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Estudio de sensibilidad de parámetros en el diseño y dimensionado de centros de producción de energía

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TÍTULO: **Optimization, design and hourly operation schedule of a centralized district energy centre and sensitivity analysis assessment based on an East London case study**

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RESUMEN

Ante las crecientes preocupaciones acerca de las emisiones de CO2, los sistemas energéticos urbanos (DE) se presentan como una solución para la decarbonización de las economías. Dado que no existe una metodología sistemática para el diseño de DE, este TFM presenta el modelo ECS (formulación MILP), capaz de determinar la combinación óptima de tecnologías centralizadas así como su operación para unos determinados requerimientos energéticos. Dicho modelo es aplicado para evaluar la influencia de diferentes parámetros en la operación y diseño de centros energéticos, tomando un caso práctico (este de Londres) como referencia. Se demuestra la importancia de la exportación de electricidad para la viabilidad económica del sistema además de la no-rentabilidad de calderas de biomasa o HP en ausencia de RHI. Las emisiones carbónicas y el área requerido por el centro pueden reducirse respectivamente hasta un 50% y 20% comprometiendo el beneficio anual tan solo un 15% y un 2%.

PALABRAS CLAVE

1) Sistemas energéticos urbanos (DE)
2) Optimización, diseño y planificación de la operación
3) Selección de la tecnología
4) Estudio de sensibilidad
5) Programación linear entera mixta (MILP).

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Optimization, design and hourly operation schedule of a centralized district energy centre and sensitivity analysis assessment based on an East London case study

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ABSTRACT

Given the global concerns related to the greenhouse emissions and the climate change and taking into account the current challenges to reduce the energy consumption and to change the energy infrastructure (intermittent nature of renewable sources, lack of electricity storage, inaccurate weather forecast, etc.), the district energy schemes arise as a potential solution for the decarbonisation of the economies, especially in the UK. Since there is no systematic methodology to design DE centres, this paper presents the ECS model, formulated as a mix integer linear problem, which is able to determine the optimal centralized mix of technologies as well as the operation scheme provided certain energy requirements. The model is applied to assess the influence of different parameters in the DE centre design and operation, considering an East London case study as reference. The importance of electricity generation and export in the economic viability of the scheme is proved as well as the unprofitability of biomass boilers and HP in case that the renewable heat government subsidies are removed. Finally, carbon emissions and energy centre required can respectively be reduced up to 50% and 20% compromising the annual profit only 15% and 2%. The possibility of adding ORC modules to the CHP engines tripled the annual profit.

1. Introduction

Climate change and greenhouses emissions remain high concern for the global community. In consequence, several international policies and programs, such as the Kyoto Protocol and the Energy White Paper of the European Union, have been established in order to promote the decrease in CO_2 emissions and the use of renewable heat sources [1], [2]. Thus, the government of the United Kingdom has set an 80% greenhouse gas emission reduction, against a 1990 baseline, by 2050 and 15% of energy consumption from renewable sources by 2020 as medium and long term target [3]–[5]. However, there are still many challenges to face (intermittent nature of renewable sources, lack of electricity storage, inaccurate weather forecast, etc.) and not only a substantive reduction in energy consumption is needed but also significant changes in the energy infrastructure in the UK [1], [4], [6]. Taking into account that: 1) heat is the biggest use of energy in the UK representing a 46% of the final energy consumed; 2) three quarters of heat are consumed in households and in commercial and public buildings [6] and 3) heat is also responsible for 38% of carbon dioxide emissions in the UK [7], district heating (DH) and, in general, district energy (DE) schemes arise as a potential solution for the decarbonisation of the UK economy. A wide scale implementation of DH, where it is competitive, would help Europe reducing its greenhouse gases emissions to 80% below 1990 levels [8].

The joint energy production in the DE centres leads to a higher conversion efficiency and less maintenance cost. Moreover, the use of fossil fuels (natural gas in domestic boilers) can be displaced by many other energy sources increasing the flexibility of the energy system and reducing the carbon emissions [9], [10]. Additionally, low-temperature heat from renewable energy sources such as solar and geothermal energy, as well as industrial waste heat, waste incineration or power plant waste heat may be used to decrease the dependency to primary energy [4], [11], [12]. All this above mentioned helps to decrease the costs associated to heat production and addresses fuel poverty problems. Furthermore, from a costumers perspective, DE means there will be more available space in buildings and, since district heating is safer than classical domestic boilers, less property and liability insurance costs [13], [14]. In addition, district heating, by helping the deployment of CHP plants, has the potential to reduce the pressure on electrical network infrastructure and to offset additional electrical peaking plants. For these reasons, DE have recently received political support from the European Union (European Energy Efficiency directive [15]) and the UK (funding to contribute to local authorities costs over the first two years of the DE project [5] and Non-Domestic Renewable Heat Incentive [16]). The Energy Roadmap 2050 [17] highlights the potential of DH in the EU27 and identifies strategic heat synergy regions characterised by a large usable excess heat [7], [15], [18]–[23]. While the DE schemes are widely implemented in Scandinavia [24], Eastern Europe, Germany and Denmark [25], [26], DECC estimates that by 2030 up to 20% of UK domestic heat demand might be met by heat networks [5].

Among the wide range of primary and secondary technologies that can produce heat [9], [11], [13], [14], biomass and natural gas boilers, heat pumps (water, air, ground, etc.) and CHP, commonly powered by natural gas because of its availability and its low cost, are the most used technologies [14]. Additionally, thermal energy storage is usually needed to balance the demand and to match the heat production and consumption. The CHP technology, even though it is not a renewable heat source, leads to a significant potential reduction in carbon emissions thanks to its high energy

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generation efficiency (up to 85-90% [4]); the fuel energy power is used to produce electricity, which is potentially used to power the HP or is sold to the costumers, to the national or local electricity grid or to a secondary electricity market, and the leftover heat, which would otherwise be wasted in centralised systems, is distributed through a District Heating Network in form of hot water or steam [4], [12]. Moreover, the CHP technology can contribute to different electricity grid balancing mechanisms [27] and it has been proved to be almost essential for the economic viability of DE centre in UK; high economic incomes from electricity exports as well as great savings from avoiding grid electricity imports can be obtained using CHPs. Organic Rankine Cycle modules can be added to the CHP engines to improve the electricity production efficiency to the detriment of heat production efficiency [28].

However, DE networks continue being complex systems that precise understanding and their planning, design and operation need to be carefully investigated. Indeed, a systematic methodology to design DE centres does not exist when several technology options shall be considered [4], [10]. In these circumstances, modelling and optimisation approaches are essential to ensure a good system efficiency. As Weber et al. [1] pointed out, the design and optimization of DE system including one or more technologies to satisfy the energy demand is extensively studied by many authors. The literature review provided by Oluleye et al. [4] and by Connolly et al. [29] are deeply recommended to gain an insight in DE modelling [1]. Three major types of models can be found [30]–[38]: 1) models focused on the technology selection, equipment sizing and network distribution; 2) models that consider the network essential parameter design (supply temperature selection, determination of pipes diameters, etc.) and 3) models dealing with network operation (temperature, mass flow rate, etc.), usually for a DE layout given. In most cases linear programming is preferred.

Elaborating and complementing the existing models, a mix integer linear programming (MILP) model has been developed not only to determine the optimal centralized mix of technologies but also to define the operation scheme according to given energy requirements; the Energy Centre Synthesis Model (ECS). Apart from several operational constraints, as novelty, the model follows a granular hourly approach, which allows a real track of the thermal storage level, is able to consider continuous and discrete size technologies, presents several methodologies to calculate the annual carbon emissions and is completely flexible regarding the optimization criteria (maximum annual profit, minimum required area, minimum annual emissions, etc.). Thus, the aim of this paper is to define and describe the Energy Centre Synthesis Model and to apply it to assess the influence of different parameters into the optimal mix of technologies and the consequent optimal operation strategy: electricity and gas price, electricity secondary market and electricity external demand existence, renewable heat incentive government subsidy, energy centre required area and heat sources availability.

2. Description of the Energy Centre Synthesis Model

The purpose of the Energy Centre Synthesis Model is to define the centralized mix of technologies as well as the consequent early operation scheme that will best meet the energy service requirements (heat and electricity) of certain area under study. The optimization criteria, defined by the objective function, are completely flexible. Thus, multiples strategies from maximum profit, minimum carbon emissions, minimum centre area required, etc. to a mix of all of them can be assessed in order to determine the optimal technology selection.

Assuming heat to be the main energy requirement, the technologies considered in the model are combined heat and power engines (CHP) with and without organic Rankine cycles modules (turbines using CHP heat) (ORC), biomass (biomass) and natural gas (boiler) boilers, heat pumps (HP) and thermal energy storage (TES). While the size of biomass and natural gas boilers, heat pumps and thermal storage is a continuous variable, the size of the combined heat and power engines and their corresponding ORC modules is restricted to discrete values. This formulation aims to reflect the fact that whereas storage and boilers of almost any size can be purchased, the set of commercial CHP sizes is more limited and standardised. On the other hand, in several cases large capacity centralised heat pumps are custom-made. Therefore, their size have also assumed to be continuous variables. Any combination of these technologies can be selected and, in addition, different technologies (wind turbines, solar thermal collectors, PV cells, fired turbines, etc.) can straightforwardly be added or removed as well as the technology size continuity assumption modified, according to the problem to be solved (i.e. electricity as main energy requirement).

The model considers two different types of energy demand that must be met anytime: heat and electricity. The heat demand is generated by the potential necessities of space heating and

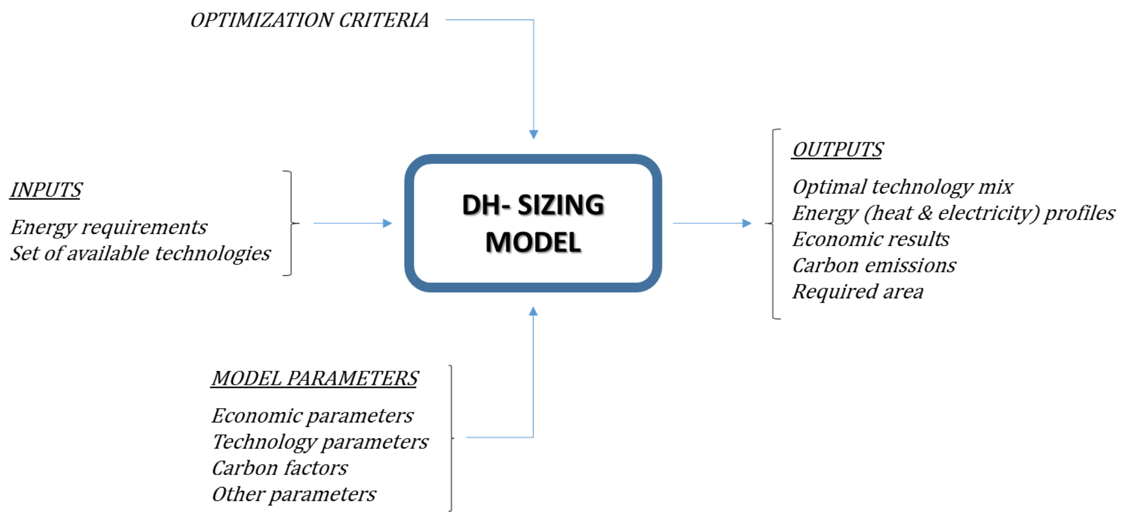

Fig. 1. Diagram summarising how the ECS model works and which are its main inputs, outputs and parameters.

domestic hot water (DHW) of the users connected to the district heating network (DHN). This demand can be satisfied either by the selected technology units or by heat available from an external source (waste heat, solar heat, etc.). The electricity demand is disaggregated into internal and external electrical demand. While the first one refers to the normal operation of the heat network and energy centre (water pumping, lighting, etc.), the second one is a consequence of the hypothetical activity of the energy centre as electrical provider to private users. In addition, there may be a third (internal) electrical demand corresponding to the use of heat pumps to generate heat. To meet the aggregate electrical demand, electricity can be produced by the technology mix selected (CHP and CHP with ORC) and imported from the grid. In this study only heat storage is considered. However, electricity in excess can be sold to either to the grid or to a secondary electricity market. Cooling energy requirements can easily be added just by following the heat energy structure.

To help addressing in a more accurate way the question of which combination of energy technologies will be best suited to meet the energy services required and how these technologies will be operated, the ECS model considers several size and operational constraints. Concretely, maximum technology capacity and maximum available energy centre area size constraints are taken into account as well as maximum carbon emission intensity, maximum carbon emissions per year, maximum secondary electrical market capacity, minimum part loads[1], minimum running hours between shut-downs and, among others, CHP night noise operational constrains are also implemented in the model.

Contrary to other similar district heating models such as the one presented by C. Weber and N. Shah [1] or the one proposed by C. Haikarainen et al. [39], in the ECS model the energy demand data (as well as the rest of the parameters) is not discretised. That is, a granular hourly approach is followed and all the 8760 time periods of the year are considered. Even though this may increase the complexity of the framework as G. Oluleye et al. [4] pointed out, the quality of the optimization results is not compromised at all and the storage can be properly modelled (hourly tracking of the level from one time period to another). This multi-period approach, linked to the mixed consideration of continuous and discrete technology sizes, the technology area requirements and constraints and the flexibility of the objective function, are the key novelties featured in the presented model. In addition, the three carbon accounting methodologies proposed by the Department of Energy & Climate Change (DECC) [40] are considered in the model in order to calculate the carbon emissions.

Fig. 1 describes the main inputs, parameters and outputs of the model. Once both the optimization criteria and the parameters are set, the model is able to compute the optimal technology selection mix, the hourly heat and electricity production profiles, the carbon emissions, the required surface area and economic KPIs (OPEX, CAPEX, profits, etc.) for a given energy requirements and set of candidate technologies. The parameters of the model can be grouped into four categories: price parameters, including the price of the heat, the electricity and the different fuels as well as the government subsides; technology parameters, such as energy efficiencies, parts loads, investment cost, maximum sizes, etc.; carbon factors[2] of the grid and of the different fuels; and other parameters that do not fit in the groups mentioned above (Carbon emissions limits, area constraints, etc.). Regarding the energy profiles, they give detailed insights on how the demand is met hour by hour, providing information about heat and electricity production (by every technology selected), electricity imports and exports and storage level. In addition, the load duration curve can be built from these profiles to summarise the yearly heat production.

3. Mathematical formulation

Given the current optimization techniques, unlike linearly formulated problems in which the convergence to the optimal global solution can be ensured, the same cannot be guaranteed for non-linear problems. Additionally, the convergence is usually faster in linear problems. Thus, linear formulation has been preferred for the ECS model. In practical terms, similarly to the approach followed by G. Oluleye et al. [4], the model has been formulated as a superstructure, including all the technologies and equipment available, from which the optimal solution is synthesised. Hence, binary variables are included to express the existence, or not, of each unit in the final solution as well as the activity, or inactivity, of those technologies in each time period. The resulting formulation itself is typical of a mix integer linear problem (MILP).

In the case of the CHP technology and ORC modules, whose sizes are considered discrete as it was mentioned in the above section, each unit type, or discrete size value is repeated several times within the superset to enable the selection of more than one unit of each type. Regarding the rest of the technologies (TES, HP, gas and biomass boilers), their investment costs entirely depend on the size of the technology, existing no differences in cost nor efficiencies between one unit of a certain size and two units of half the considered size. The only difference in global system performance that could arise by duplicating those technologies would come from minimum part load constraints: by disaggregating certain technologies, their global minimum part load is implicitly lowered. For this reason, taking into account that the thermal storage, heat pumps and gas boilers already have a quite low or even no minimum part load (see Table 1), the approximation of not duplicating these units seems to be reasonable in order to simplify the problem. However, biomass boilers technology, whose minimum part load is relatively high if thermal efficiencies similar to gas boilers are required to be achieved, has been duplicated.

The main equations, subject to which the superset proposed is reduced during the optimization, are listed below (see the nomenclature section). The key decision variables concern the type and size of the technologies and the operating strategy of the technologies.

3.1. Objective function

The flexible optimization criteria previously mentioned comes from the different formulations in which the objective function can be defined. Actually, infinite theoretical optimization strategies can take place since any linear combination of model variables can be used to define the objective function (as a weighted sum defining a multi-objective problem). For this study, a profit driven strategy is mostly used:

[1] Referring to the part per unit or percentage of heat output of a certain unit respect to its maximum heating capacity. This connotation of the term *part load* applied to all sections

[2] CO_2 equivalent emissions per energy consumed. Typically expressed as $KgCO_2e/kWh$ or gCO_2e/kWh.

Table 1
Cost parameters, factors and asset lifetimes of each technology. Note: The asset lifetime for ORC modules and biomass boilers has been approximated as the CHP and natural gas boilers ones in absence of data. Biomass boilers can operate at lower part load but their thermal efficiency is highly compromised.

Technology	Asset lifetime, N_i [[$year$]	Invest. Fixed Costs, C_i^{Fix} [£]	Invest. Var. Costs, C_i^{Var} [$kWth$/£]	Operation and maint. factor, F_i [%]	Fixed annual maint. cost, $C_i^{Maint.}$ [£]	Minimum part load, κ_i [%]	Reference
Combined Heat and Power	15	*	0	0	*	70	[41]
Organic Rankine Cycles modules	15	*	0	0	*	70	[1], [41]
Heat Pump	25	0	1600	6	0	20	[1]
Biomass Boilers	15	0	133.25	16	0	70	[42]
Natural Gas Boilers	15	0	100	18	0	10	[1]
Thermal Energy Storage	15	0	33.11	1	0	0	[42]

*Investment fixed cost and fixed annual maintenance cost of CPH and ORC modules depends on the concrete unit and can be found in tables 7 and 8

$$\max\left[P^{TOT} = \sum_{t\in T} R_t^{OP} - \sum_{i\epsilon\Theta} C_i^{INV} - \sum_{t\in T} C_t^{OP}\right] \quad (1)$$

With P^{TOT} the total annual profit, T and Θ the set of time periods and available technologies respectively, R_t^{OP} the revenue resulting from selling heat and electricity to the network consumers at period t, $C_i^{INV}$the annual investment cost of technology i, and $C_t^{OP}$the total cost resulting from the operation of the plant at time t. Additionally, in some case studies presented in the following section, minimum carbon emissions and minimum required area criteria are used. Furthermore, other strategies such as minimum gas or electricity consumption, maximum electricity production or multiple objective strategies may be interesting.

