Heat pumps for domestic heating: A techno-economic exploration of comparative advantages of individual scale versus district level

Thesis submitted for the degree of Doctor of Philosophy in

Energy and the Built Environment

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March 2022

Declaration

I, Zhikun Wang, confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis.

Zhikun Wang

Acknowledgements

I always feel privileged to have the opportunity to conduct this research guided by my three academic supervisors, Prof. Bob Lowe, Dr. Jenny Crawley, and Dr. Francis Li. This thesis would not have been possible without their support, encouragement, and insights. My sincere thanks go to my supervisors.

This research was funded by the Engineering and Physical Sciences Research Council (EPSRC) Centre for Doctoral Training in Energy Demand (LoLo), [grant numbers EP/L01517X/1 and EP/H009612/1]. I would like to thank EDF Energy R&D UK Centre Limited for providing smart meter data and financial support, and helpful comments on my research from Marie-Helene Laurent, Benjamin Mousseau and Dominique Bertin.

I would also like to extend my gratitude and appreciation to my LoLo colleagues and friends at University College London for providing a great environment for conducting inspirational research. I would like to thank in particular Dr. Hojung Kim, Polina Zahn, and Arnaud Koehl for their emotional support.

I am grateful for my parents and sister who are always incredibly supportive throughout my PhD, especially during the Covid-19 pandemic.

Abstract

A thorough understanding of heat demand is essential for evaluating strategic options to design, plan, and implement future low-carbon heat technologies. Electric heat pumps and decarbonised electricity have been proposed as promising alternatives that could replace gas heating and contribute to the future low-carbon heat mix. District heating has been transformed over several generations to better use renewable sources rather than fossil fuels to meet heat demand. Both technologies are well developed over the past few decades due to a significant amount of scientific research and industrial experience. However, the markets and supply chains for heat pumps and district heating networks are immature in the UK. There are technical, social, and economic factors that present challenges for their deployment. This research offers insights into energy load profiles and peak demand based on data in various types of British dwellings from the largest smart meter field trial. It quantifies energy consumption in dwellings and the aggregated peak demand under cold weather events. This provides an empirical basis for evaluating potential low-carbon heat technologies to replace the existing prevalent gas-fired domestic heating systems. This research investigates the role of heat pumps and district heating by assessing the topological configurations of heat pumps and district heating networks at different scales through techno-economic modelling, in order to explore their comparative advantages from different perspectives, including technical performance, carbon emissions, and cost-competitiveness. This study demonstrates the economies of scales of heat pumps and district heating, and it highlights the advantages of using heat pumps and district heating to reduce carbon emissions via utilising low-carbon electricity and heat sources that would otherwise be wasted.

Impact statement

This study delivers impact for public benefits and offers advantages to different groups. Within academia, the smart meter data output and modelling results of this study will be made accessible to other researchers. Results from this research could feed into broader research in energy systems by providing an empirical foundation for researchers to understand heat demand better and explore strategies to achieve decarbonisation targets. Further, this study could generate direct benefits for industrial stakeholders, such as building developers, energy and utility suppliers, and heat pumps and district heating manufacturers. It delivers positive impacts on the UK's heating market and its consumers concerning heating options and household utility costs.

This study demonstrates that energy demand diversity can be quantified. It reduces the aggregated peak demand and could contribute to the economies of scale of energy supplies on district scales. It can be applied to quantify demand, design load control mechanisms, regulate cost-effective grid operations, save capital costs, and ensure infrastructure reliability while reducing the risks of over- or under-sizing. This research also explores the comparative advantages to integrate heat pumps in buildings and district heating networks via different topological configurations. These promote potential academic and industrial research in the fields of heat pumps and district heating development and energy market management strategies, to evaluate project investments, design contracts and tariffs, and ensure resilient supply.

Moreover, results from this research could offer insights into the electrification of the heating systems in the UK, with implications for long-term strategic infrastructure planning and policy designing. Policymakers may benefit from this study to legislate policy instruments and incentives to encourage the innovation and deployment of low-carbon, high-efficiency, flexible, and affordable heating measures while boosting local employment and economic growth.

