

Optimisation and analysis of system integration between electric vehicles and UK decentralised energy schemes

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Abstract

Although district heat network schemes provide a pragmatic method by which to reduce the environmental impact of urban energy systems, there are additional benefits that could arise from servicing electric vehicles. Using the electricity generated on-site to power electric vehicles can make district heating networks more economically feasible, while also increasing environmental benefits. This paper aims to address the potential integration of electric vehicle charging into a large-scale district heating network to increase the value of the generated electricity and thereby improve the system's financial feasibility. A modelling approach is presented composed of a diverse range of distributed technologies that considers residential and commercial electric vehicle charging demands via agent-based modelling. An existing district heating network system in London was taken as a case study. The energy system was modelled as a mixed integer linear program and optimised for either profit maximisation or carbon dioxide emissions minimisation. Commercial electric vehicles provided the best alternative to increase revenue streams by about 11% against the current system configuration with emissions effectively unchanged. The research indicates district heating network systems need to carefully analyse transport electrification to improve the integration, and sustainability, of urban energy systems.

Keywords: integrated energy systems; district heating networks; combined heat and power; electric vehicles; ESCO; agent-based modelling.

Nomenclature

Key abbreviations

ABM	Agent Based Model
BaU	Business as Usual
CHP	Combined Heat and Power
mCHP	Micro Combined Heat and Power
COP	Coefficient of Performance
DH	District Heating
DHN	District Heating Network
ESCO	Energy Service Company
EV	Electric Vehicle
HP	Heat Pump
LUL	London Underground Limited
MILP	Mixed Integer Linear Program
QI	Quality Index
RHI	Renewable Heat Incentive
TES	Thermal Energy Storage
WHRS	Waste Heat Recovery System

Continuous variables (where $i \in \{\text{CHP1, CHP2, HP, TES, boiler}\}$)

Q_t^i	Heat produced by technology i at time t
D_t	Heat demand at time t
E_t^{CHP}	Electricity produced by CHP at time t
E_t^{HP}	Electricity required to power the HP at time t
E_t^{int}	Electricity required for DHN internal demand at time t
$E_t^{CHP \rightarrow grid}$	Electricity sold to the grid from the DHN at time t
$E_t^{CHP \rightarrow EV}$	Electricity sold for EV charging from the DHN at time t
$E_t^{CHP \rightarrow WHRS}$	Electricity sold to WHRS from the DHN at time t
$E_t^{CHP \rightarrow HP}$	Electricity from CHP used to power the HP at time t
$E_t^{CHP \rightarrow int}$	Electricity from CHP used for DHN internal demand at time t
$E_t^{grid \rightarrow HP}$	Electricity bought from the grid to power the HP at time t
$E_t^{grid \rightarrow int}$	Electricity bought from the grid for DHN internal demand at time t
$p_t^{sell, grid}$	Price of electricity sold to the grid at time t
$p_t^{sell, EV}$	Price of electricity sold to for EV charging at time t
$p_t^{buy, grid}$	Price of electricity bought from the grid at time t
$p_t^{sell, WHRS}$	Price of electricity sold to the WHRS at time t
p_t^{ng}	Price of natural gas at time t
F_t^{CHP}	Natural gas used by CHP1 and CHP2 at time t
F_t^B	Natural gas used by boilers at time t
R_t	Revenue generated by the DHN at time t
C_t	Costs incurred by the DHN at time t
Pr_t	Profit of the DHN at time t
CF_t^{grid}	Carbon factor of the grid at time t
$CO2_t^{DHN}$	Carbon dioxide emissions from the DHN at time t

Parameters

p^{heat}	Price of DHN heat paid by consumers
$Q^{i, max}$	Maximum heat output of technology i
a_i	Slope coefficient used in function to convert part load to fuel usage of technology i
b_i	Intercept used in function to convert part load to fuel usage of technology i
η_{boiler}	Efficiency of boilers
CF^{NG}	Carbon factor of natural gas

1. Introduction

Climate change is at the forefront of the issues plaguing society today, with increasing international concern about rising global temperatures. The UK aims to achieve an 80% reduction in greenhouse gas emissions, from 1990 levels, by 2050 [1]. Since heat constitutes approximately 44% of domestic energy use [2], it is essential to develop practical methods to decarbonise this sector. District heating (DH) provides an effective means of doing so, as it exploits the benefits of centralised heat production instead of individual gas boilers, which are used in most households and commercial buildings today [3].

Typically, centralised power stations in the UK produce electricity with efficiencies between 35-45% and domestic heat demand is provided using stand-alone boilers with efficiencies between 80-90% [4]. The use of combined heat and power (CHP) production has the advantage of high efficiencies due to the potential to utilise thermal energy, which would otherwise be wasted, for district heating networks (DHNs) [5]. Such heat networks are well established in various European countries, for example DH provides 62% of Danish residential heat supply [3]. According to the Department of Energy and Climate Change (DECC), such heat networks will be critical in the decarbonisation of residential and commercial heat supply, due to reduced fossil fuel consumption through integration of waste heat and low carbon sources [1]. However, despite DH being present in the UK since the 1950s, there has been very low market penetration, with DH only supplying around 2% of the UK heat demand [6].

One key barrier to the widespread adoption of DHNs is the selling price of electricity from combined heat and power stations (CHPs) [7]. Electricity in the UK is a more valuable commodity than heat [7] and therefore the financial viability of a CHP-supplied DH network is heavily influenced by electricity commercial trading schemes, which leaves such systems vulnerable to export tariffs that can be agreed. In addition, it is not practical to sell electricity, bypassing the existing infrastructure, to nearby properties, as this requires installing an expensive network of private wires [8]. Therefore, one method by which DH networks could increase the value of CHP electricity output is by catering to electric vehicle (EV) charging demand. This could potentially lead to higher electricity selling prices and also caters to a growing market [9], thus possibly leading to increasing economic and environmental benefit over time. Therefore, as long as the electricity sold to the EV charging stations is priced between the buying and selling price of the grid, there is motivation for all stakeholders involved in this system to adopt it, assuming this price is high enough to pay back the capital investments. Energy Service Companies (ESCOs) can also explore existing measures as an additional source of revenue, such as enhanced capital allowances and preferential business rates [10]. However, the remaining challenge is to quantify this benefit and to explore how it is affected by various aspects of the system such as fuel prices, EV charging demand, etc.

While DHNs are still likely to play a pivotal role in the future, the relative importance of CHP may decrease compared to variable renewables [11]. However, existing DHNs predominantly utilise CHP and as such, this paper focuses on system integration of current assets rather than that of potential future DHNs.

To the best of the authors' knowledge, the integration of DHNs and EV charging has not been explored within a large-scale urban setting, while taking urban driver behaviour scenarios into account, and this paper aims to address this research gap. Furthermore, the use of agent-based modelling to simulate EV charging demand, together with the level of granularity achieved through the use of hourly time intervals for the simulation, provide a novel approach for framing this topic.