3.2. Profit, Cost and Revenue functions

As Eq. (1) shows, the total annual profit is equal to the revenue obtained by meeting the energy requirements minus both the operational and the investment cost. The revenue, balance of the heat and electricity network end-user consumptions, is calculated as follows:

$$R_t^{OP} = \frac{1}{1000}\left[D_t^{Elect,EXT} \cdot p^{Elect,EXT} + D_t^{Heat} \cdot \sum_{k\in\Phi} p_k^{Heat} \cdot \chi_k\right] \quad \forall t \in T \quad (2)$$

With $D_t^{Elect,EXT}$the external (network costumers) electricity demand for the scheme at time t, $p^{Elect,EXT}$ the external electricity demand price, D_t^{Heat} the total heat demand (DHW and space heating) for the scheme at time t, Φ the set of costumers (community, commercial, NHS, other public and other costumers), $p_k^{Heat}$the heat price for costumer k, and χ_k the parts per unit of costumer k within the scheme according to the heat consumption. The factor 1/1000 is used for consistency of units.

The investment costs for all technologies are computed following the general equation proposed by C. Weber and N. Shah [1] with some modifications to include no-investment dependent maintenance cost:

$$C_i^{INV} = \frac{M_{2016}}{M_{0,i}}\left[(1+F_i)\cdot An_i \cdot \left(C_i^{Fix}\cdot X_i + C_i^{Var}\cdot S_i\right) + C_i^{Maint.} \cdot X_i\right] \quad \forall i \in \Theta \quad (3)$$

With M_{2016} the Marshall & Swift[3] factor for the year 2016, $M_{0,i}$ the reference Marshall & Swift factor of the year for which the investment cost factors and parameters of technology i are known, F_i the maintenance factor of technology i (investment dependent maintenance costs), An_i the annuity factor of technology i, C_i^{Fix} the investment fixed costs of technology i, C_i^{Var} the investment variable (size dependent) costs of technology i, $C_i^{Maint.}$ the fixed (no-investment dependent) annual maintenance cost of technology i, S_i the size of technology i, and X_i a binary decision variable equal to 1 if unit i exists.

While the maintenance factor is introduced for approximating the maintenance cost of the continuous-size units (HP, biomass boiler units, natural gas boiler and storage), the fixed annual maintenance cost parameter has been introduced to account for the maintenance costs of the discrete size units in a more accurate way. The annuity factor is calculated as follows:

$$An_i = \frac{r\cdot(1+r)^{N_i}}{(1+r)^{N_i}-1} \quad \forall i \in \Theta \quad (4)$$

With r the interest rate and N_i the asset lifetime for technology i. The cost parameters, factors and lifetimes of the different technologies can be found in table 1.

As Eq. (5) illustrates, the operational cost are disaggregated into two groups: CHPs, HP and electricity cost related ($C_t^{CHP,HP,Elect}$) and boilers operational costs ($C_t^{Boilers}$). The thermal storage operational costs mainly relate to the electricity consumed for pumping, which is included into the internal electricity demand and, therefore, results in CHP electricity production and grid electricity imports costs. Hence, the storage cost are already indirectly accounted into the first group of operational costs.

$$C_t^{OP} = C_t^{CHP,HP,Elect} + C_t^{Boilers} \quad \forall t \in T \quad (5)$$

[3] The Marshall and Swift Cost Indexes, M&S, are dimensionless numbers used to updating capital cost required to build an industrial plant from a past date to a later time, following changes in the value of money due to inflation and deflation. Alternatively, the Chemical engineering Indexes, CE, can be used. Both systems were stablished with an initial value of 100, the first one in 1926 and the second one in 1957-1959.

This first group consists of the grid electricity imports (to satisfy the internal, external and HP electricity demand) and the CHP, with (Ω set) and without ORC modules (Ψ set), fuel costs, discounted cash flows accounting for heat pumps renewable heat incentives and electricity exports to the grid and to the secondary electricity market:

$$C_t^{CHP,HP,Elect} = \frac{1}{1000}\left[G_t^{CHP} \cdot p_t^{gas} + E_t^{grid\rightarrow DH} \cdot p_t^{grid,buy} - E_t^{CHP\rightarrow grid} \cdot p_t^{grid,sell} - E_t^{CHP\rightarrow Market2} \cdot p_t^{Market} - Q_t^{HP} \cdot p_{HP}^{RHI}\right] \quad \forall t \in T \tag{6}$$

With G_t^{CHP} the natural gas consumed by the CHP units, with and without the ORC modules, at time t, $E_t^{grid\rightarrow DH}$ the electricity purchased from the grid at time t, $p_t^{grid,buy}$ and $p_t^{grid,sell}$ the grid electricity import and export price at time t, $E_t^{CHP\rightarrow grid}$ and $E_t^{CHP\rightarrow Market2}$ respectively the electricity generated by the CHP and sold to the grid and to the secondary market at time t, p_t^{Market} the secondary Market electricity export price at time t, and p_{HP}^{RHI} the renewable heat incentive subsidy for heat pumps. As mentioned before, the factor 1/1000 is used for consistency of units.

Whereas the relation between the thermal or electrical efficiency and the part load of the CHP and CHP with ORC units is non-linear, linearity between natural gas consumption (as well as power output) and part load has been proved for all the engines (R-square values greater than 0.999). Thus, the total CHP and ORC-CHP natural gas consumption are calculated as:

$$G_t^{CHP} = \sum_{i\in(\Psi\cup\Omega)} \left(\frac{Q_t^i}{S_i^{Max}} \cdot a_i + b_i \cdot y_t^i\right) \tag{7}$$

With Q_t^i the heat produced by technology i at time t, S_i^{Max} the maximum size of technology i, a_i and b_i the slope and the independent term of the linear fuel consumption function depending on the part load for unit i, y_t^i a binary variable equal to 1 if unit i is being used at time period t. Note that the size of the CHP and ORC-CHP units is equal to the maximum size (See Eq. (16)) and, therefore, part loads are being calculated in Eq. (7). The a_i and b_i coefficients can be found in table 8.

Table 2
Average value and dispersion of the ratio electricity carbon factor - natural gas carbon factor considering all the CHP with and without ORC modules operating in a range of part load between 50 - 100% and between 75 - 100%.

DECC Methodology		CHP operation part load: 50 - 100%	CHP operation part load: 75 - 100%
1/3:2/3 Method	Mean Value	1.534	1.531
	Standard deviation	0.053	0.059
Boiler Displacement Method	Mean Value	1.124	1.138
	Standard deviation	0	0
Power Station Displacement Method	Mean Value	2.096	2.096
	Standard deviation	0.000	0.000

The second operational costs group accounts for the biomass and boiler natural gas consumption and the biomass renewable heat incentives as follows:

$$C_t^{Boilers} = \frac{1}{1000}\left[\frac{Q_t^{boiler}}{\eta_{boiler}} \cdot p_t^{gas} + \sum_{i\in Y} \frac{Q_t^i}{\eta_{biomas}} \cdot p_t^{biomass} - \sum_{i\in Y} Q_t^i \cdot p_{biomass}^{RHI}\right] \quad \forall t \in T \tag{8}$$

Where η_{boiler} and η_{biomas} are respectively the thermal efficiency of the gas boiler and the biomass units, Y the set of biomass units, $p_t^{biomass}$ the biomass price at time t, and $p_{biomass}^{RHI}$ the renewable heat incentive subsidy for biomass boilers units.

3.3. Carbon emissions

The actual carbon intensity of the scheme results from the imputation of the CO2e content of the natural gas, biomass and grid electricity consumed, discounting the carbon emissions related to the electricity produced by the CHPs and sold either to the grid or to the secondary electricity market. To calculate the carbon content of the electricity produced by the CHP, fuel apportion to heat and power is needed. The UK Department of Energy & Climate Change (DECC) recommends three possible methodologies for CHP fuel allocation: 1/3:2/3 Method, Boiler Displacement Method and Power Station Displacement Method [40].The first method assumes that twice as many units of fuel are required to generate each unit of electricity than those which are required to generate each unit of heat; the second one, that the heat generated by the CHP displaces heat generated by a boiler with an efficiency of 81%; and the third one, that the electricity generated by the CHP displaces electricity generated by conventional power only plant with an agreed efficiency (typically 47.7%) [40].

Deriving the equations presented by DECC [40], the electricity carbon factor – natural gas carbon factor ratio for the engine i and according to the DECC methodology j ($CF_{i,j}^{CHP\ elect/gas}$) can be expressed as:

$$CF_{i,1}^{CHP\ elect/gas} = \frac{2\cdot\left(\frac{Q_t^i}{S_i^{Max}} \cdot a_i + b_i \cdot y_t^i\right)}{2\cdot\left(\frac{Q_t^i}{S_i^{Max}} \cdot q_i + z_i \cdot y_t^i\right) + Q_t^i} \quad \forall i \in (\Psi\cup\Omega) \tag{9}$$

$$CF_{i,2}^{CHP\ elect/gas} = \frac{\left(\frac{Q_t^i}{S_i^{Max}} \cdot a_i + b_i \cdot y_t^i\right) - \frac{Q_t^i}{0.81}}{\left(\frac{Q_t^i}{S_i^{Max}} \cdot q_i + z_i \cdot y_t^i\right)} \quad \forall i \in (\Psi\cup\Omega) \tag{10}$$

$$CF_{i,3}^{CHP\ elect/gas} = \frac{1}{0.477} \quad \forall i \in (\Psi\cup\Omega) \tag{11}$$

With q_i and z_i the slope and the independent term of the linear power output function depending on the part load for unit i.

Excepting for methodology 3, the equations are not linear and, in consequence, cannot be implemented directly in the model. To solve this problem, step wise linearization can be used; however the dispersion of the ratios[4] not only for different part loads but also for different engines is relatively low (See Table 2). Hence, it seems fair to make the assumption of constant ratio ($CF_j^{CHP\ elect/gas}$) for each methodology. Thus, the carbon emission of the scheme at time t, according to the methodology j, ($CO2e_t^j$) is calculated as follows:

$$CO2e_t^j = \left(\frac{Q_t^{boiler}}{\eta_{boiler}} + \sum_{i\in(\Psi\cup\Omega)} \frac{Q_t^i}{S_i} \cdot a + b_i \cdot y_t^i\right) \cdot CF^{gas} + \left(\sum_{i\in\Upsilon} \frac{Q_t^i}{\eta_{biomass}}\right) \cdot CF^{biomass} + E_t^{grid\to DH} \cdot CF_t^{grid} - \left(E_t^{CHP\to grid} + E_t^{CHP\to Market2}\right) \cdot CF_j^{CHP\ elect/gas} \cdot CF^{gas} \quad \forall t \in T, \forall j \in \{1,2,3\} \tag{12}$$

With CF^{gas}, $CF^{biomass}$ and CF_t^{grid} the carbon factors of the natural gas, biomass and grid electricity at time t. Additionally, constraints in hourly ($\pi_j^{CO_2}$) and/or annual ($\Pi_j^{CO_2}$) carbon intensity can be set up:

$$CO2e_t^j \le \pi_j^{CO_2} \quad \forall t \in T, \forall j \in \{1,2,3\} \tag{13}$$

$$\sum_{t\in T} CO2e_t^j \le \Pi_j^{CO_2} \quad \forall j \in \{1,2,3\} \tag{14}$$

3.4. Technology size and existence

In addition to the general size constraints shown in Eq. (15) and to represent the discrete size behaviour of CHP and ORC technologies, Eq. (16) has been added. Accordingly, in case of existence, the size of these units is constrained to a discrete value, namely, the maximum size. Zero size if the technology is not selected, as Eq. (15) illustrates, applies to each of the technologies.

$$0 \le S_i \le S_i^{Max} \cdot X_i \quad \forall i \in \Theta \tag{15}$$

$$S_i \ge S_i^{Max} \cdot X_i \quad \forall i \in (\Psi \cup \Omega) \tag{16}$$

Since for biomass technology the investment costs entirely depend on the size of the unit and multiple units can be chosen as mentioned before, a minimum size (S_i^{Min}) constraint is added to avoid unrealistic solutions with a large number of biomass units of very small sizes:

$$S_i \ge S_i^{Min} \cdot X_i \quad \forall i \in \gamma \tag{17}$$

On the other hand, Eq. (18) has been included to preclude the existence of an ORC module unless its corresponding CHP engine exits. Eq. (19) has been also considered since certain ORC modules may not be available to be added (i.e. commonly ORC modules are not use in small size CHP engines):

$$X_i \le X_{i+n} \quad \forall i \in \Psi \tag{18}$$

$$X_i \le ORC_i \quad \forall i \in \Omega \tag{19}$$

With ORC_i a binary parameter equal to 1 if the ORC module i is available to be added to its corresponding CHP.

3.5. Heat energy production

Heat energy requirements must be satisfied any time and no heat can be produced in excess except for charging the thermal energy storage. Also, network losses have already been accounted in the heat demand so no extra heat is needed for this purpose. Apart from the heat produced by the technology mix selected, solar (Q_t^{Solar}) and other sources heat (Q_t^{Other}) may be available to help meet the demand. The final heat balance is shown in the following equation:

$$\sum_{i\in\Theta} Q_t^i + Q_t^{Solar} + Q_t^{Other} = D_t^{Heat} \quad \forall t \in T \tag{20}$$

Each of the units can supply heat in the period t provided they are active during this period of time. Naturally, only those units which actually exist can be active and, in addition, the heat that can be potentially produced is constrained by the capacity of the unit. No operation under the minimum part load of the technology (κ_i) is allowed. For all technologies except thermal storage (see next section for storage constraints formulation), these constraints are expressed as follows:

$$y_t^i \le X_i \quad \forall t \in T, \forall i \in \Theta - \{\text{TES}\} \tag{21}$$

$$Q_t^i \le M \cdot y_t^i \quad \forall t \in T, \forall i \in \Theta - \{\text{TES}\} \tag{22}$$

$$0 \le Q_t^i \le S_i \quad \forall t \in T, \forall i \in \Theta - \{\text{TES}\} \tag{23}$$

$$Q_t^i \ge S_i \cdot \kappa_i - M \cdot (1 - y_t^i) \quad \forall t \in T, \forall i \in \Theta - \{\text{TES}\} \tag{24}$$

With M an arbitrary large value.

Constraints in minimum running time between shut-downs (τ_i^{Min}) have been also included in the model and can be formulated as follows:

$$y_t^i \ge y_{t-1}^i - \frac{1}{\tau_i^{Min}} \sum_{p=\max\left(1,\ (t-\tau_i^{Min})\right)}^{t-1} y_p^i \quad \forall t \in (T - \{1\}), \forall i \in (\Theta - \{TES\}) \tag{25}$$

The preceding equation expresses the idea that a certain unit have to remain active during a period of time, t, if it was active in the time period immediately before, $t-1$, and provided it have not already been active in a row during a number of preceding periods of time equal or greater than the minimum running time between shut-downs (τ_i^{Min}) of the unit.

Subject to the corresponding ORC module existence, a CHP can be operated in two different modes, that is, with or without the ORC module, and, therefore, it can produce heat and electricity with different efficiencies for the same part load. Eq. (26) makes sure that the two possible CHP operating modes are not active at the same time. Finally, constraints in the operation of the CHP due to night noise council restrictions can be incorporated in the model as shown in Eq. (27):

[4] The scattering of the values (electricity carbon factor – natural gas carbon factor ratios, calculated for different part loads, Q_t^i, and different engines, S_i^{Max}, a_i, b_i, q_i and z_i) from the average.

$$y_t^i + y_t^{i+n} \leq 1 \quad \forall t \in T, \forall i \in \Psi \tag{26}$$

$$y_t^i \geq NR_t^i \quad \forall t \in T, \forall i \in (\Psi \cup \Omega) \tag{27}$$

With NR_t^i a binary parameter equal to 0 if the unit i cannot be operated at time period t due to noise restrictions.

3.6. Thermal energy storage

The sign of the variable related to the heat provided by the thermal storage, Q_t^{TES}, addresses the operating mode of the unit at time t: positive if the storage is being discharged, and negative otherwise. To track the stored energy level, accounting heat losses and avoiding overflow and negative levels, the following equations are proposed:

$$(-Q_t^{TES} + L_{t-1}) \cdot (1 - \zeta) = L_t \quad \forall t \in T \tag{28}$$

$$0 \leq L_t \leq S_{TES} \quad \forall t \in T \tag{29}$$

With L_t the heat level of the thermal energy storage at time t and ζ the rate of heat loss for thermal energy storage. Note that L_0 is the initial storage level (parameter).