Table of Contents

List of Figures

List of Tables

Heat pumps for domestic heating: A techno-economic exploration of comparative advantages of individual scale versus district level

Chapter 1: Introduction

1.1 Research context

The UK's government has announced a series of ambitious energy and environmental objectives to decouple its economic development from greenhouse gas emissions, with the overall aim of transitioning into a low-carbon economy while improving energy affordability, eliminating fuel poverty, increasing energy efficiency, and reducing dependency on imported fossil fuels. The Climate Change Act (CCC, 2008) introduced a set of statutory five-year carbon budgets to reduce greenhouse gas emissions by 80% by the year 2050, compared to 1990 levels, and to promote the share of renewables in the UK's overall energy mix (DECC, 2010; CCC, 2016). Recent reports suggested that more decisive leadership is required from the government to introduce further targets to achieve Net-Zero greenhouse gas emissions by 2050, to meet the long-term climate change mitigation goals set by the Paris Agreement (CCC, 2019; 2020).

The Committee on Climate Change (CCC) has emphasised that meeting these greenhouse gas emission reduction targets will require intensive growth in low-carbon electricity generation to reduce the carbon intensity of the electricity grid; ultra-low emission vehicles; and the generation of low-carbon heat through heat networks and heat pumps (CCC, 2016). Reducing energy demand, decarbonising the fuel supply, and developing and deploying low-carbon technologies are three key approaches to the achievement of these goals (Chaudry et al., 2015).

However, there is a gap between the UK's ambitious net-zero emissions target and its current heating systems. It is suggested that to achieve the decarbonisation targets, carbon emissions from the building sector will need to be reduced to almost zero (DECC, 2012). Besides, the Carbon Plan

(DECC, 2011) stated that energy efficiency needs to improve dramatically across all sectors, and the energy infrastructure and building stocks require enhancement to balance supply and demand. However, under rapidly changing market conditions, it will be a significant challenge to achieve these targets due to technical, economic, and social barriers. Furthermore, there are considerable political and regulatory uncertainties in implementing and enforcing these policies under the current political circumstances following the UK's referendum to leave the European Union.

Demand for heat makes up the most significant proportion of both annual and peak hourly energy demands in the UK (Connolly, 2017). It is estimated that, on average, domestic natural gas consumption is more than three times higher than domestic electricity consumption (BEIS, 2016a). Heating and hot water for buildings contribute to around 40% of the UK's energy consumption, and over 13% of the UK's carbon emission is associated with the supply of residential space heating and domestic hot water (CCC, 2016). Electricity generation from renewables and high-efficiency, low-carbon heat technologies are expected to play a vital role in meeting the UK's demand for heating, and energy and environmental targets, while bringing health, wellbeing, and economic benefits.

The UK's domestic heating systems have experienced radical transformations over the past half century. Before 1970, solid fuels, oil and direct electric resistive heating were the most common ways to provide space heating and domestic hot water (Hawkes et al., 2011). After that, due to an abundant natural gas supply, expansion of the UK gas grid, and technical developments in gas boilers (Hanmer and Abram, 2017), natural gas has become the principal fuel source for heating systems in the UK (Larminie et al., 1987), and individual gas boilers with hot water tanks became the predominant way to meet domestic heat demand. Over the past three decades, the market share of domestic hot water storage systems has dropped significantly because of the availability of combination boilers that deliver hot water instantaneously and need no storage tanks (Hawkey, 2012).

At present, less than half of UK dwellings have hot water tanks installed, compared to more than 90% in 1990 (DECC, 2016d). Well-developed natural gas networks connect to over 22 million homes, while low-carbon heat technologies contribute to a very small fraction of the UK's current domestic heating supply (Hannon, 2015). By 2014, over 85% of British households had gas boilers (Delta-ee, 2014), and around 1.6 million gas boilers were being installed per year (Nowak et al., 2014). Additionally, oil, liquid petroleum gas and electric heating are commonly used to supply heat for almost four million homes that are not connected to the gas grid (CCC, 2016).

The decarbonisation strategies to reduce the UK's energy dependency on natural gas and greenhouse gas emissions from domestic heating can be classified into three main categories. The first category includes reducing heat demand through building efficiency improvements. Improving the overall performance and energy efficiency of new and existing buildings is considered the most fundamental cost-effective strategy for long-term heat decarbonisation (Connolly et al., 2014; HRE, 2016; BEIS, 2018a). Moreover, improving domestic energy efficiency is also a pivotal approach to tackling fuel poverty and enhancing residents' health and wellbeing (WSBF, 2016).

The second category includes decarbonising fuel supplies, which means decreasing the carbon content of the gas and electricity grids. Re-purposing the gas networks for low-carbon gas has been proposed as a way to continue to use the gas networks, as this may cause less disruption compared to other methods (Northern Gas Networks, 2016). This approach recommends that hydrogen or biogas are injected into the gas networks to reduce their overall carbon content (Policy Connect, 2017). The H21 concept has been proposed as a solution to convert existing gas networks to 100% hydrogen across the north of England, supplying 14% of heat in the UK by 2035 (Northern Gas Networks, 2018). However, there are issues regarding bio-energy supply chains and logistics (Gold and Seuring, 2011), and large scale hydrogen production may rely on carbon capture and storage technologies, with large upfront costs, or on decarbonised electricity via electrolysis (CCC, 2016).