In this paper, a CHP-DH-EV hybrid system is analysed as a potential investment route for a council or a potential ESCO in their goal to become more energy efficient, while also increasing revenue. In Section 2 the current literature is analysed, in Section 3 the

methodology used in this study is outlined. Finally, Sections 4 and 5 present the key results and conclusions respectively.

2. District heat network and electric vehicle integration challenges

Buildings are responsible for 40% of the total energy consumption in EU member states [12], so reducing, or increasing the sustainability of, this use is a key factor in reducing fossil-fuel dependence in urban areas and achieving the EU's 20-20-20 goals of 20% increase in energy efficiency, 20% reduction in CO₂ emissions, and 20% renewables by 2020 [12]. There are currently at least two key schools of thought regarding the viable methods by which to achieve this. One viewpoint is that future properties will be either low-energy or plus-energy [13], thus potentially reducing the need for district heating. Another is that excess heat production from industrial activities, waste incineration and power stations could be used in conjunction with renewable sources such as geothermal or large scale solar thermal energy, as well as large-scale heat pumps that could be powered from renewable sources, e.g. wind/solar power. The latter of the two scenarios validates the necessity of DH networks in moving towards sustainable urban energy systems. While the concept of low-energy buildings, zero-carbon and plus-energy houses has been analysed in recent literature, these are mostly future-oriented as current buildings are unlikely to be retrofitted and will still last for many years to come [13]. Therefore, the use of DH currently represents a feasible and effective way to reduce energy consumption and combat climate change.

The key components of a DH network (DHN) are [14]:

- Plant(s) where thermal energy is produced to warm a heating fluid
- A group of customers who are connected to the heat network and represent the heat demand
- A set of insulated pipes to transfer the heating fluid from the plant(s) to the consumers and back

From the related literature, it is seen that at the heart of DH systems is typically at least one CHP unit [14]. Simply put, a CHP or cogeneration system is able to simultaneously generate useful heat and power. There are various types of CHP plants such as gas turbine, steam turbine and biofuel engines to name a few. In the case of gas turbines, power is generated via alternators and the by-product energy from the exhaust gases is used for heating. This is a far more energy efficient system that can achieve 30% energy savings compared to separate heat and power production [15].

One measure the UK has taken to expand CHP adoption is the CHP Quality Assurance Scheme, where successful certification brings a range of benefits, including Renewable Obligation Certificates, Enhanced Capital Allowances, preferential Business Rates, etc. [10]. Despite the support surrounding CHP, there are still certain limitations. Literature suggests that for a payback period of 4-5 years, the unit needs to be fully utilised, i.e. both heat and power, for 4500 hours per year [16]. The low heat demand during summer can make this criterion difficult to achieve without a shared use of this heat.

Though current DHNs are centred around CHP, future DHNs are likely to look significantly different, with a greater focus on variable renewables [11]. Ref. [17] explores strategies by which to transform the heating sector to 100% renewable energy. There are several challenges that can hinder this transformation and district heating in itself needs to evolve into low temperature networks with low energy buildings and integrate into smart energy systems [18].

Another widely used component in DHN is the heat pump. This technology utilises electricity to power a refrigeration cycle that harvests low grade heat. The performance of a heat pump

is measured by the coefficient of performance (COP), which is the ratio of desired heat output to required electrical input [19]. These values typically range from 2.5-3.5 for DH use but can reach 5 for water-source heat pumps [19]. The two technologies can also be used in conjunction if the waste heat from the CHP is low-grade. The source of heat determines the classification of the heat pump: air, ground or water-source. While air source heat pumps typically have a lower COP than ground/water source, the installation costs are greatly reduced as the need for boreholes and other associated infrastructure is avoided [20].

Thermal energy storage (TES) can potentially add significant flexibility to the DHN. During periods of low heat demand, hot water is stored in accumulators for use when heat demand is high. This can reduce the boiler requirements to meet peak demand, thus improving the efficiency of the DHN [21]. Furthermore, the system can take advantage of aspects such as low electricity prices at night to power heat pumps, or benefit from higher wind energy production, typically at night [21]. This flexibility leads to lower fuel usage and thus lower CO₂ emissions. One study found that CO₂ emissions were reduced by 54% with the integration of TES [4].

From the literature, it appears that DH is a promising means to supply heat demand in the UK and can be implemented with the current state of urban systems. An efficient DHN may include one or more CHP units, heat pumps, TES and boilers for peak heating. This network can then be formulated as a MILP to be optimised in order to find the most favourable emissions mode of operation, e.g. to maximise profit or minimise CO₂ [22].

In terms of the integration of EV charging and district heating, the current literature is focused on micro-scale systems, where a household micro combined heat and power (mCHP) unit is used as a potential source of electricity for EV charging. It has been shown that there is potential for system integration in a small-scale model, leading to a feasible system with annual revenue of \$200-300 per year per EV driver [23]. A larger system may take further advantage of this opportunity through economies of scale and the use of optimisation, especially to deliver electricity at times of peak price [24].

As shown by the literature, there are cases in which there is a mismatch between residential electricity consumption and supply from CHP production [23]. While most of the power is produced during the night, when heating is mainly used, electricity is primarily consumed throughout the day. One possible way to reduce this mismatch is to use EVs, which mainly charge at night, to make up for this surplus of electric power [23].

Furthermore, when considering a large-scale system of 50,000 EVs acting as 'portable electricity storages' coupled to CHP units, it has been shown that operational cost improvements are seen by discharging EVs during peak time and charging them during off-peak periods [25]. However, one possible limitation that must be taken into account is the fact that CHP power production varies by season (much higher during the winter, when more heat is demanded), while the EV charging demand is not likely to change much throughout the year [23]. Therefore, it is also critical to consider an urban consumer charging behaviour when simulating such systems.

One of the major constraints in integrating power co-generation and EV systems are the high investment costs, especially at a small-scale level, as it may lead to long payback periods (close to 20 years for an mCHP system) [24]. Possible ways to decrease this cost include load sharing approaches between residential and commercial buildings and the introduction of district cooling, as this adds on an additional source of revenue [24]. Ref. [26] also mentions that through the introduction of an Energy Service Company it is possible to obtain cheaper natural gas and electricity prices and to remove the barrier of high investment costs, leading to higher economic incentives to adopt the technology.

There are also technical challenges with EV adoption due to grid integration that lead to higher installation expenses [27]. As a result, governments pursue simpler ways to integrate EV demand with local sources of electricity, such as decentralised CHP schemes [27].

In addition to decreasing carbon dioxide emissions and reducing costs by up to 60% (in combination with an mCHP system) [24], electric vehicles can be seen as a good way to increase demand flexibility by storing energy produced in periods of low demand [28]. However, it is important to acknowledge that for a large-scale system, a high number of vehicles may be necessary to reach a significant difference in electricity demand, since car batteries require little power compared to what is produced by a power plant [28].

Ref. [23] show that in absence of any additional energy storage system, it is highly important to match the supply of electricity for EV charging with its demand, since both will vary with time. In addition, when designing such a system it is important to take into account whether the CHP unit is set such as to fulfil heat or electricity demand as they may lead to very different operational profiles. Lastly, it has been shown that the effect of EV and CHP integration can be seen from a financial perspective, but also from a CO₂ minimisation standpoint [24]. This is something important to account for when comparing different objectives in a multi-criteria assessment.