Assuming insignificant radiation heat transfer and convention thermal resistance negligible in comparison with conduction resistance, the storage heat losses (q_t^{losses}) can be modelled using Fourier's law equation. Hence, considering a vertical cylindrical storage with a known height-diameter ratio (ε), whose heat exchange area (A_t^{losses}) function of the storage level is represented by Eq. (31), and taking into account Eq. (30), which links storage size in terms of heat storage capacity with volume (V), the heat loss rate can be expressed as function of the storage size and level as shown below:

$$S_{TES} = f \cdot V \cdot (T_s - T_r) \cdot \rho \cdot c_{e_{H_2O}} \tag{30}$$

$$A_t^{losses} = \left(\pi \cdot \left(\frac{4 \cdot V \cdot \varepsilon^2}{\pi} \right)^{2/3} \cdot \frac{L_t}{S_{TES}} + \frac{\pi}{4} \cdot \frac{\left(\frac{4 \cdot V \cdot \varepsilon^2}{\pi} \right)^{2/3}}{\varepsilon^2} \right) \quad \forall t \in T \tag{31}$$

$$\zeta = \frac{q_t^{losses} \cdot \Delta t}{L_t \cdot \frac{1}{f}} = \frac{\lambda \cdot A_t^{losses} \cdot \frac{(T_t^{TES} - T_t^{air})}{s} \cdot \Delta t}{L_t \cdot \frac{1}{f}} = f(S_{TES}, L_t) \quad \forall t \in T \tag{32}$$

With f a unit conversion factor ($kwh \rightarrow J$), T_s the district heating network supply temperature, T_r the district heating network return temperature, ρ the water density at the average temperature between T_s and T_r, $c_{e_{H_2O}}$ the water specific heat capacity, Δt a time increment equal to a model time period (3600s), λ the thermal conductivity of the thermal energy storage heat insulation, s the thermal energy storage heat insulation thickness, T_t^{TES} the thermal energy storage temperature at time t, and T_t^{air} the ambient temperature (external wall of the thermal energy storage) at time t. Considering typical heat insulation thickness values, the rate of heat loss is substantially low (less than 1%) even in worst scenarios in which small storages are operating at low level rates. Therefore and despite of the high nonlinearity of the expression, a constant rate of heat loss is assumed.

The amount of heat being diverted to the thermal storage or extracted from it is not only constrained by the size of the storage but also by its maximum power capacity (the storage may not be able to discharge all the heat accumulated, or be fully charged, in just one period of time because of physical constraints: pipes diameters, pumps capacity, etc.):

$$-S_{TES} \leq Q_t^{TES} \leq S_{TES} \quad \forall t \in T \tag{33}$$

$$-Q_{TES}^{Max} \leq Q_t^{TES} \leq Q_{TES}^{Max} \quad \forall t \in T \tag{34}$$

With Q_{TES}^{Max} the maximum heat power (charging and discharging) of the thermal energy storage. Nor minimum part load nor minimum running hours between shutdowns apply to thermal storage so, contrary to the rest of units, no equations related to the activity, or inactivity, of the thermal storage unit are needed.

3.7. Electricity energy balance

The electricity balance, describing production, imports, exports and internal, external and heat pump use, is written as follows:

$$E_t^{grid \rightarrow DH} + E_t^{CHP} = E_t^{HP} + D_t^{Elect,INT} + D_t^{Elect,EXT} + E_t^{CHP \rightarrow grid} + E_t^{CHP \rightarrow Market2} \quad \forall t \in T \tag{35}$$

With E_t^{CHP} the electricity generated by the CHP at time period t, E_t^{HP} the total electricity consumed by the heat pump at time t, and $D_t^{Elect,INT}$ the internal electricity demand for the scheme at time t.

As mentioned before, linearity between part load and power output has been evidenced for CHP with and without ORC modules (See table 8) and, consequently, the energy generated by the engines is computed as:

$$E_t^{CHP} = \sum_{i \in (\Psi \cup \Omega)} \left(\frac{Q_t^i}{S_i} \cdot q_i + z_i \cdot y_t^i \right) \quad \forall t \in T \tag{36}$$

The total electricity exported cannot exceed this energy generated by the CHP engines:

$$E_t^{CHP \rightarrow grid} + E_t^{CHP \rightarrow Market2} \leq E_t^{CHP} \quad \forall t \in T \tag{37}$$

On the other hand, the electricity consumed by the HP depends on the coefficient of performance (COP_t) as shown in Eq. (39). For this technology, the following simple energy balance is proposed, provided the constraints presented in Eq. (40) are satisfied:

$$E_t^{CHP \rightarrow HP} + E_t^{grid \rightarrow HP} = E_t^{HP} \quad \forall t \in T \tag{38}$$

$$E_t^{HP} = \frac{Q_t^{HP}}{COP_t} \quad \forall t \in T \tag{39}$$

$$E_t^{CHP \rightarrow HP} \leq E_t^{CHP}, \quad E_t^{grid \rightarrow DH} \geq E_t^{grid \rightarrow HP} \quad \forall t \in T \tag{40}$$

Where $E_t^{CHP \rightarrow HP}$ is the electricity generated by the CHP and consumed by the heat pump at time t, and $E_t^{grid \rightarrow HP}$ is the

Table 3
Slope, intercept and linear regression R-square values of the linear area function depending on size of each technology. To perform the linear regression, data from Bosh, Clarke Energy, DECC, Envinox, Siemens, MITSUBISHI, AERMEC, Treco, Herz, Core Biomass, AB&Co and Cochran [41], [43]–[54] has been considered.

Technology	$u_i\ [m^2/(kWth\ or\ kWh)]$	$v_i\ [m^2]$	$R^2{}_{area,i}$
Combined Heat and Power	0.0232	25.06	0.952
Organic Rankine Cycles modules	0.0058	6.26	0.952
Air Heat Pump	0.0501	20.90	0.971
Water Heat Pump	0.0146	6.40	0.889
Biomass Boilers (Pellets)	0.0248	22.22	0.891
Natural Gas Boilers	0.0200	7.61	0.821
Thermal Energy Storage	0.0089	40.10	0.981

electricity purchased from the grid and used by the heat pump at time t.

Finally, positive nature of electricity variables must be ensured any time and exports to the secondary market may be constrained:

$$E_t^{CHP\to HP}, E_t^{CHP\to grid}, E_t^{CHP\to Market2}, E_t^{grid\to HP} \geq 0 \qquad \forall t \in T \tag{41}$$

$$E_t^{CHP\to Market2} \leq \pi_t^{Market} \qquad \forall t \in T \tag{42}$$

With π_t^{Market} the maximum electricity exports to secondary market limit at time t.

3.8. Area requirements

Based on data sheets provided by numerous different HP, CHP, biomass boilers and gas boilers manufacturers [41], [43]–[54], it has been assumed that the footprint area taken by the units of these technologies (including not only the actual area taken by the unit but also the clearances) can be approximated as a linear function of the technology size. Assuming a vertical cylindrical configuration with a height three times the diameter and taking into account Eq. (30) to relate volume and storage size, the relation between footprint area and size can also be approximated as linear for the thermal storage. For ORC modules, it has been assumed that an additional 25% of the corresponding CHP area is needed in case of existence. Hence, the area required per each technology (A_i) can be calculated as follows:

$$A_i = \sum_{i\epsilon\Theta} S_i \cdot u_i + v_i \cdot X_i \qquad \forall i \in \Theta \tag{43}$$

Where u_i and v_i are the slope and the independent term of the linear area function depending on the size for unit i. The values of these parameters as well as the R values of the linear regressions are listed in Table 3. Being A^{Max} the maximum area available for building the DE center, constraints in area can be added:

$$\sum_{i\epsilon\Theta} A_i \leq A^{Max} \tag{44}$$

3.9. Implementation

The model is implemented in GAMS algebraic modelling [55] using the Cplex Mixed Integer Linear Programming optimiser [56].

4. Case studies and assumptions

The influence of different parameters into the optimal mix of technologies and the consequent optimal operation strategy, aim of this paper, is assessed by comparing the solutions of the reference case with the solution of a certain case studies, built from modifications on the reference case. The reference and the case studies proposed are described below:

4.1. Reference Case

The reference case considered in the study corresponds to the area scheduled to be covered by the both the extension and the current scheme of the Bunhill Energy Centre[5]. This area is located in the south of the London Borough of Islington [57], in Central London, UK. The optimization criteria is maximizing the total annual economic profit.

The complete hourly heat demand of the area under study has been provided by Bunhill Energy Centre to run the optimizations. However, due to confidentiality issues it cannot be supplied in this paper. The reader will be able to estimate the demand and to reproduce the results of the optimization using educated guesses and comparisons with similar schemes in available feasibility studies. In addition, the heat map[6] of the area under study (in black) is included in Fig. 2.

[5] Launched in November 2012, the Bunhill Energy Centre, located on Central Street, London Borough of Islington, London, UK, produces both electricity and heat, bringing energy to over 700 homes. The heat provision consists of large building level legacy boilers in the council properties and a 1MWth CHP providing the baseload (DHW) to the system. Additionally, as result of the London Borough of Islington district heating plan, an extension of the current scheme ('Bunhill 2') has already been scheduled in order to decrease heat supply costs for their council estate residents and to address the social problem of fuel poverty. The extension will result in a total annual heat demand of approximately 25,000MWh, covered mainly by a 1MWth air source heat pump that recovers waste heat from a London underground ventilation shaft and two 280kW CHP sized specifically to power the heat pump, which can also be powered by the grid [57].

[6] The heap map of the area of interest has been obtained from the National Heat Map, commissioned by the Department of Energy and Climate Change and created by The Centre for Sustainable Energy. The purpose of the Map is to support planning and deployment of local low-carbon energy projects in England by providing publicly accessible high-resolution web-based maps of heat demand by area.

In this reference case study, it is assumed that there is no electricity users connected to the energy district network and, therefore, the external electricity requirements or demand is inexistent. Concerning the internal electricity requirements, it has been assumed that they are independent of the technological mix selected, since these energy requirements are mainly motivated by the power consumption of the water pumps to feed the district network. As it happens with the heat demand, the internal electricity heat demand used in the optimization is provided by Bunhill under confidentiality agreements.

In order to calculate the import and export grid electricity prices, the electricity pricing models presented by Acha and co-workers [58] have been used. These pricing models are based on the sum of a number of components including the wholesale price, transmission (TNUoS[7]) and Distribution Costs (DuOS[8]) [59], [60]. According them, the Triads[9] charges are distributed among the winter afternoon periods taking into account the probably of occurrence. Positive distributions cost are considered for electricity imports and negative ones for electricity exports to de grid. Unlike Acha and al. presentation, wholesale prices are not averaged into day types in this study and commercial specific component of the model are not included here. Practically, the wholesale prices considered have been obtained from Nord Pool [61].

The heat prices per type of costumer, shown in Table 4, have been obtained from the Redbridge Decentralized Energy Masterplan report [62] written by Ramboll Energy. According to the London Borough of Islington Council data, it has been assumed that the 90% of the generated heat is consumed by community users and the rest 10% by commercial users.

The London natural gas prices considered, contribution from The Queen Elizabeth Olympic Park Energy Centers[10], cannot be displayed according to the non-disclosure agreement.

The hourly electricity UK grid carbon factors are calculated as the weighted average of the UK carbon factors by electricity source (See Table 5) presented by Rogers and Co-workers [64]. The electricity production data disaggregated by electricity source to calculate the weighted averages is courtesy of BM Reports [65], [66], property of ELEXON [67].

In the case of the heat and power demands and the electricity tariffs given make the CHP technology taking part in the optimal set of technologies, most likely the yearly baseload heat requirements would be covered by a medium or large size CHP (according to size of the set of available CHP units presented in Tables 7 and 8). However, trade-offs appears with respect to the selection of the rest of CHP units, e.g. purchase of a single unit, which benefits from economies of scale but generates electricity

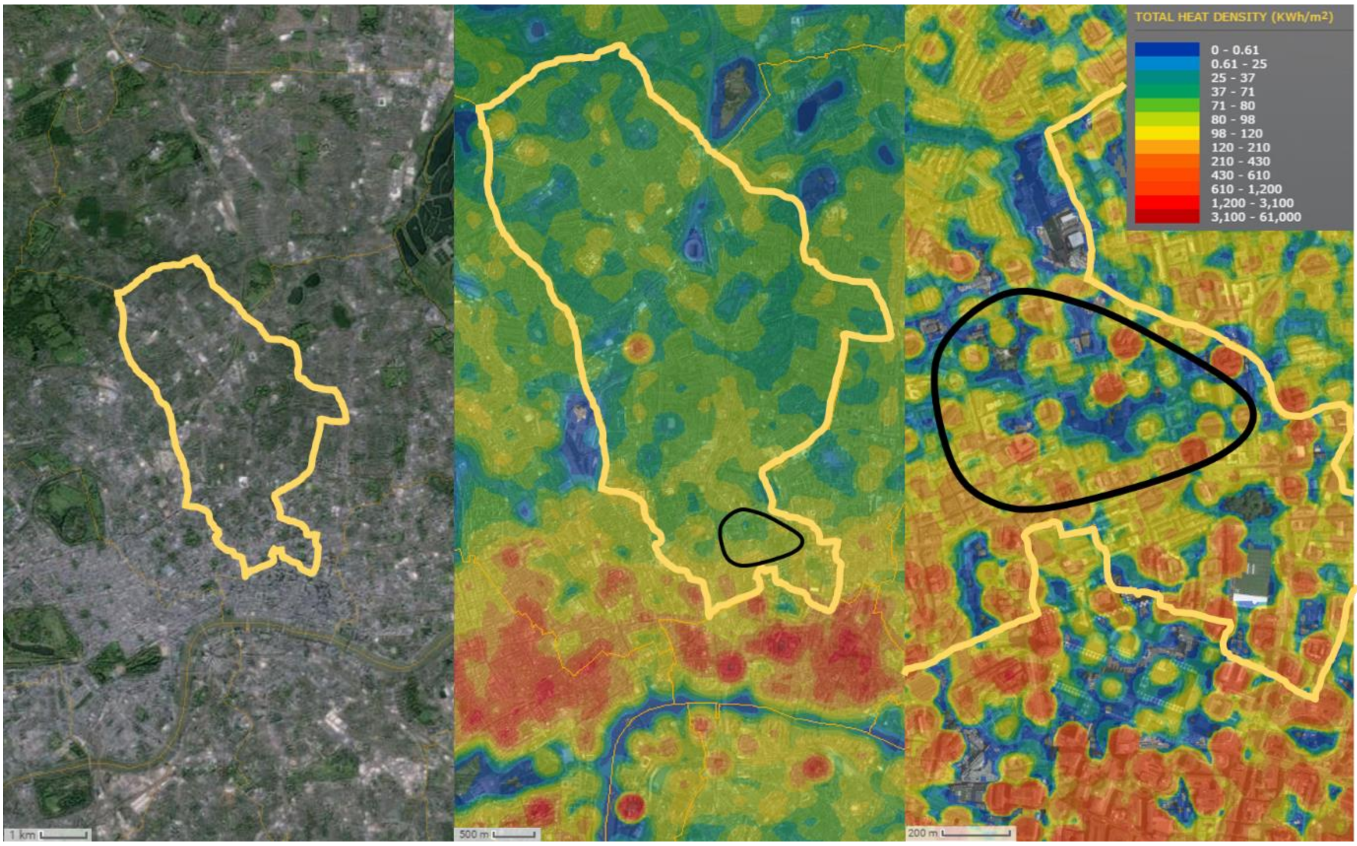

Fig. 2. From left to right: Satellite image of the London Borough of Islington (area in yellow), central London; heap map of the London Borough of Islington including the location of the area under study (in black); and enlarged heat map, focused on the area under study.

[7] The TNUoS charges relate to National Grid's transmission charges and are the basis for recouping the cost of maintenance and investment in the electricity grid. The three Triad periods are used to set these charges.

[8] The distribution charges, known as the "distribution use of system" (DUoS) charges, are paid to the distribution network operator (DNO) on whose network the meter point is located. The charges are: availability or supply capacity, reactive power and a fixed charge.

[9] The Triads are the three half-hour settlement periods with highest system demand and are used by National Grid to determine charges for demand customers with half-hour metering and payments to license exempt distributed generation.

[10] The Queen Elizabeth Olympic Park is powered by two cutting edge energy centers, each of them designed, financed and built by Cofely, the energy services company of GDF SUEZ, along with approximately 18km of insulated heat and cooling networks as part of a 40-year energy concession on the Park. Each center has an initial capacity of 46.5 MW of heating and 16 MW of cooling [63].

only in winter or several smaller units some of which could keep running during summer peaks [4]. For this reason, a wide range of CHP unit sizes has being considered into the model superset, being the greatest CHP units is replicated more times than the smallest ones. In total, 80 CHP units has been considered not to compromise too much the optimization runtime. In this superset, three possible biomass boilers (continuous size) has been also included. For the reference case, it has been assumed that the ORC modules technology is not available.

Table 4
Heat prices per type of costumer [62].

Costumer Type	Proportion [%]	Heat price [$£/MWh$]
Community User	90	38.5
Commercial User	10	40.9
NHS	0	35.8
Other Public	0	38.5
Other	0	38.5

Table 5
UK carbon factors by electricity source [64].

Symbol	Fuel Type	Carbon Intensity (gCO2/kWh)
CCGT	Closed cycle gas turbine	360
OCGT	Open cycle gas turbine	480
COAL	Coal	910
NUCLEAR	Nuclear	0
WIND	Wind	0
PS	Pumped storage	0
NPSHYD	Non-pumped storage hydro	0
OTHER	Other	300
OIL	Oil	610
INTFR	French Interconnector	90
INTIRL	Irish Interconnector	450
INTNED	Dutch Interconnector	550
INTEW	East-West Interconnector	450

Air sources heat pumps able to recover waste heat from a nearby London underground ventilation shaft have been assumed as heat pump available technology. While the heat pump source temperatures (London Underground) have been provided by the Bunhill Energy Centre, it is has been assumed an 80°C constant nominal heating network supply temperature as the sink temperature. The hourly coefficient of performance of the heat pumps have been calculated using the ammonia refrigerant table 9, retrieved from DECC [42]. Tables 11 and 10 are presented in case other sink temperature is selected.