The third category includes employing low-carbon technologies to supply heat with low or zero carbon emissions. A number of alternative technologies have been identified that can replace gas-fired heating systems and contribute to the decarbonisation of the domestic heating sector in the UK, including domestic heat pumps, district heating networks, solar thermal and biomass heating systems.

In recent years, a number of policy instruments and financial incentives have been introduced to improve energy efficiencies in dwellings, promote the installation of low-carbon technologies, and reduce carbon emissions from the heating sector (Ofgem, 2019a), such as the Green Deal, the Renewable Heat Incentive (RHI), Renewable Heat Premium Payment (RHPP), and the Heat Networks Investment Project (HNIP). Also, the government (BEIS, 2020) has proposed changes to the Building Regulations (2019) to improve energy efficiency of new homes and future-proof them for the deployment of low-carbon heating systems, including district heating networks, as well as the integration of heat pumps. However, low-cost gas boilers and well-established gas networks are formidable obstacles to the deployment of low-carbon heat technologies, and the low-carbon heat market and associated regulations remain underdeveloped and immature in the UK (Delta-ee, 2018a).

Heat pumps are known for their high efficiency, as they transfer more heat than the electricity they consume, often by a factor of three or four (Hepbasli and Kalinci, 2009). High efficiency electric heat pumps could play a central role in the UK's future approach to heating, together with the decarbonised electricity grid (CCC, 2016; BEIS, 2018a). Furthermore, heat pumps can be integrated into district heating networks, which may provide opportunities to better utilise waste heat or renewables and offer the potential for additional carbon emissions reduction (Johnston et al., 2005).

District heating is defined as an energy service that transfers heat from heat sources to multiple consumers by circulating steam or hot water. The fundamental idea of modern district heating is to utilise local fuels or heat sources that would otherwise be wasted (Frederiksen and Werner, 2013). Traditionally, district heating consumes fossil fuels to supply steam or high temperature water to areas with high heat demand density (MacKenzie-Kennedy, 1979). Over the last century, district heating technologies have been improving (Lund et al., 2014). State of the art district heating technology can operate at lower temperatures and utilise heat pumps, renewables, and thermal storage efficiently. The Heat Roadmap Europe report (HRE, 2017) suggests that there is the potential for the market share of district heating in the 28 EU countries to reach 30% by 2030, and 50% by 2050.

In contrast to the approach of re-purposing the gas grid, which uses bioenergy or hydrogen for heat, district heating can utilise different types of energy sources, including both conventional and renewable resources, plus waste energy, to supply heat with greater flexibility and efficiency. District heating has been proven to be an economically viable approach to meet heat demand in the UK's high heat density areas that rely on electric heating, also to reduce the consumption of coal and reduce air pollution since the 1970s (Marshall, 1977).

While heat pumps and district heating have been widely deployed in some countries, they are still niche options in the UK. Although the numbers of installed domestic heat pumps and district heating networks have been growing in recent years, before 2015, only about 0.2% of the UK's total heat demand was supplied by electric heat pumps (Hannon, 2015). In 2013, less than 2,000 district heating schemes operated across the UK, and around three-quarters of them were supplying heat to networks with less than a hundred dwellings (DECC and AECOM, 2015). Nevertheless, the number of heat networks has increased intensively in recent years, particularly in small communal schemes, with approximately 17,000 heat networks operating in 2018 (5,500 district heating networks, 11,500 communal heat networks), supplying about 2% of the UK's total heat demand (ADE, 2018).

Among a number of potential alternative ways to meet the domestic heat demand, electric heat pumps are versatile technologies. They can be installed at individual dwellings and used as standalone technologies, as well as integrated into heat networks on different scales according to different topological configurations to provide heat with higher efficiency and flexibility. District heating networks alone do not reduce carbon emissions, and they may increase energy consumption due to distribution heat loss and pumping energy. However, district heating networks offer the potential to improve heat pumps' efficiency and the ability to utilise different local energy sources.

Electric heat pumps can transfer more heat to buildings than the electricity they consume, and when combined with district heating, they can deliver heat to a group of dwellings by utilising renewables or recovering heat from sources that would otherwise be wasted. However, the combination of heat pumps and district heating has very limited applications in the UK. One example is the Bunhill District Heating Network in London, which utilises waste heat from the London Underground to supply heat for local buildings (Ramboll, 2021). There is a need to explore the integration of heat pumps, district heating networks, and local sustainable energy sources.