In order to simulate the daily operation of a system that integrates EVs into a DH scheme, data on EV electricity demand with intra-day temporal resolution is also required. But without real data available, simulation tools appear as an attractive option as they can generate synthetic and realistic data for a range of different scenarios. One possible method to generate this data is through an agent-based modelling (ABM) approach [29]. With this, the electricity demand for EV charging can be estimated in a given region considering different driver behaviour scenarios. The model presented by Ref. [30] generates EV charging demand profiles considering not only technical factors such as type of vehicles and charging infrastructure but also geographical and socio-demographic factors that influence the spatial and temporal characteristic of this demand. In this way, agent's daily activities will influence the transport and energy demand and therefore its charging requirements at different times and locations in a particular urban area.

While previous studies have focused on the integration between district heating and EV charging, this paper aims to address this research gap by optimising an existing large-scale system, considering a variety of different energy centre configurations, using both actual as well as ABM generated data.

Furthermore, the design of district heating networks has been analysed in the literature using different optimisation techniques such as mixed integer linear programming (MILP) [22, 31, 32]. The time steps used for the simulations vary greatly in the literature, with Ref. [33], using 'short' intervals of 3 hours throughout the year, compared to 2 time slots per day for four seasons (8 time situations) used by Ref. [32]. Therefore, this paper addresses another research gap by utilising hourly inputs over the period of a year. The results of this study provide an increased level of granularity that allows for a more comprehensive understanding of the behaviour of integrated district heating systems. The one-hour resolution considered in this work allows the incorporation of dynamic pricing signals, and it captures the dynamics of EV charging behaviour compared to the operation of the CHP.

Both the scope and the methodology used in this study address gaps in the existing research and therefore enable a more holistic, as well as detailed, analysis of the integration of electric vehicle charging and district heating networks within a large urban setting.

3. Methods

This section outlines the key mathematical formulations used to describe a DHN system, which can then be formulated as a mixed integer linear program (MILP). As shown in Figure 1, the ABM is used in order to estimate the EV electricity demand, which serves as one of the inputs to the optimisation model, implemented using the modelling tool GAMS [34]. GAMS stands for General Algebraic Modelling System and is specifically used for solving linear, non-linear and mixed-linear optimisation problems.

The key outputs produced are annual profit, CO₂ emissions and the hourly operation of the DHN. It can be run to either maximise profit or minimise CO₂ emissions. The simulation provided the operation over a year.

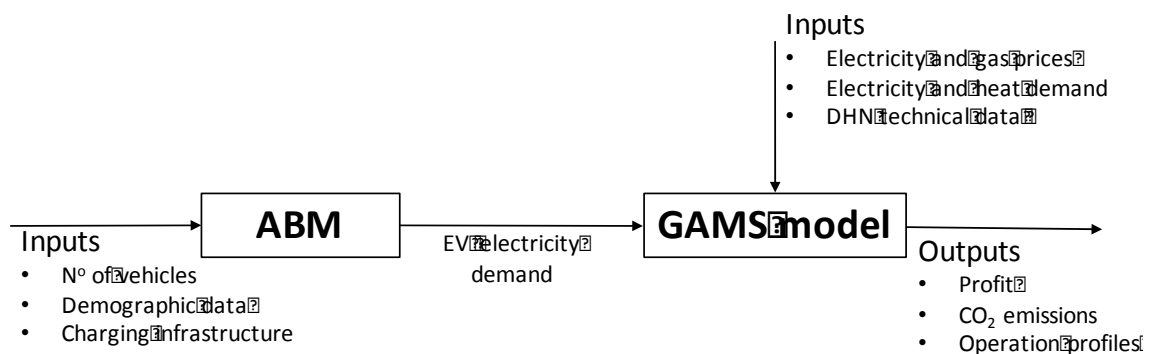


Figure 1: Schematic of ABM and GAMS model interaction.

3.1 Mixed integer linear programming methodology

A general system was modelled to include common units that may be part of a DHN, such as a boiler, CHP units, a heat pump and a thermal energy storage, which could be turned off if not part of the system being studied. The model takes the interactions between multiple stakeholders within the DHN system into account, such as consumer heat demand, internal electricity demand, as well as a potential waste heat recovery system that demands electricity and sells waste heat to the DHN operator. Finally, electricity demand from EV stations are added in the system to be optimized. Figure 2 schematizes the potential interactions within the modelled DHN system.

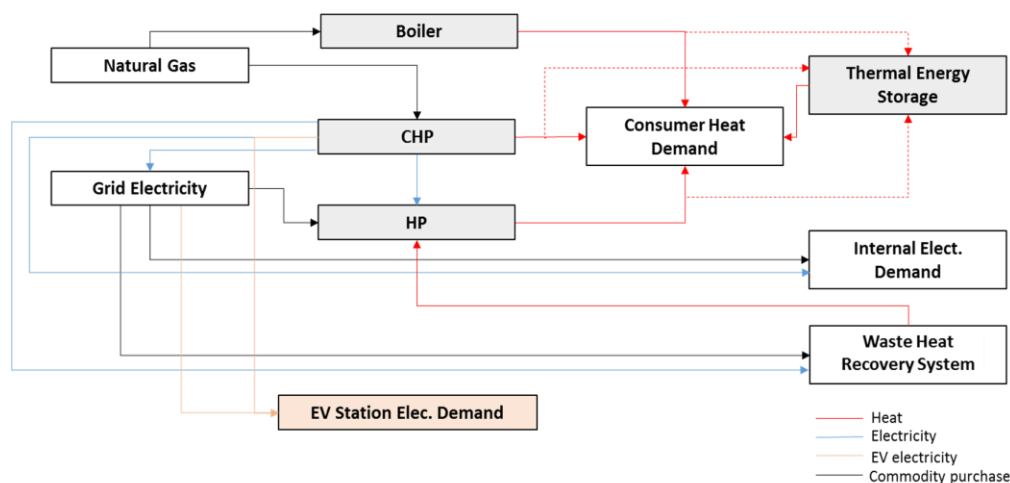


Figure 2: Detailed system schematic including proposed EV integration

The main equations used in this model are outlined below.