The rest of the assumptions made to run the ECS model in the reference case, are shown below:

- The cooling requirements have been neglected[11].
- There is no heat available from other sources and, therefore, the demand has to be entirely met with heat produced by the energy centre.
- It has been considered that there is no possibility to sell produced electricity to a secondary electricity market.
- The heating network return temperature is assumed to be 60°C.
- The distribution network losses have already been accounted into the heat demand.
- The thermal energy storage rate of heat loss is calculated assuming the worst scenario in which a small storage is selected into the optimal mix. In concrete, the heat storage capacity of 1000kWh has been considered and the rate calculated considering the average of the losses of the operation in levels from 0 to 100%.
- Initially, the thermal energy storage is empty.
- Excluding the TES, a maximum size such the 110% of the maximum heat demand peak could be covered by the unit has been assumed for continuous size units. The value of 30,000 kWh has been stablished as the maximum thermal energy storage capacity, being 12MW the maximum charging and discharging heat power of the TES.
- The minimum biomass boiler unit capacity has been set up in 100kWth.
- Biomass boilers and natural gas boilers thermal efficiency is assumed to be 85% and 90% respectively [1].
- No night noise council restrictions have been assumed as well as no available area or carbon emissions constrains.
- Pellets fuel has been assumed for biomass boilers. The price of the pellets is supposed to be constant throughout the year and equal to 31 £/MWh [42].
- The government renewable heat incentive subsidy is 20.6 £/MWh for biomass boiler units and 25.4 $£/MWh$ for heat pumps, according to the available data from different London energy centres [57], [63].
- It is assumed and all the technology cost factors and parameters are up to date. In consequence, the Reference Marshall & Swift factor is the factor of the current year (2016).
- Taking into account the risk factor, the interest rate selected is 7%[12] [68].
- Since the minimum part load of CHP units, with and without ORC, considered is 70% (See Table 1), the average values of the ratio electricity carbon factor - natural gas carbon factor corresponding to the operation at part loads between 75% and 100% have been used to calculate the carbon content of the electricity produced by the CHP.
- The natural gas carbon factor is 0.18639 $KgCO_2e/kWh$ and the biomass (pellets) carbon factor is 0.0130 $KgCO_2e/kWh$. Both values have been retrieved from DECC [69].

4.2. Case Studies

Unless otherwise explicitly indicated, all the assumptions made in the reference case also apply to the case studies. The case

[11] Cooling demand is usually generated by shopping malls, hospitals, sport facilities, theatres, museums, auditoriums and public buildings. Thus, according to the distribution of types of costumers connected to the district network, shown in Table 4, a null or insignificant cooling demand is likely to arise in the area under study and can be converted into electricity requirements assuming a seasonal efficiency ratio of 3.5 [1].

[12] Other values that may be considered: 7-8% for private scheme, 4-5% for public-private partnership and 2% for public scheme.

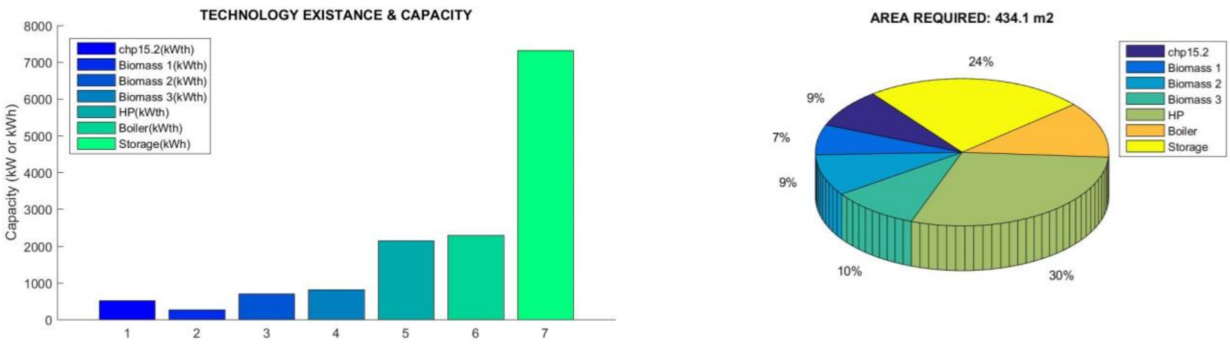

Fig. 3. Reference Case. From left to right: Technology existence and capacity; and total area and percentage of the total area taken by each existent unit.

studies together with the parameters whose impact in the energy centre design is intended to be studied are presented below:

4.2.1. Electricity market, prices and external demand

Two case studies in which both the reference case import and export prices are raised, and decreased, by 25% are taken into account to explore the influence of the grid electricity prices in the solution. Additionally, the impact of the existence of a secondary market is studied though a case studies assuming a secondary market fixed price equal to 67£/kWh, a value in between the average import grid electricity price and the average export one. Finally, the existence of an external demand[13] is considered in another case study.

4.2.2. Gas price

Two scenarios in which the natural gas is a 25% cheaper and more expensive have been considered.

4.2.3. Carbon emissions

Optimization criteria are switched to minimum annual carbon emissions and a carbon driven strategy case study is proposed per DECC displacement methodology. Thus, not only differences between economic and environmental approaches can be spotted but also the differences between the three CHP fuel allocation methods. Additionally, several case studies in which different percentages of emission savings compared to the reference case are considered to evaluate the relation between annual emissions and profit and the different technology mix resulting.

4.2.4. Area

A minimum area optimization criteria as well as several case studies with different percentages of area savings compared to the reference case are explored in order to track the evolution of the technology mix towards the minimum area solution and assess the impact of space constraints into the yearly profit.

4.2.5. Heat sources

The availability of heat from other extra sources different from the technology mix and, oppositely, the non-availability of a heat production technology is also studied. In concrete, the following cases studies are proposed:

[13] The external demand has been generated using the Agent-based model proposed by Bustos-Turu et al. [71], [72]

- Solar heat available. The solar heat profile is estimated using the approach shown in the heat pumps in district heating model v62 proposed by DECC [42].
- ORC modules available.
- CHP night noise restrictions, from 10pm to 7am [57], apply.
- CHP technology not available.
- HP technology not available.
- Biomass boiler technology, natural gas boilers technology, and both of them, not available.

4.2.6. Renewable heat incentive subsidy

By rising up, decreasing and suppressing the RHI biomass and HP subsidies the economic viability of the most environmental friendly technologies of the set is intended to be studied.

Changes in heat prices or costumers distribution will not affect the optimal mix and therefore are not considered.

5. Results

5.1. Reference Case

The results of the reference case optimization are shown in Figs. 3, 4, 5 and 6 as well as Table 6. According to Fig 3, each of the available technologies takes part into the optimal mix. Thus, the energy centre is composed by a medium size CHP engine (442kWth), a relatively large HP (2115kWth), three biomass boilers (Total power: 1770kWth), a modest natural gas boiler (2288kWth) and a medium-small size storage (7326kWh). The resulting annual profit is near 0.5 M£, being the required area 434m^2.

In winter, as Fig. 6 shows, the CHP, the HP and the biomass boilers are run during almost the whole day, providing the heat baseload. At around 6pm (peak demand), the export and the import price of the electricity are quite high and, in consequence, it is really profitable to stop running the HP, which requires (expensive) grid electricity imports, and export the energy produced by the CHP to the grid. Oppositely, at 1am, when the TES is almost full, the export and the import price of the electricity are the cheapest and, therefore, it is cost-effective to prioritize the use of HP versus biomass boilers. The heat demand is balance by charging the thermal energy storage during night hours and discharging it in the peak hours. The natural gas boiler is used to top up the demand whenever the rest of the units are not enough to meet the heat requirements or when the HP is turned off. The CHP unit is not able to satisfy the electricity demand itself so

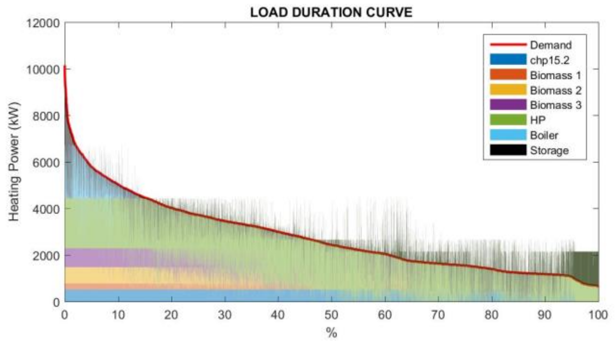

Fig. 4. Reference Case. Load Duration Curve. The area above the demand represents the heat produced for storage purposes.

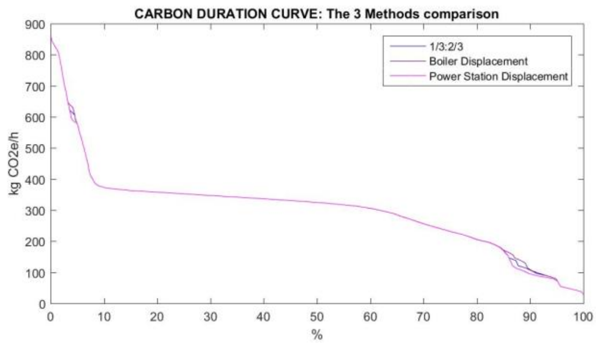

Fig. 5. Reference Case. Carbon duration curve considering the 3 methodologies presented by DECC [40].

electricity imports are required. By consuming stored heat, the used of the HP is avoided in these period for which the grid electricity prices are quite high.

The HP in combination with the TES is used to satisfy the heat demand in summer. Thus, during the night, when the electricity is cheaper, the HP produces heat in excess to charge the storage. This stored heat is used in these period for which the grid electricity prices are quite high. In this season, all the electricity required is imported from the grid.

The annual load duration curve (Fig. 4) demonstrates that the HP provides the baseload of the annual heat demand and the TES cuts the peak demand. The CHP unit is also active the most part of the year and the natural gas boiler is the least used, only run in winter, when the heat demand is really high.

Regarding carbon emissions, approximately 2600 tonnes of equivalent carbon dioxide are emitted per year. The high carbon intensity periods correspond to the winter day hours and the low ones, to winter nights or summer periods. The differences among the carbon duration curves of each of the three methods arise from the exports of produced electricity to the grid. Since different percentages of fuel are allocated to the CHP electricity production depending on the method, different carbon factors for the export electricity are obtained. The power station

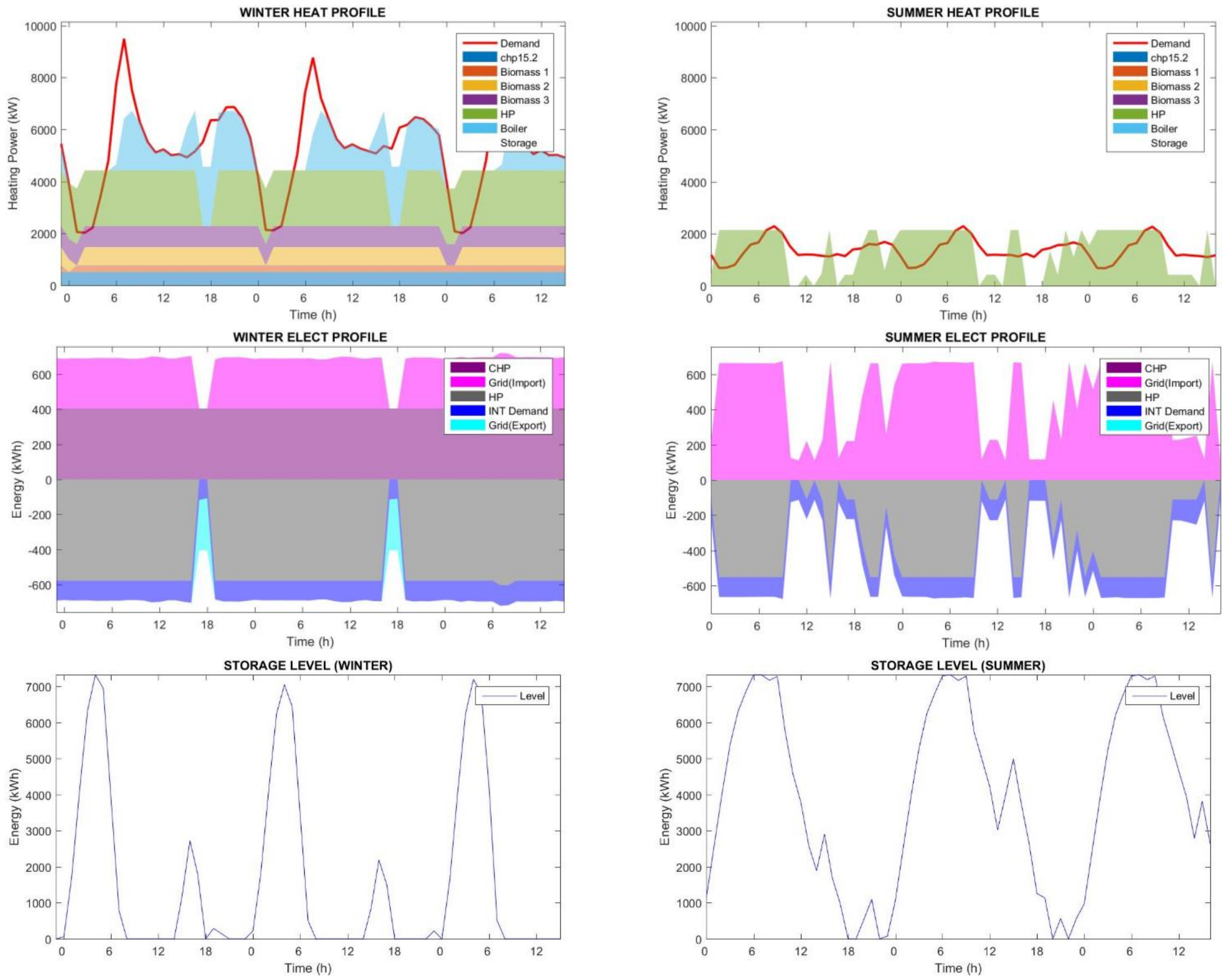

Fig. 6. Reference case. Winter (left) and summer (right) heat profiles (up), electricity profiles (middle) and storage level (down). Concerning the heat profiles, note that the area above the demand (red curve) represents the heat produced for storage purposes and the white area below the demand, the heat provided by TES.

displacement method reports the best results by assigning the highest carbon content to the produced electricity. Thereby, when the produced electricity is sold, the scheme deducts more carbon emissions and therefore the annual carbon emissions result is lower.

5.2. Electricity market, prices and external demand

In case that the grid electricity price decreases a 25%, the optimal solution remains nearly the same as the reference case one. In the optimal technology mix, the biomass power is reduced to 966kWth in favour of a one more CHP unit number 15, as figure 7 shows. The winter heat production profile is essentially the same: baseload heat provided by the CHPs and the biomass units; the HP stopped in the afternoon, when the electricity is the most expensive, to export more energy to the grid; and natural gas boiler used to top up. However, in winter no grid electricity is needed since the two CHP combined are not only able to satisfy the electricity demand but also to produce some energy in excess to export to the grid. The heat and electricity production profiles for winter do not change at all. The decrease in income per kWh of electricity exported is compensated by exporting more energy (2 CHPs) and by the reduction in the costs associated with the electricity imports to run the HP. Hence, the annual profit is approximately the same. The carbon emissions, as result of the similar modus operandi, and the area required, consequence of the similar technology mix, are also equivalent.

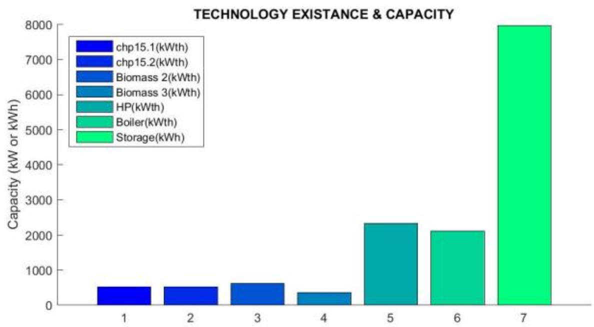

Fig. 7. Case study: grid electricity price 25% reduced. Technology existence and capacity.

Nevertheless, the optimal technology mix completely changes if grid electricity price is raised a 25%: three CHP engines number 22, the biggest ones, and a big storage (23500kwh) are selected (see Fig. 8).

On the one hand, during winter, the CHP are run along the whole day only stopping some hours in the night, when the

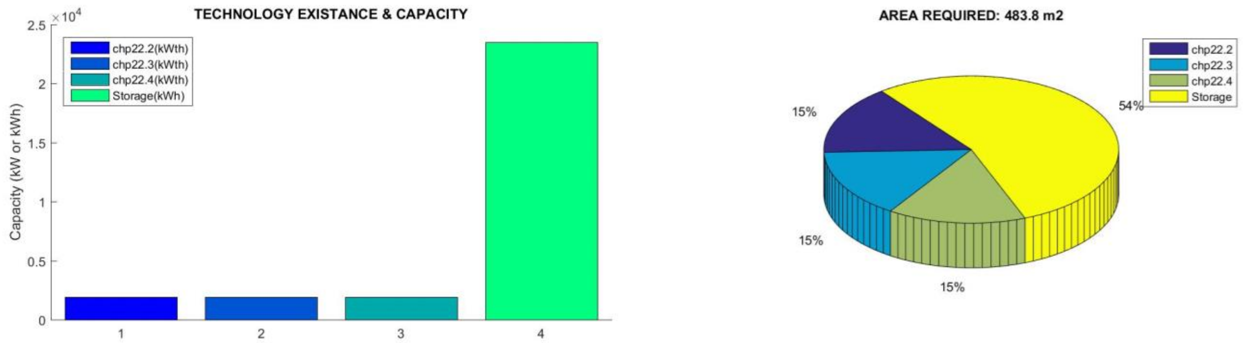

Fig. 8. Case study: grid electricity price 25% augmented. From left to right: Technology existence and capacity; and total area and percentage of the total area taken by each existent unit.

