive thermodynamic and component-level costing models of various heating technologies, which informed the whole-energy system optimisation model. This allowed for identifying cost-efficient system-driven designs of low-carbon heating systems based on electricity and hydrogen that result in lowest overall energy system cost when heat supply is optimised alongside electricity and hydrogen supply systems.

Case studies presented in this work were based on two archetypal energy systems (North and South), which had different characteristics with respect to the volume of heat demand and the utilisation of renewable generation technology. Modelling results suggest that a cost-efficient solution for zero-carbon heating consists of a portfolio of low-carbon heating technologies including EHPs, EBs, HBs and TES, while AHPs were found to be less attractive due to their high investment cost. The capacities of the four heating technologies were found to vary significantly depending on key system characteristics such as the volume and diversity of heat demand and the availability profiles of renewable generation.

Using archetypal systems in this analysis allows the results to be mapped onto many countries or regions globally, rather than just assess a single national system. The approach to system-driven design of technology portfolios presented in this work can be extended to many other examples. A recent study of system-led design of flexible nuclear plant configurations is presented in Ref. [56].

Future work in this area will focus on differentiating between different types of low-carbon end-use technologies trading off high-cost but high-efficiency solutions against low-cost and low-efficiency, as well as studying the impact of different TES durations. Impact of fuel price variations, as experienced recently for natural gas, will also be explored in more detail. More analysis will be required to adequately address the relationship between the installation sizes of different technologies and their investment cost per unit of capacity. Furthermore, as energy system cost-optimisation models are sensitive to relative prices of different technology options, incorporating technological learning while accounting for uncertainty in the optimisation models would be a valuable direction for future research.

Given the high sensitivity of the heat resource portfolio on the coincidence factor, more work will be needed to better understand the diversity of heat demand under different weather conditions including extremely cold spells. Attention will also need to be given to issues associated with electricity and hydrogen distribution grids and their costs. Unlike the connections to the electricity distribution network that are already in place for virtually all customers, the additional cost of developing hydrogen supply networks and connecting households could be significant, especially if there is no gas distribution network available that could be repurposed for hydrogen distribution.

Further research is also needed to understand the potential role district heat networks could play in cost-efficient decarbonisation of heat supply. Heat networks represent a viable heat decarbonisation pathway, particularly in high heat demand density areas with available low-carbon waste heat sources. Assessing district heating as an option will require spatially disaggregating the energy system model and identifying demand clusters as well as waste heat availability areas and local constraints.

Finally, it needs to be established under which conditions conventional gas boilers could also be used as part of cost-efficient future heat portfolios if carbon offsets were available to compensate for their emissions.

CRediT authorship contribution statement

Marko Aunedi: Conceptualization, Data curation, Formal analysis, Methodology, Software, Validation, Visualization, Writing – original draft, Writing – review & editing. **Andreas V. Olympios:** Data curation, Formal analysis, Methodology, Software, Validation, Visualization, Writing – original draft, Writing – review & editing. **Antonio M. Pantaleo:** Conceptualization, Formal analysis, Methodology, Writing – review & editing. **Christos N. Markides:** Funding acquisition, Methodology, Project administration, Resources, Supervision. **Goran Strbac:** Conceptualization, Funding acquisition, Project administration, Resources, Supervision.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Marko Aunedi reports financial support was provided by Engineering and Physical Sciences Research Council.

Data availability

Data will be made available on request.

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