- Heat balance:

Equation 1 states that the total heat production must always be able to fulfil the total heat demand.

$$\sum_i Q_t^i \geq D_t \quad (1)$$

- Electricity balance:

Equation 2 states that the sum of electricity imported from the grid and produced by the DHN must always match the sum of that sold to the grid/waste heat recovery system (WHRS)/EV charging as well as the amount consumed by the HP and the DHN internal demand. The HP and DHN internal demand are integral to the operation of the DHN and therefore the grid is used to satisfy this requirement when the electricity from the CHP units is insufficient. The same does not apply for the other terms on the left-hand side of Equation 2 as electricity is only supplied to these destinations by the CHP units; the EV charging station and WHRS determine autonomously how to source any extra electricity requirement they may have, thus these requirements are not part of the DHN electricity balance. Equation 3 shows all possible destinations of the CHP-produced electricity.

$$E_t^{CHP \rightarrow grid} + E_t^{CHP \rightarrow EV} + E_t^{CHP \rightarrow WHRS} + E_t^{HP} + E_t^{int} = E_t^{grid \rightarrow HP} + E_t^{grid \rightarrow int} + E_t^{CHP} \quad (2)$$

$$E_t^{CHP} = E_t^{CHP \rightarrow grid} + E_t^{CHP \rightarrow EV} + E_t^{CHP \rightarrow WHRS} + E_t^{CHP \rightarrow HP} + E_t^{CHP \rightarrow int} \quad (3)$$

- Profit

The profit (Equation 6) is calculated at each time interval as the sum of revenues (Equation 4) from heat and electricity less the sum of fuel and electricity costs (Equation 5):

$$R_t = D_t p^{heat} + E_t^{CHP \rightarrow grid} p_t^{sell, grid} + E_t^{CHP \rightarrow EV} p_t^{sell, EV} + E_t^{CHP \rightarrow WHRS} p_t^{sell, WHRS} \quad (4)$$

$$C_t = (F_t^{CHP} + F_t^B) p_t^{ng} + (E_t^{grid \rightarrow HP} + E_t^{grid \rightarrow int}) p_t^{buy, grid} \quad (5)$$

$$Pr_t = R_t - C_t \quad (6)$$

where, $F_t^{CHP} = \sum_{i=CHP1, CHP2} \left(a_i \frac{Q_t^i}{Q_{i, max}} + b_i \right)$ and $F_t^B = \frac{Q_t^{boiler}}{\eta_{boiler}}$.

The price of heat differs for commercial and residential consumers but is displayed above as a single parameter.

Equation 7 shows the objective function for the profit maximising strategy. This is the summation of the profit over the year, which is maximised.

$$Z = \sum_t Pr_t \quad (7)$$

- Carbon emissions:

The method used for the allocation of CHP fuel use towards distinct heat and electricity production is the DUKES '1/3:2/3' method [35]. This method assumes that twice as many units of fuel are required to produce a unit of electricity than that for a unit of heat. It has been selected as it is the method used under the UK Climate Change Agreements (CCAs) [36]. The emissions of the DHN are attributed to the natural gas consumption of the CHP units and boilers. This is offset by the CHP-produced electricity sold to external parties. Equation 8 states the calculation for determining the CO₂ emissions.

$$CO2_t^{DHN} = (F_t^{CHP} + F_t^B)CF^{NG} + (E_t^{grid \rightarrow HP} + E_t^{grid \rightarrow int})CF_t^{grid} - 1.5CF^{NG}(E_t^{CHP \rightarrow grid} + E_t^{CHP \rightarrow EV} + E_t^{CHP \rightarrow WHRS}) \quad (8)$$

The factor of 1.5 was calculated using the 1/3:2/3 method.

The annual emissions are given by Equation 9:

$$CO2^{DHN} = \sum_t CO2_t^{DHN} \quad (9)$$

The objective function for CO₂ minimisation is given by Equation 10:

$$Z = \sum_t CO2_t^{DHN} \quad (10)$$

In addition, the optimisation model had two main constraints:

- Heat demand constraint: This requires the system to only supply as much heat as is demanded. In other words, if this constraint is applied then the system cannot reject any heat. Mathematically, this constraint would turn the heat balance (Equation 1) into an equality.

It may be desirable to reject heat in instances when the electricity income from the combined heat and power production still leads to profit, and therefore the unconstrained scenario is also important to investigate.

- Noise restriction: Due to constraints limiting the decibel level of noise emissions at night, it was assumed that the CHP units would have to be turned off between 22:00 and 07:00.

3.2 Agent-based modelling methodology

Agent-based modelling (ABM) was used to simulate a potential energy demand for EV charging in a given region, serving as an input for the optimisation model.

However, it is difficult to model the spatial and temporal electricity demand as this must take into account the driving and charging behaviour, which are influenced by drivers' daily activities. The system modelled was based on the ABM approach used by Bustos-Turu et. al to simulate EV demand flexibility in an urban scenario [30, 37]. In this case, the model is based on a range of variables, such as the type of vehicle, access to charging infrastructure, agent's activity schedule (including the probability of departure for a certain activity), etc.

Each vehicle is considered as an agent that is moving around the city in order to complete its daily activities. Vehicles are able to charge either at home or near their destination throughout the day, if they have access to a charging point.

The main assumptions regarding this model are:

- Vehicles within Middle Super Output Areas (MSOAs) that are a radius of 2-3 km away from a centre point are considered in the model to be the group of potential customers.
- The choice of where to charge is based solely on the vehicle's battery level and on the access to charging infrastructure. While parked at home or at work, drivers may leave their vehicles charging (on-schedule charging) if they have a charging point available. The model also assumes that during a journey, if the battery level falls below 30% the driver will look for the nearest public charging point and charge their battery up to 80% (off-schedule charging).
- Three types of vehicles were considered: mini, small and medium with specific market shares based on the work of Bustos-Turu et. al [30].
- Although residential charging is usually done using 3.6 kW charging points, the model assumes that all charging points (whether residential or commercial) are fast charging points (50.0 kW). It was assumed that most new urban charging infrastructure would be comprised of fast charging. In addition, data shows that most of the new charging points being installed in London are rapid charging points [38].
- Two types of users were considered; residential and commercial users. Residential users are agents who use their vehicles to go to their work and daily activities, while commercial users are agents who use their vehicles throughout the day for their business activities, such as delivery services vehicles or taxis.
- Two EV adoption levels were assumed for residential and commercial users, where the percentage of electric vehicles is either 10% or 30% of the total vehicle fleet.

In the case of residential users:

- Residential agents have been divided into two groups; workers and non-workers. Workers make up on average 61.8% of agents, while non-workers make up the rest with the main differences between the two groups being their activity profiles, following the probabilities from Ref. [30].

In the case of commercial users:

- All commercial agents are workers who have been assigned to travel between randomly selected commercial destinations in the borough. The larger the commercial floor space, the higher the probability of a commercial driver selecting that destination.

4. Results

In order to investigate the effects of potential EV integration into a DHN system using real-world model inputs, the Borough of Islington in London was used as an example scenario where EV integration could be applied into its existing DHN system. Therefore, presented results have values that would be specific to the Borough of Islington, however they generate insights that are applicable and discussed in the context of a general EV-DHN integration project.

Since 2012, the Borough of Islington has a district heating network that serves 850 homes and two leisure centres, called the Bunhill Heat and Power network [39]. Bunhill I is the current energy centre where a 2.4 MWe natural gas CHP engine (CHP 1) is used to produce heat and electricity that is supplied to the council [39]. This has led to reductions of around 10% in the heating bills for consumers benefited by the scheme, in addition to a reduction of up to 60% in CO₂ emissions [39, 40]. There is also a 115 m³ thermal store, which may be used to store heat for times of known high heat demand [39].