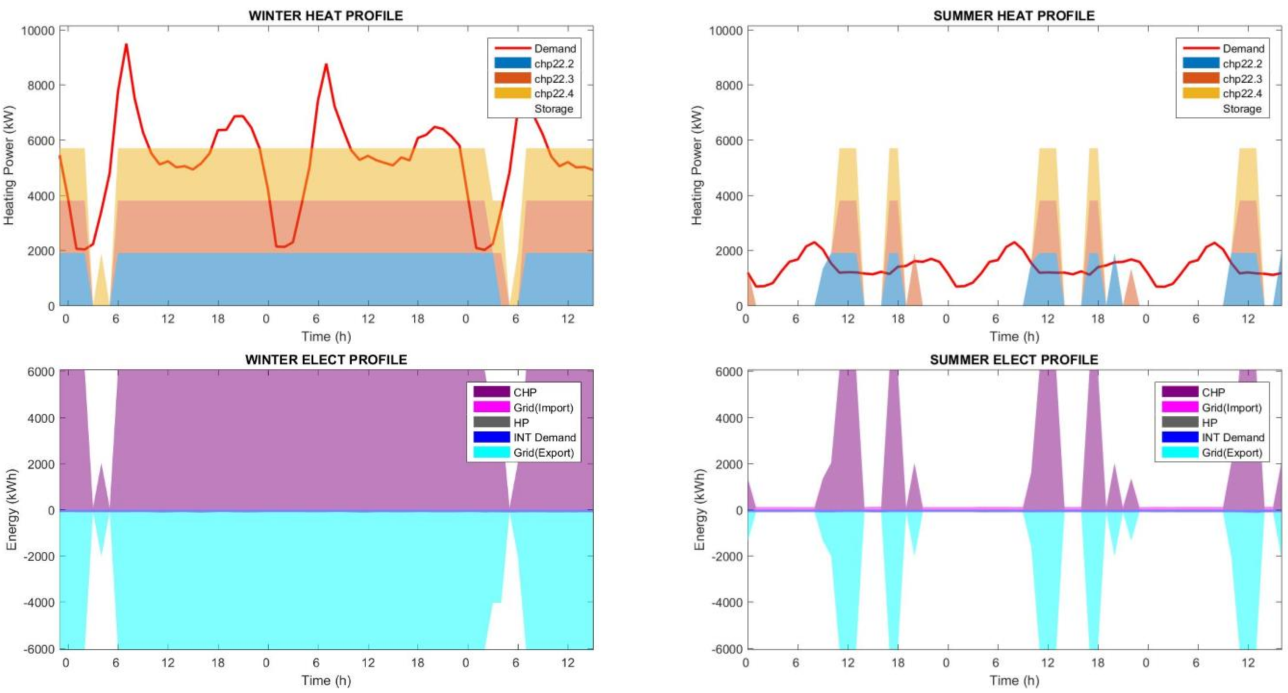

Fig. 9. Case study: grid electricity price 25% augmented. Winter (left) and summer (right) heat profiles (up) and electricity production profiles (down).

electricity is the cheapest and therefore incomes from exporting the lowest, not to overcharge the storage. The TES allows cutting the peaks from approximately 10MW to 6MW. On the other hand, in summer (lower heat demand), thanks to the high capacity of the TES, the CHPs are only run a few hours a day, when the electricity price is high and it can be made the best of the exports, and the rest of the time the demand is met by heat previously stored in the TES. Grid imports are only needed when the CHP engines are turned off and are negligible in comparison with the exports. The incomes from selling electricity at 25% higher price not only compensate the investment cost of the three CHPs but also make the annual profit increase a 45% (See Table 6).

Owing to the extensive electricity exports, the difference among the three carbon methods is highly emphasized: the annual carbon emissions reported using the 1/3:2/3 displacement are three times the emissions reported using the power station displacement, as Table 6 and Fig. 10 show.

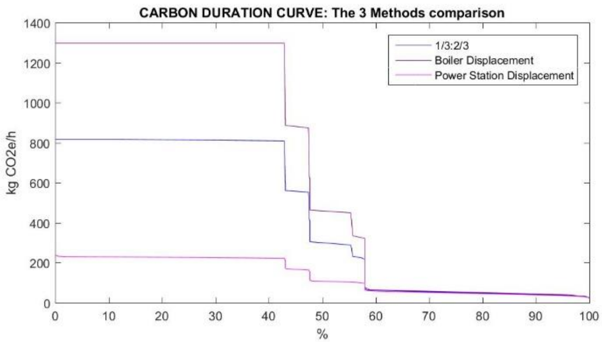

Fig. 10. Case study: grid electricity price 25% augmented. Carbon duration curve considering the 3 methodologies presented by DECC [40].

In case of external electricity demand existence, while the HP and the natural gas boiler are slightly smaller in comparison with the reference case solution, the TES capacity is a little bit greater. Additionally, the biomass power is reduced to 544kWth and three more medium-size CHP units are included into the optimal set (See Table 6). The winter heat production profile follows the same principles than the reference case and the summer one, in order to reduce costs, is modified to include some CHP running hours in those periods in which the grid electricity is the most expensive and the external electricity demand, high. Regarding the electricity profiles, the CHP engines are not enough to cover the electricity demand peaks so grid imports are needed both in winter and summer. The business of selling electricity to private users is such profitable that the total annual profit increases in a 50%. The annual carbon emission are also greater due to the displacement of the biomass boilers by CHP technology. However, the discrepancy among the three methods is smaller than in the previous case study since the electricity exports are not that extensive.

The existence of a secondary market to which electricity can be exported at a fixed price considerably modifies the optimal mix. As table 6 shows, there is no HP anymore, biomass technology is reduced almost to the minimum, natural gas boiler capacity nearly halved, TES slightly increased and four CHP, 2 medium size and 2 large size, included. The winter heat production profile is quite similar to the case study in which the grid electricity prise is augmented (Fig. 9) but including boilers, which are used to top up the peak demand (biomass boilers are preferred). In summer, the heat requirements are covered by running CHP mainly during the day, when the grid electricity price may be higher that the secondary market price, and by using stored heat during the night. The grid market is preferred for weekday exports between 11am and 1pm (higher selling price) and in winter also for weekday exports at around 6pm when a Triad is most likely to occur. The introduction of a secondary market makes the energy centre a 55% more profitable. Electricity exports either to the grid or to the secondary market are quite extensive. Hence, the annual carbon emissions result strongly differs from one method to the other and the carbon duration curve is approximately the same as the one shown in Fig. 10.

5.3. Gas price

The 25% gas price increase is reflected in a displacement of natural gas boilers by biomass boilers. Thus, the optimal mix

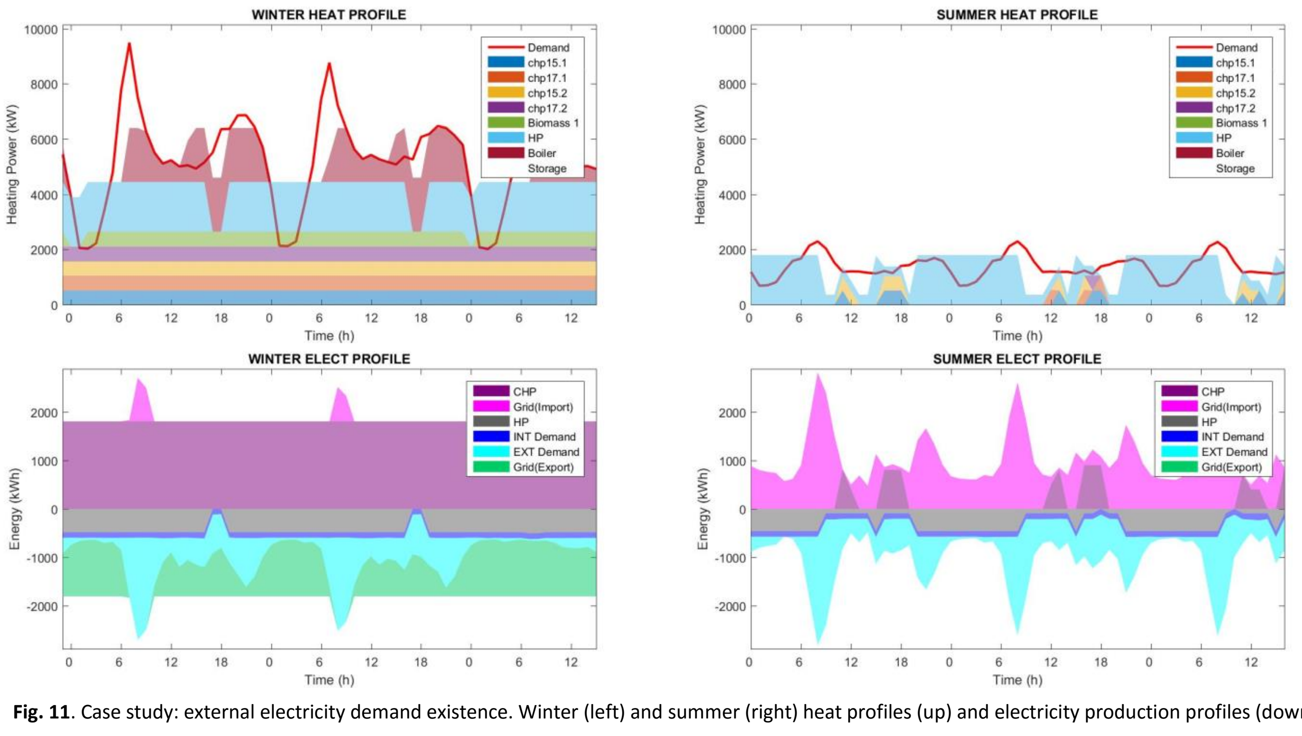

Fig. 11. Case study: external electricity demand existence. Winter (left) and summer (right) heat profiles (up) and electricity production profiles (down).

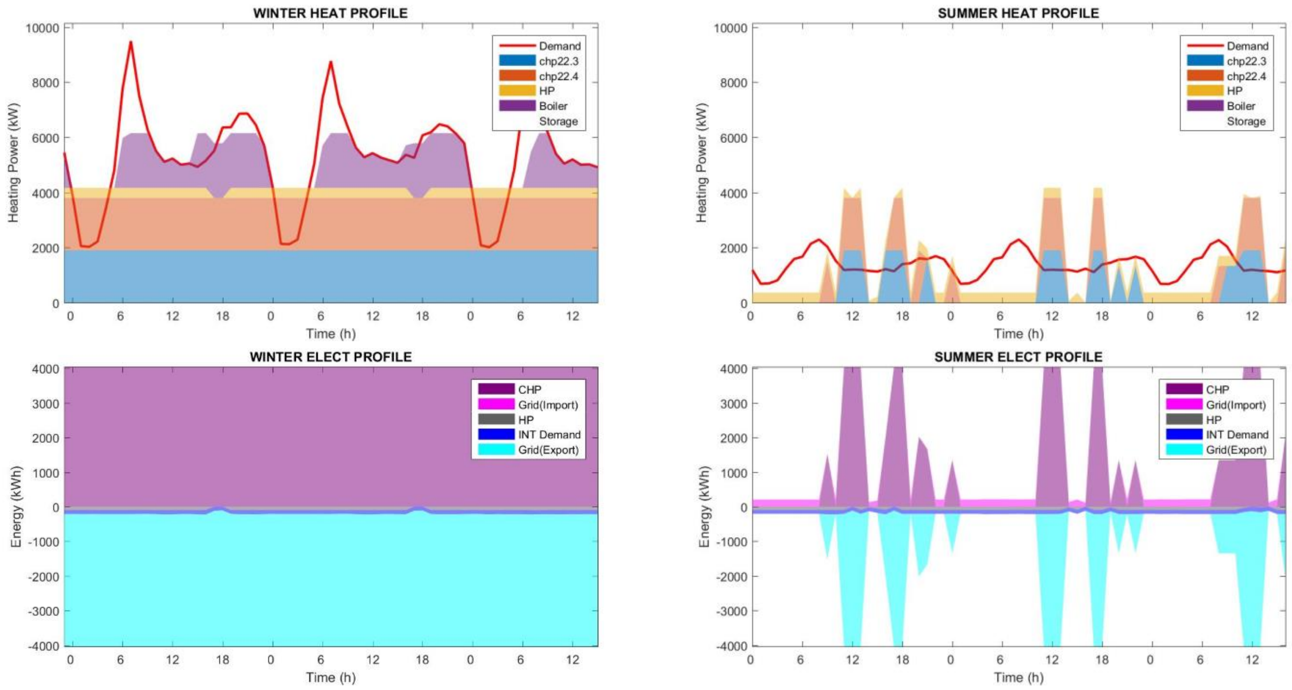

Fig. 12. Case study: natural gas price 25% augmented. Winter (left) and summer (right) heat profiles (up) and electricity production profiles (down).

resulting is equal to the reference case but with a 1000kWth of natural gas boilers power less in favour of the biomass boilers. The energy profiles, total required area, economic result and carbon emissions are almost identical to the reference case ones (See Table 6 and Figs. 4, 5 and 6).

However, a 25% decrease in the gas price has a greater impact in the solution. The use of the CHP is even more profitable and natural boilers are preferred instead of biomass boilers despite the renewable heat incentive subsidy. In consequence, the optimal mix consist of two large size CHP, a small HP, a medium-small size natural gas boiler and a medium size storage to balance the heat production in summer (See Table 6). As usual, in winter the baseload heat is provided by the CHPs and the HP, which only stops three hours in the afternoon in the weekdays when the grid export price signal is very high. The NG boiler is used to top up the demand peaks and the storage to balance the demand. In summer, the CHPs are run mainly during the hours when the export electricity price is higher, producing heat in excess to charge the storage. The rest of the day the demand is meet by the HP and the stored heat. Again, as result of running large CHPs during many hours, electricity exports are extensive and consequently the appearance of the carbon duration curve is similar to this shown in Fig. 10.

5.4. Carbon emissions

Switching from a purely economic to a carbon driven strategy states that annual carbon emissions can be reduced up to a 70% in comparison to the reference case optimization. The three

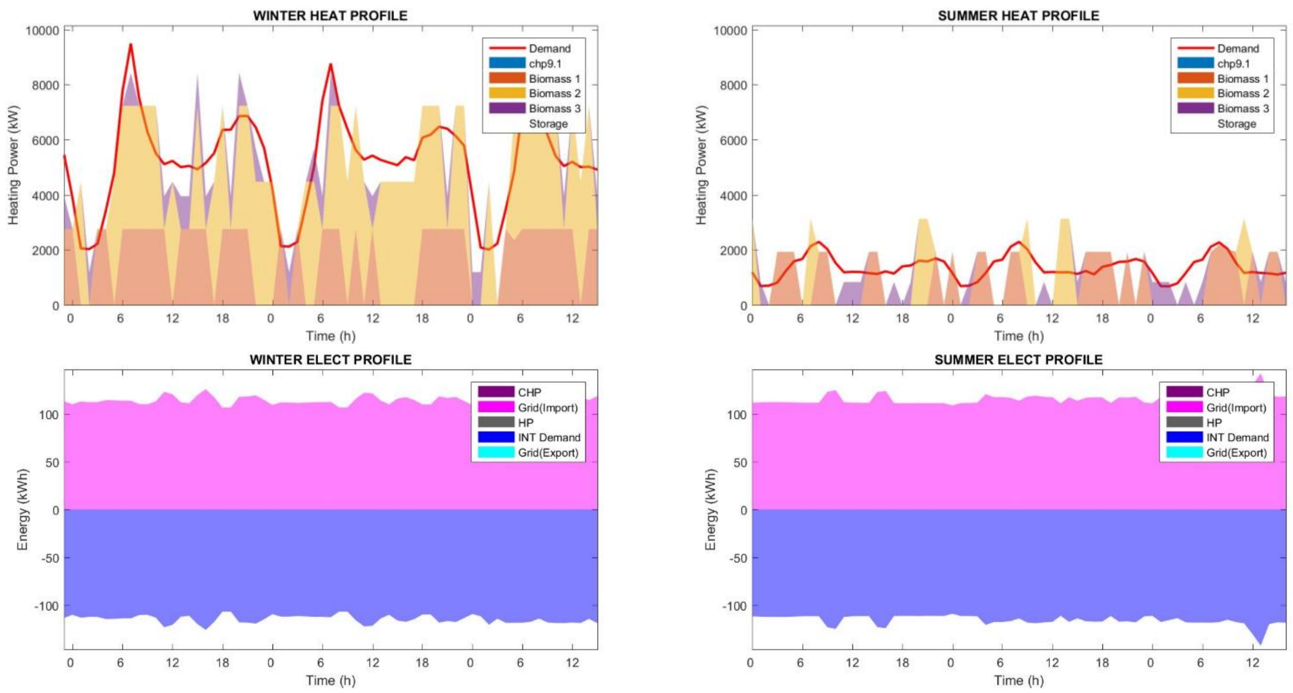

Fig. 13. Case study: Carbon driven strategy, 1/3:2/3 Methodology. Winter (left) and summer (right) heat profiles (up) and electricity production profiles (down).

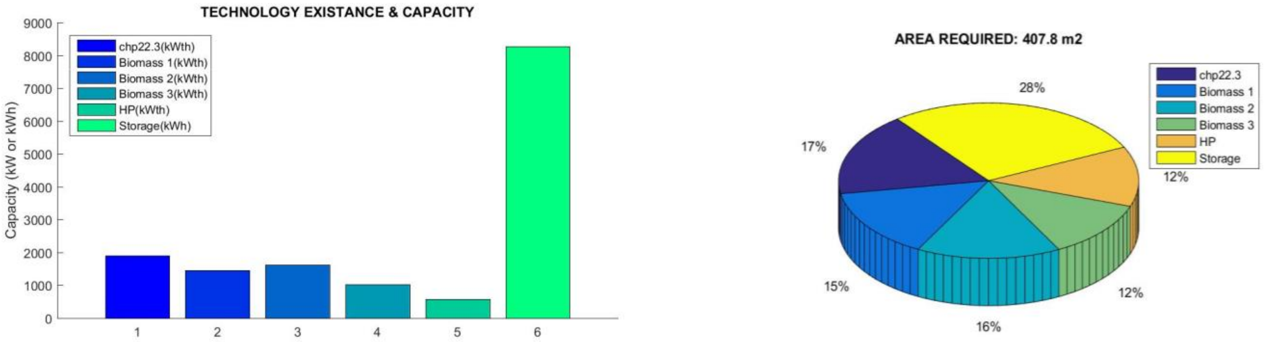

Fig. 14. Case study: 50%savings in carbon emissions according to power station methodology. From left to right: Technology existence and capacity; and total area and percentage of the total area taken by each existent unit.

carbon driven optimizations, once per DECC displacement methodology, report a very similar optimal technology mix: biomass boilers as the core of the heat production (heat power between 8.4 and 9.5MW), a small CHP and the maximum size thermal heat storage (30.000kWh). The boiler displacement methodology case study also includes a small HP (See Table 6). Note that even though a boiler displacement carbon driven strategy is followed, worse results in annual carbon emissions according to this methodology are obtained than in the other two optimizations. This is caused by the solver tolerance stopping criteria [56]).