Owing to the projected growth in renewable electricity generation, it is suggested that electrification of the heating sector could provide energy savings, contribute to reducing energy system costs by improving the overall system efficiencies, and eliminate fossil fuel consumption (Stratego, 2016). Moreover, district heating networks integrated with heat pumps may offer an additional route to the electrification of the heating sector. The CCC (2019) and the Clean Growth Strategy (BEIS, 2017) have identified the priorities for meeting the climate objectives by setting out a series of recommendations to phase out fossil fuel heating in buildings off the gas grid during the 2020s; building and extending heat networks across the country; and investing in the development of low-carbon heat technologies and energy efficiency measures.

It is neither practical nor affordable for the UK to develop and deploy all low-carbon heat technologies to replace current gas-fired heating systems. Indeed, the CCC (2016a) states that ‘the best balance between hydrogen and heat pumps, alongside heat networks, is unknown’. There is a need for research on potential competing heat technologies and detailed analyses of the comparative advantages of deploying heat pumps and district heating in different types of buildings at different scales. Further, the technical performance and costs of installing and operating heat pumps and district heating networks may differ significantly depending on how they are connected and operated. Therebefore, it is important to evaluate the costs, technical performance, and carbon emissions of heat pumps and district heating based on how they are interconnected with buildings. This study explores the application of heat pumps and district heating networks in different topological configurations, quantifies energy consumption and aggregated peak heat demand, and evaluates their carbon emissions from individual buildings to the district level for dwelling in the UK.

1.2 Research questions and aims

This research aims to investigate heat demand in the UK's domestic buildings and explore the economic and environmental trade-offs between potential topological configurations of electric heat pumps integrated with district heating networks. The following overarching research question is proposed:

What are the economic and environmental advantages or disadvantages of utilising heat pumps and district heating networks to meet the domestic heat demand through different topological configurations: individual, district level, both, or neither?

This overarching question will be answered by investigating two subsidiary research questions:

Subsidiary research question 1:

How much heat demand is required for different types of domestic buildings, and how does the peak of the aggregated heat loads change due to diversity and scaling effects at district levels?

Heat demand must be quantified before evaluating potential heating technologies. The UK's housing stock consists of five main types of dwellings: terraced houses, semi-detached houses, flats, detached houses, and bungalows, plus a very small amount of other building types such as temporary dwellings (DECC, 2014a). The first subsidiary research question addresses how much heat demand is required for the five main types of domestic buildings; assesses the heat demand with respect to external temperatures; and measures how the peak of the aggregated heat loads changes when a group of dwellings are connected in one network, due to diversity and scaling effects during different time periods when the number of dwellings increases.

The first subsidiary research question aims to:

- quantify heat demand in the five main types of dwellings in the UK through analysing historical energy consumption data.

- investigate the weather dependence of energy demand in dwellings and quantify the winter peak demand.
- examine heat load profiles and demand diversities in dwellings from individual to district levels and their applications for developing district heating networks

Subsidiary research question 2:

What topological configurations of heat pumps and district heating could be implemented for the UK's dwellings, and what are the economic and environmental advantages or disadvantages of deploying heat pumps in different topological configurations?

The second subsidiary research question evaluates potential topological configurations among dwellings, heat pumps, and district heating networks. It considers different ways to integrate heat pumps with district heating to meet domestic heat demand. This research question assesses heat pump and district heating performance based on different topological configurations, including heat pump efficiencies, fuel consumption, network heat losses, and carbon emissions. This question also investigates the costs to install heat pumps and district heating systems, the economies of scale of district heating networks, and the economic, technical, and environmental trade-offs between different configurations and scales of district heating networks with respect to the number of dwellings.

Possible topological configurations to utilise heat pumps in district heating networks to meet dwellings' heat demand can be categorised into four groups according to how they are interconnected:

1. Individual heat pumps at individual dwellings replacing gas boilers without district heating networks.
2. No heat generating measures at individual houses that are connected to district heating networks, and large scale heat pumps working as

centralised heat generators in the networks that deliver heat to individual houses.

3. Small scale individual heat pumps at individual dwellings working as boosters to raise the water temperature from low temperature district heating networks.

4. A combination of topological configurations 2 and 3, where heat pumps are used in both district heating networks and individual dwellings: large scale centralised heat pumps in district heating networks and small scale individual booster heat pumps in individual dwellings.