A new energy centre (Bunhill II) is being built to supply heat to at least 454 additional homes, a school and a nursery as an extension to the existing DHN [39]. In addition to an extra CHP unit (CHP 2), Bunhill II will have a heat pump (HP) that uses electricity supplied by CHP 2 to produce heat. This is an air-source heat pump that can take heat from the 20-30°C London

Underground Limited (LUL) ventilation air and use it to efficiently heat up water to around 80°C [40]. Both energy centres produce electricity that is used internally by the plants and any excess electricity can be sold to the grid. In addition, Bunhill II will also sell part of the excess electricity to LUL, which is able to pay a higher price than the grid, as part of a partnership between the council, London Underground Limited and UK Power Networks [39].

Currently, the excess electricity produced by Bunhill I is sold to the grid at market price (85% of average grid electricity buying price). With the addition of Bunhill II, more electricity may be produced in excess, which may serve as an additional source of revenue to the council. In line with the council's strategy to invest in electric vehicle infrastructure [41], one possible way to increase the availability of cheaper electricity for EV charging would be to sell the excess electricity produced by the energy centres to EV charging stations.

The following Islington-specific inputs were utilised for the integrated model:

- Gas prices: Distinct gas prices were used for the winter (December to February), summer (June to August) and shoulder months (March to May and September to November), based on previous studies [42], as shown in Table 1.
- Electricity prices: Operators are able to negotiate different pricing schemes to buy electricity from the grid. In this study, an hourly tariff system was used based on data from UK Power Networks [43, 44]. In this case, the rate of electricity varies for each hour of a weekday and weekend day. The price at which electricity is sold back to the grid was set to 85% of the buying price. The average price of electricity sold by the grid was found to be 94.1 £/MWh, and the average price at which the grid buys back electricity was 80.0 £/MWh.
- Heat demand: This was estimated based on aggregate data provided by the Islington Council [45 - 47], with different hourly values for each day of a year.
- Electricity demand: To obtain the EV electricity demand in Islington, agent-based modelling was used to model EV owners as agents and obtain their charging profiles.
- Carbon factors: Hourly carbon factors were used for the grid electricity. These are weighted averages derived using electricity production data multiplied with average carbon factors of each production source. A static value of 0.185 kgCO₂/kWh was used for natural gas, both cases based on previous work in this area [45 - 47].
- EV data: Using the information provided by the MSOA Atlas [48], and assuming an EV percentage adoption, the EV ownership is estimated in different areas of London.

Table 1: Gas prices (£/MWh).

Season	Gas price (£/MWh)
Winter	27.5
Shoulder	25.0
Summer	22.5

In the current configuration of the Islington DHN, London Underground Limited (LUL) is modelled as a waste heat recovery system. The CHP-produced electricity is used to satisfy internal demands and is sold to LUL preferentially. It is also used to power the HP, but these demands are not sufficient to consume all the generated electricity. As described in the previous paragraph, the additional electricity is sold to the grid for an average price of 80.0 £/MWh (grid buying price). However, it could be supplied to potential EV charging stations instead. Given that an EV charging station would have to buy electricity from the grid for an average price of 94.1 £/MWh (grid selling price), as long as the DHN sells electricity for a lower price, it can be assumed that the charging station owner would give preference to the DHN. Thus, by charging a price that is higher than the grid buying price and lower than the grid selling price for the DHN electricity, both the DHN operator and charging station owner would

benefit, which is where the motivation for the system integration arises. The potential integrated system is shown in Figure 3.

The following section analyses the effect of the EV charging integration on system operation for various scenarios. The study focuses on two distinct clients for the EV charging station: residential users and a commercial fleet, both studied for EV adoption levels of 10% and 30%.

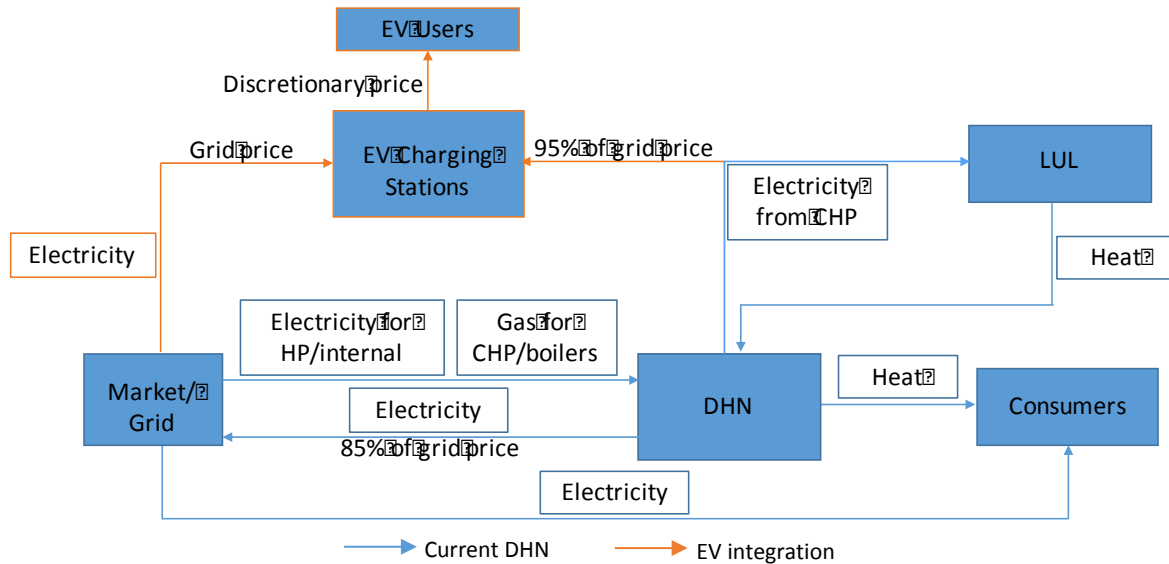


Figure 3: Schematic of potential integration between DHN and charging stations.

The ABM was used to simulate the EV charging demand for this proposed charging station for two distinct clienteles; residential users and a commercial fleet. There were two levels of adoption considered for residential users; 10% and 30% adoption of EV. In the commercial simulations, the number of EV vehicles was adjusted to match the peak electricity demand for the two residential adoption levels, so the different scenarios could be comparable. For simplicity, these are referred to as 10% and 30% adoption for both residential users and the commercial fleet.

It is also important to note that the optimisation model was run to maximise profit without the heat demand constraint while the noise restriction constraint was activated (described in Section 3).

The results for the two client types were superimposed on the CHP electricity production to better understand the relationship between supply and demand, as shown in Figure 4a and Figure 4b. Only the results for a typical weekday have been shown as the demand profile for weekends provides no additional insight into the operation of the system.