Regarding the heat profiles, both in winter and in summer the heat tends to be produced by the biomass boilers (the technology with the lowest carbon factors, at the time it is needed), being the function of the storage to avoid the mismatch between production and consumption caused by the minimum part load constraint. The CHP, whose capacity is the minimum needed to produce enough electricity to potentially meet the internal electricity demand, is used in a few winter periods when the grid electricity carbon factors are high to avoid vastly carbon content electricity imports. Except in these periods, electricity is imported from the grid to satisfy the internal electricity demand. The energy profiles of the 1/3:2/3 displacement method case study are shown in Fig. 13. The boiler and power station displacement method profiles are omitted for being almost identical.

Since a purely carbon driven strategy is followed, the solution is economically unprofitable: more than 5M£ are lost per year. However, balance between environmental sustainability and profitability can be attempted by following an annual profit driven strategy with annual carbon emissions constraints. Thus, considering a 50% saving in emissions (according to power station displacement method), it is demonstrated that the annual profit is only reduced in a 15% (See Table 6). The optimal technology mix and the profiles of this case study are shown in Figs. 14 and 13.

In winter, the CHP and the HP are used to meet the baseload heat, the TES to cut the peaks and the biomass boilers to top up the demand. Large amounts of electricity are exported to the grid and no imports are needed. In summer, while the HP continue being run the whole day, the CHP is run only during the electricity red periods, when the electricity can be sold at the highest price. The biomass boilers are used to top up the demand when the

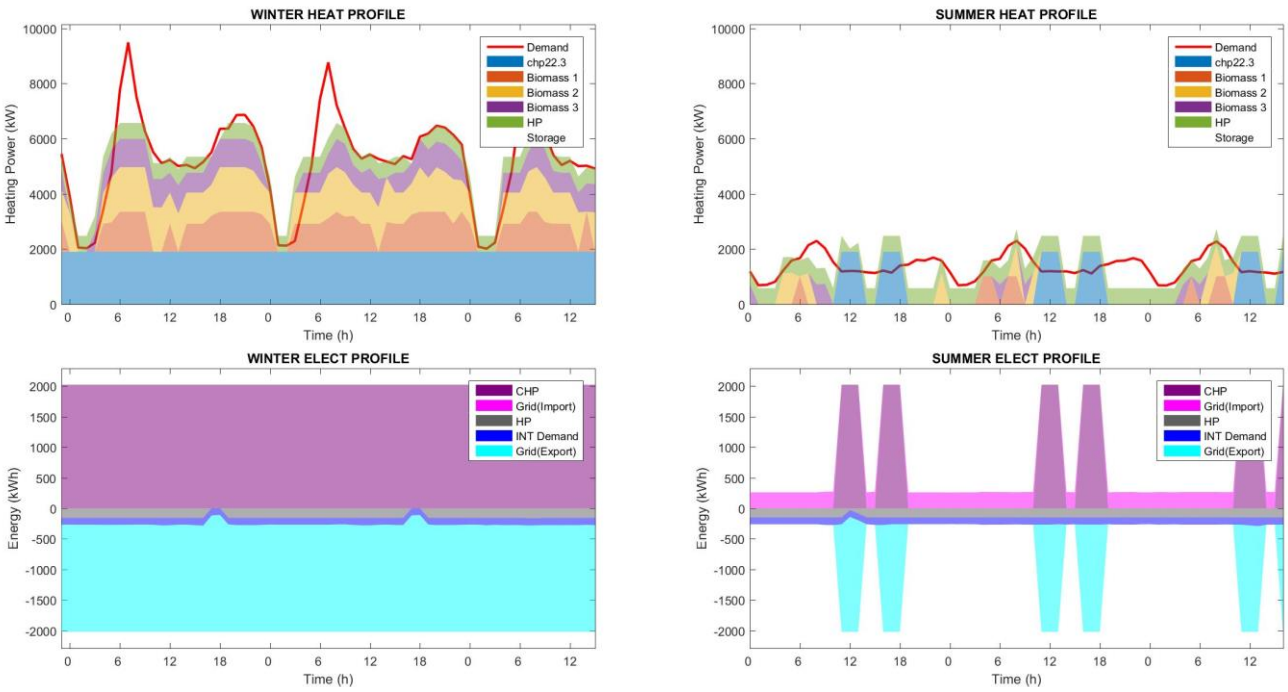

Fig. 15. Case study: 50%savings in carbon emissions according to power station methodology. Winter (left) and summer (right) heat profiles (up) and electricity production profiles (down).

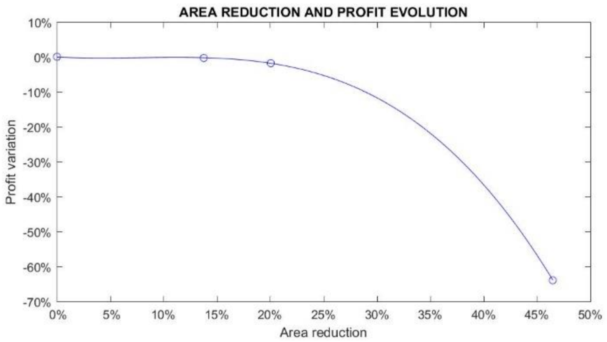

Fig. 16. Profit evolution as function of area reduction, following a maximum annual profit driven strategy.

combination of HP and stored heat is not enough. Grid electricity is imported when the CHP are not working.

Contrary to the purely carbon driven optimization case studies, in this case the carbon emission results highly vary depending on the methodology (motivated by the electricity exports) and, therefore, the optimal mix also vary a lot depending on which methodology is used to calculate the constraint in carbon emissions.

5.5. Area

A combination of a large gas boiler and a small TES result to be the optimal solution according to the minimum required area strategy (See Table 6). The operation is simple: the storage cuts the demand peaks so less boiler power is need and the electricity demand is met by grid imports.

Fig. 17 summarize the evolution of the technology mix towards the minimum required area, optimizing the annual profit. Firstly, biomass and HP technology tends to be reduced in favor of NG boiler and CHP technology, being biomass the first technology in disappear. After that, NG boilers dominates and completely displaces the remaining CHP technology. The storage capacity slightly decreases along the area reduction. Regarding the impact of the area reduction into the annual profit, Fig. 16 proves that whereas reductions up to a 20% have a small influence in the annual profit, large area reductions compromise the annual economic result.

5.6. Heat sources

While the effect of the availability of solar heat in the solution is negligible (See Table 6). Energy profiles are almost identical to the reference case ones), the possibility of adding ORC modules to the CHP engines multiply by 3.5 times the annual profit and completely changes the solution: The technology mix resulting is composed by three units of the largest CHP engine with ORC modules, a small boiler (772kWth) and a medium TES (17559kWh). In winter, the three CHP units are running with the ORC module active during the whole day, being the boiler used to top up and the storage to balance the demand as usual. In summer, the heat demand is much lower hence only some running hours of CHP per day are needed to meet the energy requirements. To optimize the incomes, the hours when the electricity price signal is highest (red periods) are selected (See Fig. 20). Concerning the electricity profiles, the ORC modules improve the electricity production efficiency. This, linked to the prevalent use of three large CHP, makes the electricity exports to be highly extensive. In consequence, not only the difference between the three DECC displacement methodology is spotted but also the exports are such that the annual carbon emissions result, according to the power displacement methodology, is negative (See Fig. 21).

The potential night noise council restrictions has also almost no effect on the solution: the CHP and the storage power is slightly increased to be able to meet the demand. Thus during the day more heat is produced and stored to be realised in the night when the CHP engine cannot be run. The energy production profiles follow the same pattern that the reference case.

In case that the CHP technology is not available, the biomass power is increased to replace the CHP engines and thereby satisfy

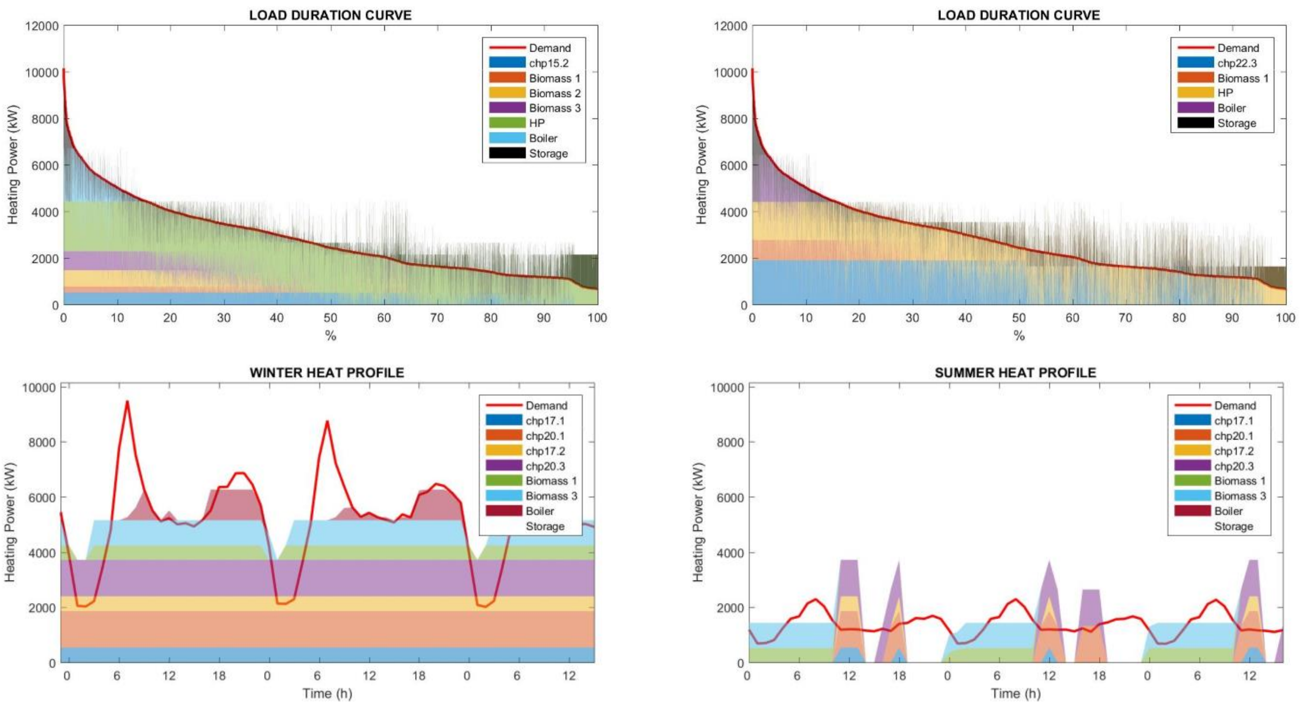

Fig. 18. Case study: HP technology not available. Winter (left) and summer (right) heat profiles. Electricity production profiles are not relevant and have been omitted.

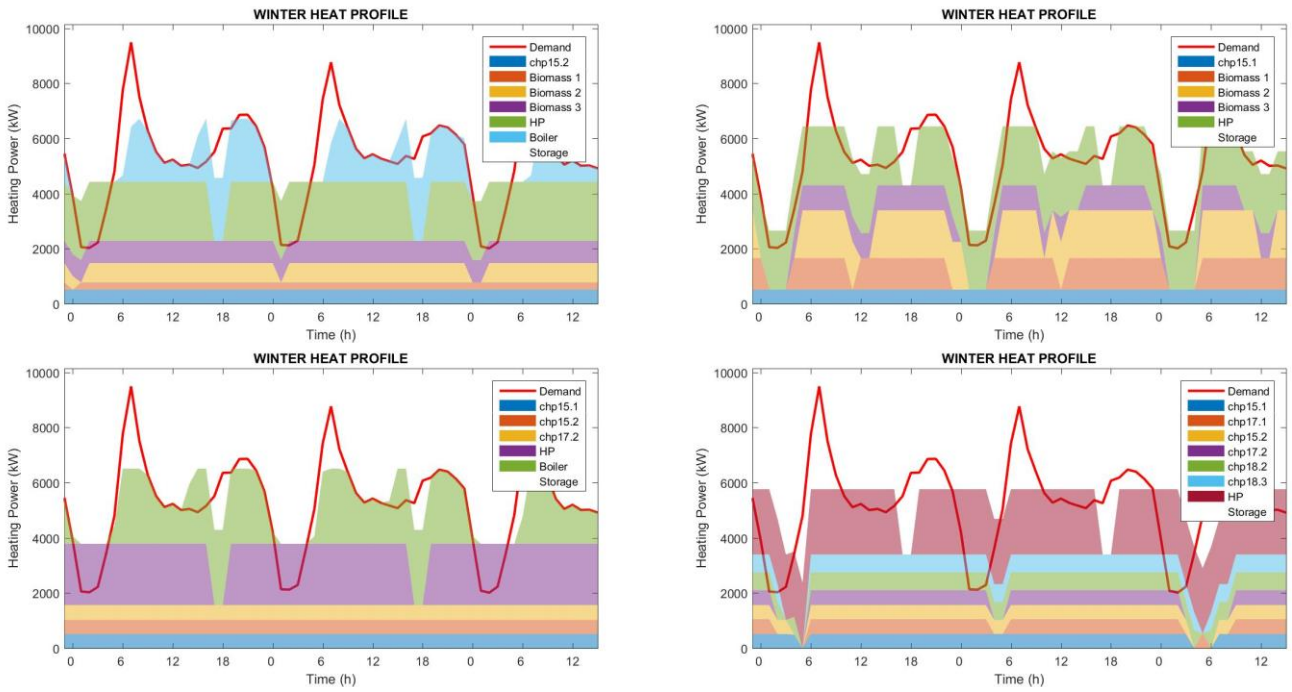

Fig. 19. Winter heat production profile. Top to bottom and left to right: Reference case, natural gas boiler technology not available case study, biomass boiler technology not available case study and boiler technology (both biomass and NG) not available case study.

the heat demand (See Table 6). Again, the energy profiles are essentially the same than in the reference case except that the CHP heat is substituted by biomass heat and that all the electricity required is imported from the grid.

The unavailability of HP technology causes a greater presence of CHP technology in the optimal mix of technologies as well as an increase in the storage capacity to intensify the balance of the heat demand (since the CHP technology minimum part load is more restrictive, more storage is needed to match production and consumption). The energy profiles are shown in Fig. 18 and they follow the principles already mentioned in the section: CHP running during the whole day in winter and when the electricity price is the highest in summer, boilers to top up the demand, biomass boilers preferred than natural gas ones, etc.

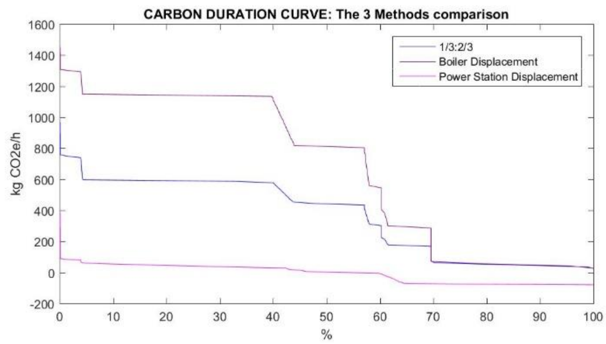

Fig. 21. Case study: ORC modules available. Carbon duration curve considering the 3 methodologies presented by DECC [40].

Fig. 19 condenses the influence in the winter heat profile of the non-existence of biomass boiler technology, natural gas boiler technology or both. Given the unavailability of NG boilers, this technology is replaced in the optimal mix by an increase in the biomass boiler technology power (From 1770kWth to 3786kWh, to cover the necessities). The running hours of the NG boilers are replaced by biomass boilers use and no more changes apply. However, in case of unavailability of biomass boiler technology, the missing heating power is provided by two additional CHP engines, which are run during the whole day in winter. Paradoxically, this solution reports a better annual profit than the reference case because of the solver tolerance stopping criteria [56]. Subject to none of the boiler technologies can be used, 5 more CHP engines are included into the optimal mix, multiplying several times the CHP power capacity, and the TES capacity is tripled to adapt the demand to the optimal CHP heat production. The HP power and its activity remain practically the same. Nevertheless, contrary to the reference case, some CHP engines stop at around 6am when the storage is full and the selling

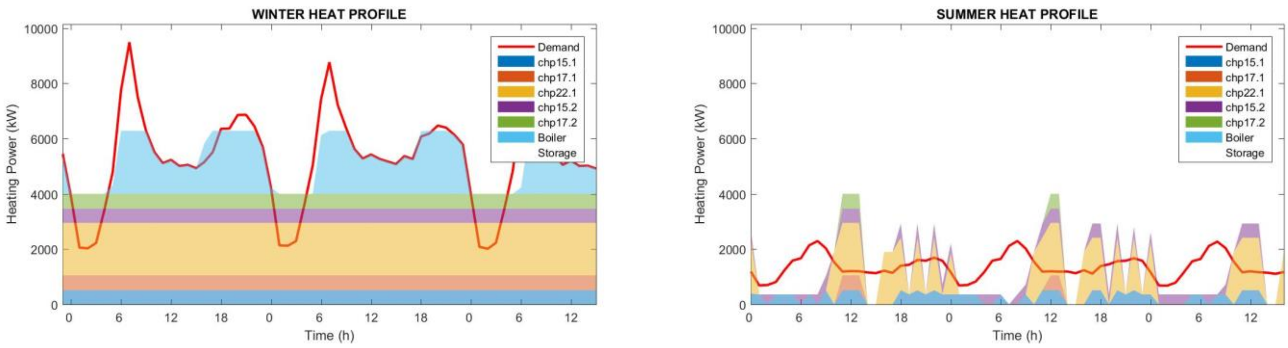

Fig. 22. Case study: RHI removed. Winter (left) and summer (right) heat profiles. Electricity production profiles are not relevant and have been omitted.