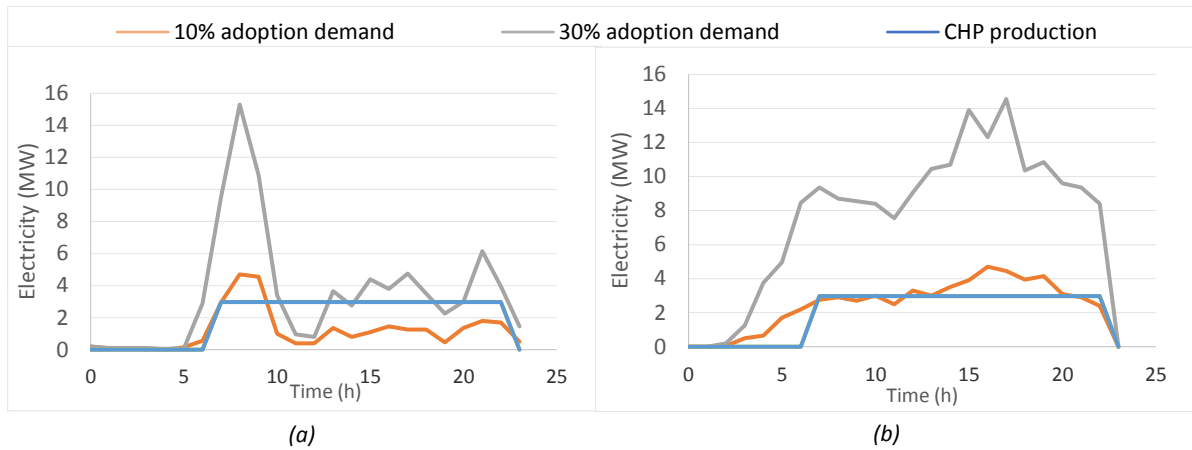


Figure 4: EV charging demand and CHP electricity supply for: a) residential users, and b) commercial users.

In Figure 4a it can be seen that there is a large peak in demand between 07:00 and 09:00. This makes sense, as this is the time when most workers will use their cars to reach their work, or other activities, and will then park and charge their EV. The peak in demand is seen at 08:00, when the electricity demands for 10% and 30% adoption rates reach 4.7 MW and 15.3 MW, or the equivalent of 94 and 206 vehicles respectively. This demand goes down to as low as 0.4 MW at 11:00, when most cars that are parked have finished charging. Demand goes back up in the afternoon, most likely due to agents who are travelling for their daily activities and it reaches another peak between 20:00 and 22:00, which is likely when most workers have already reached home and plugged in their vehicles.

In the case of commercial users however, the demand profile is significantly different. As shown in Figure 4b, the demand profile between 07:00 and 22:00 is much more stable than in the case of the residential users, where peaks in demand occur in the morning and evening. The demand does peak between 15:00 and 17:00, but is still appreciably high throughout the rest of the weekday for both the 10% and 30% adoption rates. The fact that the demand for commercial users is more stable makes sense intuitively since commercial users would use their vehicle throughout the day, unlike residential users who only use their vehicles to go to and from their daily activities and work. Not only does the shape of the demand change, but also the magnitude. Figure 4b shows that demand for 10% adoption is already high enough to cover almost all the electricity produced by the CHP throughout a weekday and the 30% adoption demand is always higher than what is produced by the CHP units, meaning that no electricity would be available to be sold to the grid.

Figure 5a and Figure 5b also show the amount of electricity produced by the CHP units, which is constant between 07:00 and 22:00 in both winter and summer. The CHP units have a maximum cumulated power production capacity of 3.0 MW, which could supply electricity to around 59 cars charging at the same time. However, a small proportion of this electricity is used to supply the internal electricity demand, the HP and the LUL electricity demand, thus this number falls to a maximum capacity of around 48 cars. As a result, at certain times in the day, the CHP unit does not produce enough electricity to satisfy the entire EV demand. However, at other times, such as between 10:00 and 12:00 for the 10% residential adoption scenario, the CHP is still producing more electricity than is demanded by EV users. This poses a challenge since the demand is not constant throughout the day and therefore it might not be worth investing in the infrastructure to supply electricity to all cars during the peak time, when demand is low during the rest of the day.

Having obtained the EV electricity data from the agent-based model, this was then used as an input to optimise the integrated system for the cases of residential and commercial users. The simulations provided the operation of the DHN over a year; the most interesting results are seen for summer and winter. The operations and contrasts between these two seasons will form the focus of the analysis.

Figure 5a shows the effect of a 10% adoption level for residential users on the DHN and Figure 5b shows the effect of a 30% residential adoption level. It is important to note that the charging demand between 22:00 and 07:00 cannot be met by the DHN as the CHP is turned off during these hours to comply with the noise restrictions.

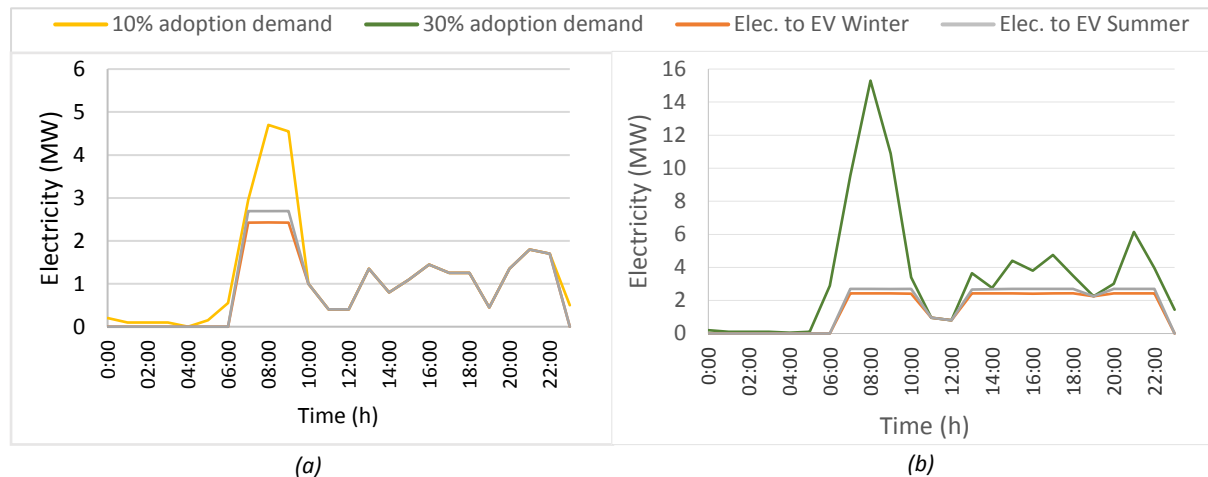


Figure 5: ABM integration for: (a) 10% and (b) 30% residential adoption, respectively.

The figure representing for a typical winter weekday, Figure 5a, shows that the electricity sent for EV charging is not maximised at the time of peak demand (around 08:00). This suggests that there are more profitable ways to utilise this electricity, which can be explained through Figure 6a. During the winter, heat demand is at its highest, with the peak demand between 07:00 and 09:00. Electricity is used to power the HP so as to meet this high heat demand and simultaneously generate higher profits, given the high efficiency of the HP as well as the RHI. This makes it a better alternative to supplying EV charging. Electricity is always preferentially sold to LUL, as the selling price is equal to that of buying from the grid, and thus is greater than the selling price to EV charging. In this case study, the amount that can be sold to LUL is restricted to approximately 0.16 MWh and it can be seen that this constraint is always active during CHP operation since it is the most profitable destination for the CHP-produced electricity. It is also preferable to provide the electricity for the plant's internal demand from the CHP units rather than buy from the grid, which explains the constant supply throughout CHP operation hours. The alternative with the highest opportunity cost is the grid; since it has the lowest selling price it is avoided whenever possible. Electricity is only sold to the grid when all the alternatives are already at their maximum capacities.

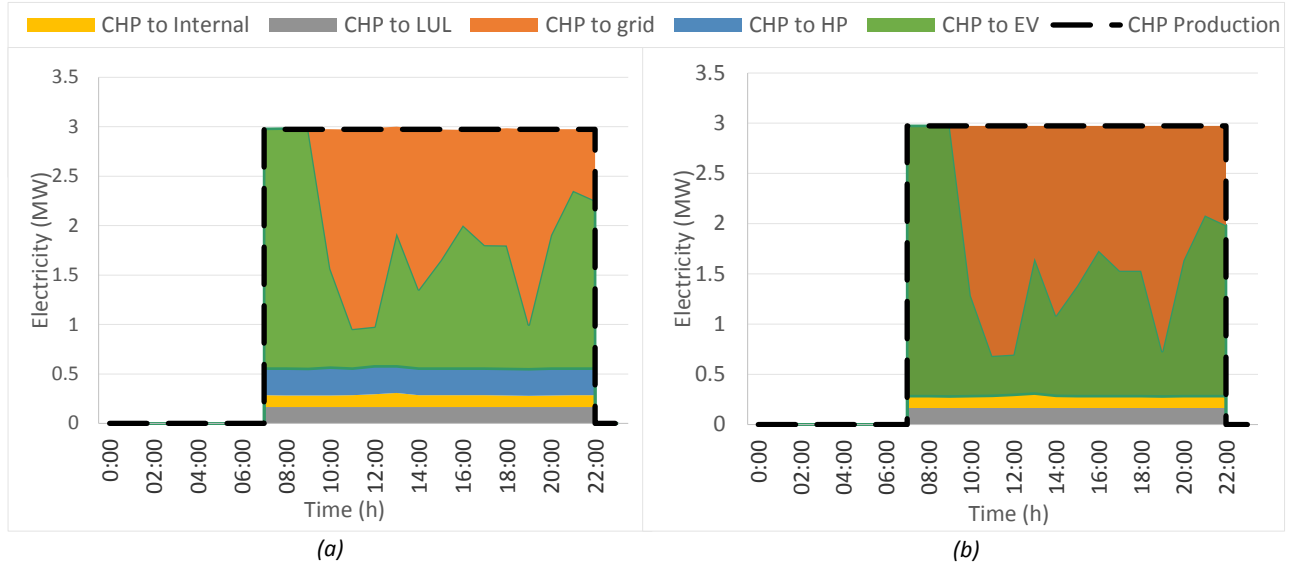


Figure 6: Destinations of DHN electricity with 10% residential EV integration for: a) winter weekday, and b) summer weekday.

Similarly to the winter weekday (Figure 6a), on a summer weekday (Figure 6b) the preference is still given to LUL and the internal demand. However, more electricity is provided for EV charging, thus satisfying a higher proportion of the peak demand relative to a winter weekday. The heat demand is significantly lower for the summer months which results in a lower price for heat. Therefore, supplying electricity for EV charging rather than to the HP is more financially favourable.

The same trends are observed for the case of 30% adoption, albeit with higher quantities (4.8%) of electricity sold to EV, replacing electricity sold to the grid.

The results from the 10% adoption case for the commercial fleet are largely similar to those from the 30% adoption case since the demand is almost consistently beyond the capacity of the DHN. Therefore, the increase in demand from 10% to 30% has a limited impact on the DHN operation and profit. Figure 7 represents the 10% adoption case, from which it can be inferred that there is little scope to alter operations.

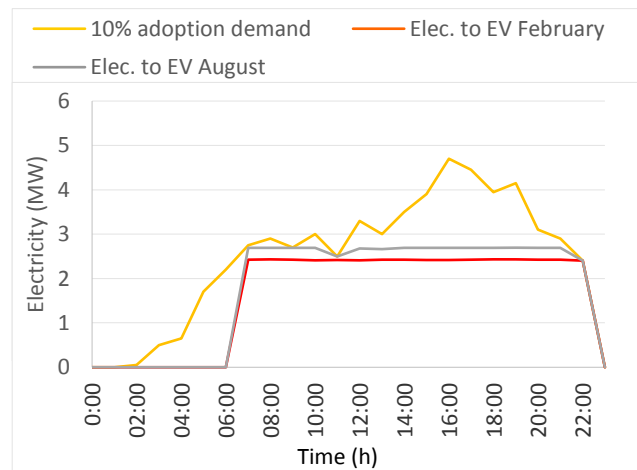


Figure 7: 10% weekday commercial integration.

Similarly, for the commercial fleet the hierarchy of preference for the destinations of CHP-produced electricity remains the same as that seen for the residential cases. Figure 8a and

Figure 8b demonstrate this; in winter, when higher heat demand results in higher heat prices, the HP is preferred to EV charging, whereas the opposite is true in summer.

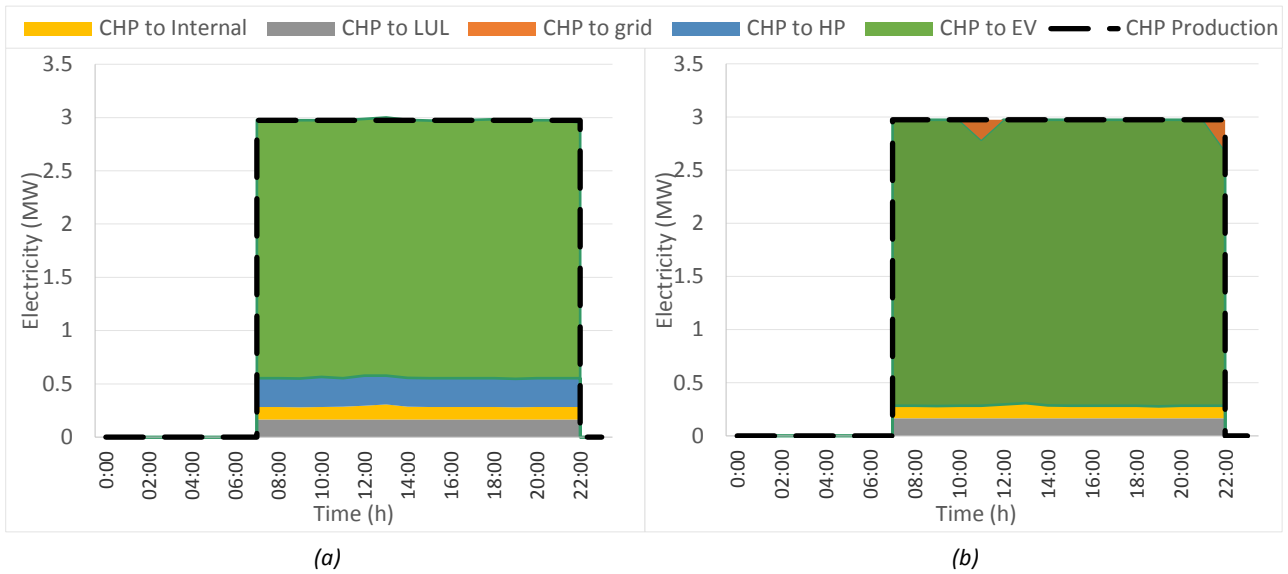


Figure 8: Destinations of DHN electricity with 10% commercial EV integration for: a) winter weekday, and b) summer weekday.