Table 6
Case study results. Summary.

	CASE STUDY	Area [m²]	Annual Profit [£]	Annual carbon emissions. 1/3:2/3 disp. [CO2e]	Annual carbon emissions. Boiler disp. [CO2e]	Annual carbon emissions. Power station disp. [CO2e]	Optimal technology mix: CHP engines	CHP total power [kWth]	Biomass boiler unit 1 [kWth]	Biomass boiler unit 2 [kWth]	Biomass boiler unit 3 [kWth]	Biomass total power [kWth]	HP power [kWth]	NG Boiler power [kWth]	TES capacity [kWh]
0	Reference Case	434	4.83E+05	2.62E+06	2.63E+06	2.61E+06	15	512.8	262.5	701.0	806.9	1770.3	2144.7	2288.3	7326.2
1	Grid electricity price 25% reduced	440	5.36E+05	2.79E+06	2.82E+06	2.77E+06	15, 15	1025.6	0.0	610.3	355.5	965.8	2328.4	2106.4	7958.6
1	Grid electricity price 25% increased	484	7.01E+05	3.70E+06	5.78E+06	1.18E+06	22, 22, 22	5701.9	0.0	0.0	0.0	0.0	0.0	0.0	23482.6
1	External electricity demand existence	460	7.22E+05	4.78E+06	4.96E+06	4.57E+06	15, 15, 17, 17	2100.9	543.5	0.0	0.0	543.5	1798.5	1957.9	8761.0
1	Secondary market existence	437	7.52E+05	3.76E+06	5.79E+06	1.31E+06	17, 17, 22, 22	4876.6	109.6	100.0	0.0	209.6	0.0	1280.5	8974.5
2	Gas price 25% reduced	380	6.52E+05	3.61E+06	5.30E+06	1.57E+06	22, 22	3801.3	0.0	0.0	0.0	0.0	367.9	1987.6	12999.2
2	Gas price 25% increased	438	4.54E+05	2.45E+06	2.45E+06	2.44E+06	15	512.8	617.4	1003.6	1234.9	2856.0	2076.3	1258.7	7398.1
3	Carbon driven strategy, 1/3:2/3 Methodology	2176	-5.13E+06	7.98E+05	7.98E+05	7.97E+05	9	242.3	2757.5	4475.6	1193.0	8426.1	0.0	0.0	30000.0
3	Carbon driven strategy, boiler displacement	2228	-5.22E+06	8.20E+05	8.20E+05	8.20E+05	9	242.3	1803.4	5551.1	2122.3	9476.8	517.9	0.0	30000.0
3	Carbon driven strategy, power station disp.	2199	-5.14E+06	7.98E+05	8.00E+05	7.96E+05	9	242.3	1164.1	3561.5	4642.3	9367.8	0.0	0.0	30000.0
3	50% savings in carbon emissions (power station disp.)	408	4.12E+05	2.24E+06	3.02E+06	1.31E+06	22	1900.6	1450.8	1616.0	1024.4	4091.3	578.7	0.0	8267.5
4	Area driven strategy	232	1.74E+05	5.50E+06	5.50E+06	5.50E+06	-	0.0	0.0	0.0	0.0	0.0	0.0	7888.0	3022.0
4	10% reduction in required area	374	4.82E+05	2.92E+06	3.50E+06	2.22E+06	22	1900.6	872.2	0.0	0.0	872.2	1635.3	2018.0	7958.6
4	20% reduction in required area	347	4.74E+05	3.50E+06	4.07E+06	2.82E+06	17, 20	1860.3	0.0	0.0	0.0	0.0	1219.3	4635.1	3542.0
5	Solar heat availability	428	4.93E+05	2.38E+06	2.38E+06	2.37E+06	15	512.8	742.2	633.1	758.5	2133.7	1970.6	2030.8	7152.0
5	ORC modules availability	509	1.70E+06	3.13E+06	5.80E+06	-8.93E+04	22, 22, 22	4920.8	0.0	0.0	0.0	0.0	0.0	771.2	17558.8
5	Night noise council restrictions	443	4.71E+05	2.58E+06	2.59E+06	2.57E+06	17	537.7	709.9	730.2	593.3	2033.4	2122.3	2009.6	8230.5
5	CHP technology unavailability	404	4.25E+05	2.59E+06	2.59E+06	2.59E+06	-	0.0	1829.5	395.2	100.0	2324.7	2122.3	2306.0	6650.2
5	HP technology unavailability	452	3.77E+05	3.19E+06	4.59E+06	1.50E+06	17, 17, 20, 20	3720.6	519.4	0.0	915.9	1435.2	0.0	1113.6	10718.7
5	NG boilers technology unavailability	457	4.73E+05	2.42E+06	2.42E+06	2.41E+06	15	512.8	1147.0	1732.9	906.2	3786.0	2141.4	0.0	9499.7
5	Biomass boilers technology unavailability	414	5.05E+05	3.19E+06	3.36E+06	2.99E+06	15, 15, 17	1563.2	0.0	0.0	0.0	0.0	2222.1	2728.0	7692.2
5	Boilers technology unavailability	604	3.83E+05	3.18E+06	3.55E+06	2.73E+06	15, 15, 17, 17, 18, 18	3397.1	0.0	0.0	0.0	0.0	2368.7	0.0	21224.4
6	RHI 25% increased	442	6.09E+05	2.51E+06	2.51E+06	2.50E+06	15	512.8	1033.2	1325.5	860.5	3219.3	2285.3	584.6	7258.8
6	RHI 25% reduced	428	4.28E+05	3.40E+06	3.82E+06	2.90E+06	15, 15, 17, 17	2100.9	0.0	0.0	0.0	0.0	1644.0	2661.4	8463.8
6	RHI removed	424	3.65E+05	4.04E+06	5.77E+06	1.95E+06	15, 15, 17, 17, 22	4001.6	0.0	0.0	0.0	0.0	0.0	2287.1	10371.3

electricity price quite low. In the three case studies, the summer heat profile remains nearly unaltered: heat demand satisfy by HP and stored heat.

The case studies proposed prove that the unavailability of any of the technologies does not induce unprofitability in the scheme.

5.7. Renewable heat incentive subsidy

The increase (25% up in the case study proposed) in the RHI government subsidy triggers the displacement of NG boiler power per biomass boiler power (Approximately 1500kWth are displaced. See Table 6), resulting an optimal technology mix and an operation strategy similar to the one obtained when NG boiler technology is not available (See Fig. 19). Oppositely, in case that the RHI is reduced a 25%, the biomass technology is displaced in favour of an increased in CHP power. The resulting scheme is almost identical to solution obtained when biomass technology is not available but with one more CHP engine. The annual carbon emissions decrease in the first case and increase in the second one, according to any of the three DECC methodologies [40]. The annual profit behaviour is the opposite. The HP power remains practically constant in both cases.

However, if the RHI is completely removed, the HP technology also becomes unprofitable and is displaced by CHP power too. The TES capacity slightly increases, being the NG boiler power almost the same. The heat profiles are presented in Fig. 22. In this case, while the annual carbon emissions highly increase according to the 1/3:2/3 and boiler displacement methodologies, they decrease if the power displacement methodology is applied due to the extensive grid exports. Even though the RHI is removed, the energy centre is profitable (25% reduction in annual profit in comparison with the reference case. See table 6).

6. Concluding remarks and future work

The Energy Centre Synthesis Model, formulated as a Mix Integer Linear Problem (superstructure, including all the technologies and equipment available, from which the optimal solution is synthesised), has been developed and applied to assess the influence of different parameters into the optimal centralized mix of technologies and the consequent optimal operation strategy. In general, the optimal technology mix tends to include all the technologies proposed: CHP, HP, biomass and NG boilers and TES. In winter the CHP, HP and biomass boilers are used to satisfy the baseload heat demand. The storage is used to balance the demand and to cut the peaks and the NG boiler to top up the demand when it is needed. While in summer, the heat requirements are commonly met by HP in harmony with TES, being the CHP sometimes also used when the price signal is high. However, the increase of the electricity price, the decrease of the gas price, the existence of an external electricity demand or an electricity secondary market, the availability of ORC modules, the unavailability of HP or biomass boilers and the reduction of the RHI promote the displacement of the HP and biomass boiler technology by CHP technology. To match the optimal CHP heat production (during electricity high price periods and to make the most of the exports) with the demand and to overcome the high CHP minimum part load constraint more storage capacity is needed. In these cases, the electricity exports are extensive and the difference between the three DECC carbon emission methodologies is observed (the annual emissions can even take negative values due to the huge energy exports, according to the power station displacement methodology). The boost in the annual profit when the electricity price is increased, when there is a secondary electricity market or an external electricity demand and, specially, when the ORC modules area available (the annual profit is tripled) evidence the importance of the CHP technology and the electricity integration in the district energy centres. Nevertheless, it has been demonstrated that none of the technologies are indispensable in economic terms. Additionally, it has been also evidenced that the RHI government subsidies are needed to make HP and biomass boiler (the most sensible to the RHI) technology profitable or otherwise these technologies are not included in the optimal mix solution. The optimal mix as well as the annual profit is not critically sensible to gas price increase or to a decrease in the grid electricity price.

The three DECC methodologies show that a technology mix mainly based on biomass boiler technology reports the least annual emissions (the same annual carbon emission result is obtained: 30% reduction in comparison with the reference case). Although this scheme is completely unprofitable. However, it has been proved that 50% savings in annual carbon emissions, according to the power station displacement methodology, can be obtained compromising the annual profit only a 15%. Regarding the area footprint required by the optimal technology mix, reductions up to 20% have a small influence in the annual profit, being the area reduction boundary 64% compared to the reference case.

Optimization under uncertainty, specially the consideration of stochastic energy demand and electricity prices, arises as the main future research area. Additionally, other areas of research should be explored: 1) the integration of a demand estimation model to enable the assessment of the influence of the demand in the energy centre design and in the operation scheme; 2) the expansion of the time spam to 20 or 30 years (Energy centre lifetime), taking rigorous guesses of the evolution of the model economic parameters (electricity prices, interest rate, etc.) over the years; and 3) the application of a modified version of the ECS model to plan energy centre expansions and to determine and size the optimal network and the location of the technology. Finally, it is the belief of the authors that future work should also be addressed to a further urban energy integration and business model consideration, including, for example, electrical vehicles demand in the scheme.

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9. Nomenclature

9.1. Abbreviations

CAPEX	Capital expenditure
CF	Carbon factors
CHP	Combined heat and power engines
CO2e	Carbon dioxide equivalent
COP	Heat pumps coefficient of performance
DE	District energy
DECC	Department of Energy & Climate Change
Disp.	Displacement
DH	District heating
DHN	District heating network

DHW	Domestic Hot Water
ECS	Energy Centre Synthesis Model
$Elect.$	Electricity
$F.$	Function
EXT	Exterior
HP	Heat pumps
INT	Interior
INV or Invest.	Investment
KPI	Key Performance Indicator
Maint.	Maintenance
MILP	Mix Integer Linear Problem
M&S	Marshall & Swift factor
NG	Natural Gas
OP	Operational
OPEX	Operational expenses
ORC	Organic Rankine cycle modules for CHPs
PL	Part Load
RHI	Renewable heat incentive subsidy
Tech.	Technology
TES	Thermal energy storage
TOT	Total
Var.	Variable

9.2. Sets

$T = \{1,2, \dots, 8760\}$	Set of time periods: 8760 hourly time periods for one year $[h]$
$\Theta = \begin{Bmatrix} CHP_1, CHP_2, \dots, CHP_n, ORC_{CHP_1}, ORC_{CHP_2}, \dots, ORC_{CHP_n}, HP, \\ biomass_1,\ biomass_2, \dots,\ biomass_m, boiler, TES \end{Bmatrix}$	Set of technologies $[-]$
$\Upsilon = \{\ biomass_1,\ biomass_2, \dots,\ biomass_m\}$	Set of biomass units $[-]$
$\Phi = \{Community, Commercial, NHS, Other\ Public, Other\}$	Set of costumers $[-]$
$\Psi = \{CHP_1, CHP_2, \dots, CHP_n\}$	Set of Combine Heat and Power engines (CHP) $[-]$
$\Omega = \{ORC_{CHP_1}, ORC_{CHP_2}, \dots, ORC_{CHP_n}\}$	Set of Organic Rankine Cycle (ORC) modules for CHPs $[-]$

9.3. Continuous variables

A_i	Area required per technology $i \in \Theta$ $[m^2]$
C_i^{INV}	Annual investment cost of technology $i \in \Theta$ [£]
$C_t^{Boilers}$	Cost related to the Boiler and the Biomass boiler heat production at period $t \in T$ [£]
$C_t^{CHP,HP,Elect}$	Costs result related to the CHP and HP heat production and the electricity imports and exports at period $t \in T$ [£]
C_t^{OP}	Total cost resulting from the operation of the plant at time $t \in T$ [£]
$CO2e_t^j$	CO2e intensity of the scheme at time period $t \in T$ according to the DECC methodology $j \in \{1,2,3\}$ $[KgCO_2e]$
E_t^{CHP}	Electricity generated by the CHP at time period $t \in T$ $[kWh]$
$E_t^{CHP \to HP}$	Electricity generated by the CHP and consumed by the heat pump at time $t \in T$ $[kWh]$
$E_t^{CHP \to Market2}$	Electricity generated by the CHP and sold to a secondary market at time $t \in T$ $[kWh]$
$E_t^{CHP \to grid}$	Electricity generated by the CHP and sold to the grid at time $t \in T$ $[kWh]$
E_t^{HP}	Total electricity consumed by the heat pump at time $t \in T$ $[kWh]$
$E_t^{grid \to DH}$	Electricity purchased from the grid at time $t \in T$ $[kWh]$
$E_t^{grid \to HP}$	Electricity purchased from the grid and consumed by the heat pump at time $t \in T$ $[kWh]$
G_t^{CHP}	Natural gas consumed by the CHP units, with and without the ORC modules, at time $t \in T$ $[kWh]$
L_t	Heat level of the thermal energy storage at time $t \in T$ $[kWh]$
P^{TOT}	Total annual profit discounting the investment costs [£]
Q_t^i	Production of heat by technology $i \in \Theta$ at time $t \in T$ $[kW]$
R_t^{OP}	Revenue resulting from selling heat and electricity to the network consumers at period $t \in T$ [£]
S_i	Size of technology $i \in \Theta$ $[kWth\ or\ kWh]$

9.4. Integer variables

X_i	Binary variable equal to 1 if unit $i \in \Theta$ exists $[-]$
y_t^i	Binary variable equal to 1 if unit $i \in \Theta$ is active at time period $t \in T$ $[-]$

9.5. Parameters

A^{Max}	Maximum area available for building the DH centre $[m^2]$
An_i	Annuity Factor of technology $i \in \Theta$ $[-]$
A_t^{losses}	Thermal energy storage heat exchange area at time $t \in T$ $[m^2]$
C_i^{Fix}	Investment fixed cost of technology $i \in \Theta$ [£]
$C_i^{Maint.}$	Fixed (Not investment dependent) maintenance cost of technology $i \in \Theta$ [£]
C_i^{Var}	Investment variable (size dependent) cost of technology $i \in \Theta$ $[£/(kWth\ or\ kWh)]$
$CF^{biomass}$	Biomass Carbon Factor $[KgCO_2e/kWh]$
CF^{gas}	Natural Gas Carbon Factor $[KgCO_2e/kWh]$
$CF_{i,j}^{CHP\ elect/gas}$	CHP elect. CF: Gas Carbon Factor ratio for the unit $i \in (\Psi \cup \Omega)$ according to the DECC methodology $j \in \{1,2,3\}$ $[-]$
$CF_j^{CHP\ elect/gas}$	Average CHP electricity Carbon Factor : Gas Carbon Factor ratio according to the DECC methodology $j \in \{1,2,3\}$ $[-]$

CF_t^{grid}	Grid Electricity Carbon Factors at time $t \in T$ $[KgCO_2e/kWh]$
COP_t	Coefficient of performance of the Heat Pump at time $t \in T$ $[kWth/kWe]$
$D_t^{Elect,EXT}$	External electricity demand for the scheme at time $t \in T$
$D_t^{Elect,INT}$	Internal electricity demand for the scheme at time $t \in T$ $[kWh]$
D_t^{Heat}	Total heat demand for the scheme at time $t \in T$ $[kW]$
F_i	Maintenance Factor of technology $i \in \Theta$ $[£_{Maint.}/£_{Tech.\ Invest}]$
L_0	Initial storage level $[kWh]$
M	Arbitrary large value $[-]$
$M_{0,i}$	Reference M&S of the year for which the investment cost factors and parameters of tech. $i \in \Theta$ are known $[-]$
M_{2016}	Marshall & Swift factor for the year 2016 $[-]$
N_i	Asset lifetime for technology $i \in \Theta$ $[y]$
NR_t^i	Binary parameter equal to 0 if the unit $i \in (\Psi \cup \Omega)$ cannot be operated at $t \in T$ due to noise restrictions $[-]$
ORC_i	Binary parameter equal to 1 if the ORC module $i \in \Omega$ is available to be added to the corresponding CHP $[-]$
Q_{TES}^{Max}	Maximum heat power (charging and discharging) of the thermal energy storage $[kWth]$
Q_t^{Other}	Available heat from any other source (Waste heat, geothermal heat, etc.) at time $t \in T$ $[kW]$
Q_t^{Solar}	Insulation or Solar heat at time $t \in T$ $[kW]$
$R^2{}_{area,i}$	Linear regression R-square value of the linear area function depending on the size for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
$R^2{}_{elect,i}$	Linear regression R-square value of the linear power output f.. depending on the PL for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
$R^2{}_{fuel,i}$	Linear regression R-square value of the linear fuel consumption f. depending on the PL for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
S_i^{Max}	Maximum size for technology $i \in \Theta$ $[kWth\ or\ kWh]$
S_i^{Min}	Maximum size for technology $i \in \gamma$ $[kWth]$
T_r	District heating network return temperature [°C]
T_s	District heating network supply temperature [°C]
T_t^{TES}	Thermal energy storage temperature at time $t \in T$ [°C]
T_t^{air}	Ambient temperature (external wall of the thermal energy storage) at time $t \in T$ [°C]
V	Thermal energy storage volume $[m^3]$
a_i	Slope of the linear fuel consumption function depending on the part load for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
b_i	Independent term of the linear fuel consumption function depending on the part load for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
$c_{e_{H_2O}}$	Water specific heat capacity $[J/(°C \cdot kg)]$
f	Unit conversion factor $[kwh/J]$
$p^{Elect,EXT}$	External demand electricity price $[£/MWh]$
p_{HP}^{RHI}	Value of the renewable heat incentive subsidy for HP technology $[£/MWh]$
$p_{biomass}^{RHI}$	Value of the renewable heat incentive subsidy for biomass boilers units $[£/MWh]$
p_k^{Heat}	Heat price for costumer $k \in \Phi$ $[£/MWh]$
p_t^{Market}	Secondary Market electricity export price at time $t \in T$ $[£/MWh]$
$p_t^{biomass}$	Price of biomass at time $t \in T$ $[£/MWh]$
p_t^{gas}	Price of natural gas at time $t \in T$ $[£/MWh]$
$p_t^{grid,buy}$	Grid electricity import price at time $t \in T$ $[£/MWh]$
$p_t^{grid,sell}$	Grid electricity export price at time $t \in T$ $[£/MWh]$
q_i	Slope of the linear power output function depending on the part load for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
q_t^{losses}	Heat loss power of the thermal energy storage at time $t \in T$ $[w]$
r	Interest rate $[-]$
s	Thermal energy storage heat insulation thickness $[m]$
u_i	Slope of the linear area function depending on the size for unit $i \in (\Psi \cup \Omega)$ $[m^2/(kWth\ or\ kWh)]$
v_i	Independent term of the linear area function depending on the size for unit $i \in (\Psi \cup \Omega)$ $[m^2]$
z_i	Independent term of the linear power output function depending on the part load for unit $i \in (\Psi \cup \Omega)$ $[kWh]$
Δt	Time increment equal to a model time period $[s]$
$\Pi_j^{CO_2}$	Maximum Carbon emissions per year constraint for DECC methodology $j \in \{1,2,3\}$ $[KgCO_2e]$
χ_k	Parts per unit of costumer $k \in \Phi$ $[-]$
ε	Thermal energy storage height-diameter ratio $[-]$
ζ	Rate of heat loss for thermal energy storage $[-]$
$\eta_{biomass}$	Biomass boiler units boiler thermal efficiency $[kWh/kWh_{fuel}]$
η_{boiler}	Gas boiler thermal efficiency $[kWh/kWh_{fuel}]$
K_i	Minimum part load for technology $i \in \Theta$ $[kWth\ or\ kWh]$
λ	Thermal conductivity of the thermal energy storage heat insulation $[w/(m \cdot °C)]$
π	The irrational mathematical constant PI $[-]$
$\pi_j^{CO_2}$	Maximum Carbon emissions intensity constraint for DECC methodology $j \in \{1,2,3\}$ $[KgCO_2e/h]$
π_t^{Market}	Maximum electricity exports for secondary market capacity at time $t \in T$ $[kWh]$
ρ	Water density at the average temperature between T_s and T_r $[kg/m^3]$
τ_i^{Min}	Minimum running time between shut-downs for unit $i \in (\Theta - \mathrm{TES})$ $[h]$

10. Appendix

Table 7
Theoretical Capacity, Electrical and Heat output and efficiencies at 100% part load, CAPEX and maintenance cost and electrical efficiency at 75% part load of each CHP unit, with and without ORC, considered in this paper. Capacity, efficiency and cost data retrieved from several CHP manufacturers. Note that the costs parameters may not exactly correspond to the actual values due to commercial confidentiality issues.

Unit	Tag	Theoretical Capacity	Electrical Output $[kWe]$ @100%	Heat Output $[kWth]$ @100%	CAPEX $[£]$	Maintenance $[£]$	Electrical Efficiency @100%	Thermal Efficiency @100%	Electrical Efficiency @75%
UNIT 90	chp1	280	90	163	151,000	17,616	0.321	0.582	0.300
UNIT 100	chp2	305	100	175	151,000	17,616	0.328	0.574	0.308
UNIT 110	chp3	329	110	186	151,000	18,935	0.334	0.565	0.315
UNIT 125	chp4	357	122	198	151,000	19,548	0.342	0.554	0.324
UNIT 135	chp5	396	135	219	173,000	20,998	0.341	0.552	0.318
UNIT 150	chp6	427	150	233	173,000	21,481	0.351	0.546	0.328
UNIT 165	chp7	505	165	285	195,000	22,302	0.327	0.564	0.303
UNIT 185	chp8	551	185	309	195,000	22,544	0.336	0.561	0.312
UNIT 200M	chp9	518	205	242	235,000	23,358	0.396	0.468	0.384
UNIT 210	chp10	607	210	337	198,000	22,753	0.346	0.556	0.323
UNIT 230	chp11	647	229	356	198,000	24,747	0.354	0.551	0.331
UNIT 250M	chp12	679	254	321	245,000	31,287	0.374	0.472	0.365
UNIT 310	chp13	820	310	357	214,243	38,769	0.378	0.435	0.367
UNIT 375	chp14	972	376	398	230,000	38,769	0.387	0.410	0.374
UNIT E400M	chp15	1047	405	513	233,333	39,498	0.387	0.490	0.380
UNIT 425	chp16	1106	426	464	247,000	43,393	0.385	0.419	0.374
UNIT 500	chp17	1321	502	538	258,000	43,393	0.380	0.407	0.380
UNIT E530M	chp18	1342	530	648	316,940	56,784	0.395	0.483	0.388
UNIT E770	chp19	1832	775	823	875,000	67,411	0.423	0.449	0.408
UNIT 1280	chp20	2972	1284	1323	1,020,000	111,708	0.432	0.445	0.418
UNIT 1520	chp21	3437	1519	1402	1,250,000	132,153	0.442	0.408	0.433
UNIT 2020	chp22	4569	2024	1901	1,550,000	176,088	0.443	0.416	0.434
ORC UNIT 90	ORC chp1	280	112	141	229,244	19,404	0.401	0.502	0.382
ORC UNIT 100	ORC chp2	305	124	151	232,648	19,534	0.407	0.495	0.389
ORC UNIT 110	ORC chp3	329	135	161	235,409	20,974	0.411	0.488	0.396
ORC UNIT 125	ORC chp4	357	149	171	238,090	21,714	0.418	0.478	0.403
ORC UNIT 135	ORC chp5	396	165	189	266,477	23,393	0.417	0.476	0.394
ORC UNIT 150	ORC chp6	427	182	201	269,788	24,038	0.426	0.471	0.404
ORC UNIT 165	ORC chp7	505	204	246	309,366	25,421	0.404	0.487	0.380
ORC UNIT 185	ORC chp8	551	227	267	315,134	25,929	0.413	0.484	0.389
ORC UNIT 200M	ORC chp9	518	238	209	326,092	26,013	0.460	0.404	0.449
ORC UNIT 210	ORC chp10	607	256	291	320,514	26,452	0.422	0.480	0.400
ORC UNIT 230	ORC chp11	647	278	308	322,793	28,654	0.429	0.476	0.408
ORC UNIT 250M	ORC chp12	679	298	277	353,083	34,800	0.439	0.407	0.430
ORC UNIT 310	ORC chp13	820	359	308	329,911	42,679	0.438	0.375	0.431
ORC UNIT 375	ORC chp14	972	431	344	354,003	43,135	0.443	0.354	0.435
ORC UNIT E400M	ORC chp15	1047	475	443	386,327	45,118	0.454	0.423	0.450
ORC UNIT 425	ORC chp16	1106	490	400	379,325	48,474	0.442	0.362	0.437
ORC UNIT 500	ORC chp17	1321	576	464	404,503	49,286	0.436	0.351	0.441
ORC UNIT E530M	ORC chp18	1342	619	559	485,141	63,887	0.461	0.417	0.455
ORC UNIT E770	ORC chp19	1832	888	710	1,077,862	76,427	0.485	0.387	0.471
ORC UNIT 1280	ORC chp20	2972	1465	1141	1,346,163	126,204	0.493	0.384	0.481
ORC UNIT 1520	ORC chp21	3437	1711	1210	1,595,771	147,521	0.498	0.352	0.491
ORC UNIT 2020	ORC chp22	4569	2284	1640	2,018,698	196,919	0.500	0.359	0.492

Table 8
Electrical efficiency at 75% part load, Heat and electrical efficiency at 50% part load and slope, intercept and linear regression R-square values of the linear fuel consumption (a_i, b_i and $R^2{}_{fuel,i}$, respectively) and the power output function depending on the part load (q_i, z_i and $R^2{}_{elect.,i}$, respectively) of each CHP unit, with and without ORC, considered in this paper. Efficiency data retrieved from several CHP manufacturers.

Unit	Tag	Thermal Efficiency @75%	Electrical Efficiency @50%	Thermal Efficiency @50%	a_i	b_i	$R^2{}_{fuel,i}$	q_i	z_i	$R^2{}_{elect.,i}$
UNIT 90	chp1	0.598	0.267	0.611	294	-14.1	1.000	109	-19.2	0.999
UNIT 100	chp2	0.593	0.276	0.609	322	-18.5	1.000	121	-21.2	0.999
UNIT 110	chp3	0.588	0.284	0.606	352	-23.6	0.999	133	-23.5	0.999
UNIT 125	chp4	0.580	0.294	0.602	385	-30.1	0.999	147	-26.3	0.999
UNIT 135	chp5	0.558	0.282	0.551	395	-0.4	1.000	158	-23.8	0.999
UNIT 150	chp6	0.557	0.293	0.554	434	-7.8	0.999	177	-27.5	0.999
UNIT 165	chp7	0.564	0.265	0.553	495	9.2	1.000	194	-29.3	0.999
UNIT 185	chp8	0.565	0.276	0.558	548	1.7	1.000	217	-33.1	0.999
UNIT 200M	chp9	0.476	0.358	0.513	563	-43.8	1.000	241	-35.3	1.000
UNIT 210	chp10	0.564	0.288	0.561	612	-7.1	1.000	247	-37.9	0.999
UNIT 230	chp11	0.563	0.296	0.563	661	-16.1	0.999	271	-43.0	0.999
UNIT 250M	chp12	0.477	0.340	0.494	709	-29.5	1.000	287	-32.8	1.000
UNIT 310	chp13	0.465	0.339	0.514	946	-128.8	1.000	385	-75.6	1.000
UNIT 375	chp14	0.444	0.350	0.490	1130	-164.0	0.999	467	-94.0	0.999
UNIT E400M	chp15	0.510	0.361	0.530	1125	-82.7	0.999	461	-56.8	1.000
UNIT 425	chp16	0.458	0.340	0.508	1300	-201.3	0.998	542	-117.9	0.999

UNIT 500	chp17	0.444	0.354	0.490	1545	-232.6	0.998	616	-114.6	1.000
UNIT E530M	chp18	0.488	0.372	0.495	1374	-33.3	1.000	573	-43.1	1.000
UNIT E770	chp19	0.458	0.389	0.482	1958	-124.0	1.000	886	-112.4	1.000
UNIT 1280	chp20	0.457	0.400	0.473	3148	-180.8	1.000	1449	-170.3	0.999
UNIT 1520	chp21	0.420	0.416	0.433	3635	-206.4	1.000	1691	-175.9	1.000
UNIT 2020	chp22	0.426	0.415	0.438	4798	-237.2	1.000	2247	-226.5	1.000
ORC UNIT 90	ORC chp1	0.516	0.351	0.527	294	-14.1	1.000	131	-19.2	0.999
ORC UNIT 100	ORC chp2	0.512	0.359	0.526	322	-18.5	1.000	145	-21.2	0.999
ORC UNIT 110	ORC chp3	0.507	0.367	0.523	352	-23.6	0.999	158	-23.5	0.999
ORC UNIT 125	ORC chp4	0.501	0.376	0.520	385	-30.1	0.999	175	-26.3	0.999
ORC UNIT 135	ORC chp5	0.482	0.357	0.476	395	-0.4	1.000	188	-23.8	0.999
ORC UNIT 150	ORC chp6	0.481	0.369	0.478	434	-7.8	0.999	209	-27.5	0.999
ORC UNIT 165	ORC chp7	0.487	0.341	0.477	495	9.2	1.000	233	-29.3	1.000
ORC UNIT 185	ORC chp8	0.488	0.352	0.482	548	1.7	1.000	260	-33.1	0.999
ORC UNIT 200M	ORC chp9	0.411	0.428	0.443	563	-43.8	1.000	274	-35.3	1.000
ORC UNIT 210	ORC chp10	0.487	0.365	0.484	612	-7.1	1.000	293	-37.9	0.999
ORC UNIT 230	ORC chp11	0.486	0.373	0.486	661	-16.1	0.999	319	-43.0	0.999
ORC UNIT 250M	ORC chp12	0.412	0.408	0.426	709	-29.5	1.000	331	-32.8	1.000
ORC UNIT 310	ORC chp13	0.401	0.409	0.444	946	-128.8	1.000	434	-75.6	1.000
ORC UNIT 375	ORC chp14	0.383	0.417	0.423	1130	-164.0	0.999	522	-94.0	0.999
ORC UNIT E400M	ORC chp15	0.440	0.434	0.457	1125	-82.7	0.999	531	-56.8	1.000
ORC UNIT 425	ORC chp16	0.395	0.410	0.438	1300	-201.3	0.998	605	-117.9	0.999
ORC UNIT 500	ORC chp17	0.383	0.421	0.423	1545	-232.6	0.998	689	-114.6	1.000
ORC UNIT E530M	ORC chp18	0.421	0.440	0.427	1374	-33.3	1.000	662	-43.1	1.000
ORC UNIT E770	ORC chp19	0.395	0.455	0.416	1958	-124.0	1.000	999	-112.4	1.000
ORC UNIT 1280	ORC chp20	0.394	0.465	0.408	3148	-180.8	1.000	1631	-170.3	1.000
ORC UNIT 1520	ORC chp21	0.362	0.475	0.374	3635	-206.4	1.000	1883	-175.9	1.000
ORC UNIT 2020	ORC chp22	0.368	0.475	0.378	4798	-237.2	1.000	2508	-226.5	1.000

Table 9
Coefficient of performance depending on sink and source temperature of centralised heat pumps using R134a refrigerant [42]. Recommendable for sink temperatures above 75 °C.

Source T	Sink T			
	75 °C	80 °C	85 °C	90 °C
5 °C	3.46	3.23	2.99	2.75
10 °C	3.68	3.42	3.16	2.90
15 °C	3.86	3.56	3.25	2.95
20 °C	4.06	3.71	3.37	3.03
25 °C	4.28	3.89	3.50	3.11
30 °C	4.51	4.07	3.64	3.19
35 °C	4.75	4.26	3.77	3.28
40 °C	5.00	4.45	3.90	3.36
45 °C	5.27	4.66	4.05	3.44
50 °C	5.55	4.88	4.20	3.52

Table 10
Coefficient of performance depending on sink and source temperature of centralised heat pumps using R134a refrigerant [42]. Recommendable for sink temperatures in between 50 °C and 75 °C.

Source T	Sink T									
	30 °C	35 °C	40 °C	45 °C	50 °C	55 °C	60 °C	65 °C	70 °C	75 °C
-15 °C	2.57	2.31	2.07	-	-	-	-	-	-	-
-10 °C	3.12	2.78	2.48	2.21	1.97	-	-	-	-	-
-5 °C	3.76	3.34	2.96	2.62	2.32	2.06	-	-	-	-
0 °C	4.52	4	3.53	3.11	2.74	2.41	2.13	1.88	1.65	-
5 °C	5.42	4.78	4.21	3.69	3.24	2.83	2.48	2.18	1.92	1.69
10 °C	6.51	5.71	5.01	4.38	3.82	3.33	2.9	2.53	2.21	1.93
15 °C	7.81	6.82	5.95	5.18	4.51	3.92	3.4	2.95	2.56	2.22
20 °C	-	-	7.06	6.12	5.31	4.6	3.98	3.44	2.97	2.56

Table 11
Coefficient of performance depending on sink and source temperature of centralised heat pumps using R407c refrigerant [42]. Recommendable for sink temperatures below 50 °C.

Source T	Sink T							
	30 °C	35 °C	40 °C	45 °C	50 °C	55 °C	60 °C	65 °C
-15 °C	2.8	2.44	2.11	-	-	-	-	-
-10 °C	3.41	2.97	2.57	2.22	-	-	-	-
-5 °C	4.13	3.58	3.1	2.66	2.28	-	-	-
0 °C	4.98	4.3	3.71	3.18	2.72	2.32	-	-
5 °C	6.01	5.17	4.44	3.8	3.24	2.75	2.33	1.97
10 °C	7.25	6.2	5.31	4.53	3.86	3.27	2.76	2.33
15 °C	8.74	7.44	6.34	5.4	4.58	3.88	3.27	2.75
20 °C	10.54	8.91	7.57	6.43	5.45	4.6	3.87	3.25