As can be seen from Figure 8a and Figure 8b, there is effectively no electricity sold to the grid, suggesting that the system is incapable of accommodating any further increases in demand.

Since the results have focused on electricity profiles, the impact of the TES unit is not abundantly clear. However, it was found to improve the flexibility of the DHN and alleviate the need to “dump” heat during times when electricity demand peaked but the heat demand was relatively lower. Without the TES, this additional heat produced by the CHP would have been wasted. The additional flexibility provided by the TES increased the annual profit by approximately 18% and decreased CO₂ emissions by approximately 4%.

Figure 9 summarises the results of the optimisation. As shown, the 30% adoption level for commercial vehicles performs best in terms of profit and emissions. In this case, the profit increases by 11.6% and emissions decrease by 0.5% compared to the system without EV integration (Business as Usual, BaU), as detailed in Table 2. The emissions are approximately constant as the operation of the DHN under the EV load differs only in the summer months, where both CHP units are run at capacity. The emissions from the increased fuel consumption are offset by the extra electricity production.

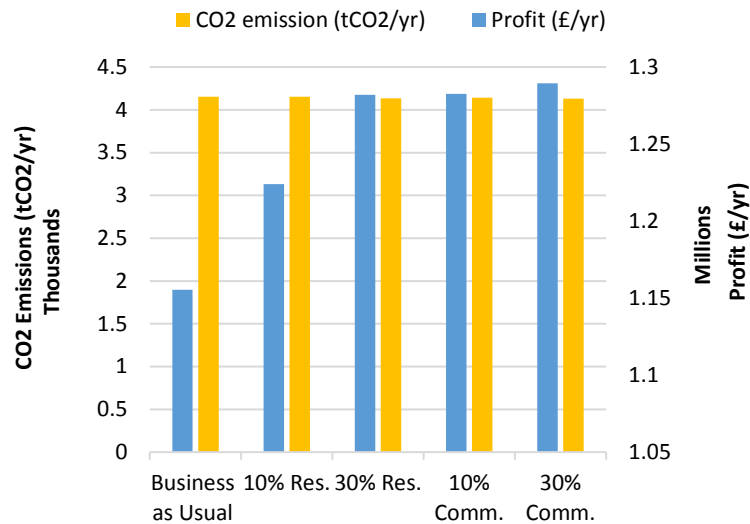


Figure 9: Effect of integrating EV charging for commercial and residential users

Table 2: Summary of optimisation results.

Optimisation results	10% residential	30% residential	10% commercial	30% commercial
Profit (Million £/yr)	1.22	1.28	1.28	1.29
% increase in profit vs. BaU	5.9%	11.0%	11.0%	11.6%
CO ₂ emissions (ktCO ₂ /yr)	4.15	4.14	4.14	4.13
% decrease in CO ₂ emissions vs. BaU	0.03%	0.41%	0.29%	0.52%

The commercial scenarios result in the highest profits, as the demand profile is consistently high throughout the day. Higher demand results in increased profits as electricity that would otherwise be sold to the grid is instead sold to the charging station at a higher price. However, the potential profit is not unlimited as the DHN ability to produce electricity is limited by the capacity of the system. This is highlighted by the relatively small profit increase from 10 to 30% commercial adoption – the DHN is saturated with demand and no further electricity can be supplied for EV charging as shown by Figure 10.

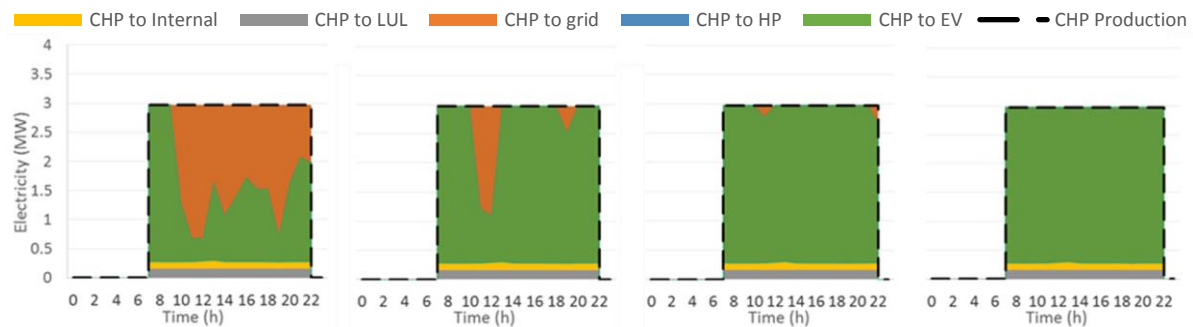


Figure 10: Destinations of CHP-produced electricity for EV integration in summer for 10% residential adoption, 30% residential adoption, 10% commercial adoption, 30% commercial adoption (from left to right).

5. Conclusion

By incorporating EV electricity demand into the current DHN in Islington, a more beneficial, financial and environmental, scenario would be obtained for the DHN and the EV charging station. Electricity demand profiles for 10% and 30% residential adoption levels were generated using an agent-based model. Such profiles were also generated for the equivalent number of electric vehicles of a commercial fleet. It was found that the CHP units at Islington would have the capacity to charge 48 cars at a given time (using 50 kW rapid charging). Therefore, the CHP units alone would be insufficient to completely satisfy charging demand throughout the day.

The highest potential profit was seen for the commercial fleet equivalent to 30% residential adoption. The profit would be approximately £1.29M (52% profit margin), and only £6,000 higher than the 10% equivalent commercial fleet. This suggests that the electricity production would be saturated, and further increases in demand would require the installation of additional generation capacity. The 10% equivalent commercial fleet would be considered the best scenario to conduct further analysis on as it is a more realistic adoption level over the coming years and the consistently high demand from a commercial fleet is more profitable for the system. The improvement in profit over the business as usual case would be 11% and the CO₂ emissions would remain effectively constant. Greater quantities of electricity sold to external parties would offset the system's emissions, thus compensating for the emissions arising from greater CHP usage.

The analysis reveals that the system should be run without a restriction on heat rejection, following the profit maximisation objective function, and that the integration of electric vehicle charging can improve profit. The ideal client for an energy service company operating this system would be a commercial fleet, such as the Islington council vehicles. This work lays the foundation for further development of this proposed solution, which would include consideration of the capital costs of private wires, License Lite schemes [49], as well as the geographical locations of existing/upcoming EV charging stations.

The same modelling approach can be applied to any DHN with a similar configuration and the conclusions that can be derived from the results provide a concrete foundation for further investigation into the potential system integration.

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