This subsidiary research question aims to:

- compare heat demand and fuel consumption for five types of individual dwellings and evaluate topological configurations in which heat pumps can be integrated into district heating networks at different scales.

- assess heat delivered to dwellings and heat loss through transmission and distribution networks based on the trade-offs between different district heating parameters, including pipe features and network temperatures.

- evaluate the costing structures and carbon emissions to meet heat demand in different dwellings at different scales associated with different topological configurations and compare them to the reference case where heat demand is supplied only by individual gas boilers.

- investigate the implication of economies of scale in heat pumps and district heating networks when the size of heat pumps and the number of dwellings that connect to the district heating network increases.

1.3 Structure of this thesis

After introducing the research context and questions in Chapter 1, this thesis is composed of the remaining four chapters. A literature review chapter reviews previous heat pumps and district heating studies and highlights the research gaps and opportunities. Then two analysis chapters to answer the proposed two research questions. Each analysis chapter also has its further literature review subsections focusing on the two subsidiary research questions. This thesis ends with a concluding chapter which summarises and reflects on this research.

Chapter 1: Introduction

The introduction starts with a brief overview of the UK's heating infrastructure and market background, explaining the climate objectives, challenges and the importance of decarbonisation in the heating sector. This chapter outlines the potential options to decarbonise the heating sector. It then discusses the motivation underlying this research, looking at why it is interesting and how heat pumps and district heating networks could contribute to future strategic heat planning and carbon emission reductions. This section also states the research questions and goals of this research, together with a summary of the thesis' structure.

Chapter 2: Literature review

This chapter critically reviews the previous literature in the fields of heat pumps and district heating systems using different methods, focusing on approaches that can reduce carbon emissions from domestic heating. It reviews heat pump and district heating technology assessments, market projections and field trials. Also, the literature review explores the existing research studying recent developments and components of district heating networks. It looks at major district heating concepts and the tendency of future technological advances, as well as examines ways of integrating heat pumps into district heating networks from technical and economic perspectives. The literature review section concludes by justifying the focus of this research, highlighting the existing gaps in the literature, and identifying potential methodological approaches that could address the research questions.

Chapter 3: Analysis of empirical heat demand in British dwellings

This chapter answers the first subsidiary research question, by assessing empirical heat demand in typical types of dwellings in the UK and quantifying the peak heat demand during the coldest time of an unusually cold winter. The contribution of this chapter is to empirically explore heat load profiles and demand diversity in different dwellings, quantifying the annual and hourly peak demand based on smart meter data collected through large field trials. Heat load profiles in different dwellings over different periods are discussed, though analysing smart meter data, as well as looking at the diversity and scaling effects when the number of dwellings increases, from individual dwelling to an aggregated scale. Also, aggregated load profiles from gas boilers are investigated and compared to load profiles from heat pumps. This chapter concludes by discussing the applications of load profiles and demand diversity on sizing district heating systems.

Chapter 4: Techno-economic analysis of topological configurations to utilise heat pumps and district heating networks

Based on the quantification of heat demand in Chapter 3, this chapter addresses the second research question, focusing on ways of meeting heat demand by connecting dwellings, heat pumps and district heating networks, via different topological configurations. This section describes a techno-economic assessment model, in order to assess how heat pumps and district heating operate in different topological configurations. It evaluates the relationship between heat pumps' capacities and their costs, investigates technical trade-offs among different district heating operational conditions, and discusses the economic and environmental advantages or disadvantages of utilising heat pumps in four proposed topological configurations on different scales, compared to a reference case where gas boilers entirely supply heat demand. Uncertainties and sensitivity analyses are conducted to evaluate the relative impact of input parameters and assumptions on modelling results.

Chapter 5 Conclusions

This chapter summarises the key results and arguments from the analysis of domestic heat demand and techno-economic modelling of heat pumps and district heating networks, to answer the research questions proposed by this study. This chapter discusses the weaknesses of the levelised cost method and reflects on the limitations of the modelling approaches. It draws on key insights, emphasising the contribution of this research, together with outlining some ideas for potential further research.

1.4 Novelties of this study

The main originality in this research lies in the analysis of domestic energy load profiles and energy demand diversity based on empirical energy consumption data from the largest smart meter field trial, which covers one of the coldest winters in Britain over the last three decades. In previous studies, there is a lack of empirical investigations regarding the demand diversity effect due to the lack of high-quality and high-resolution actual energy consumption data, and very few studies have investigated domestic heat load profiles or their aggregation. This research offers insights into how heat is consumed in various types of British dwellings and the aggregated peak energy demand under very cold weather conditions. This provides an empirical basis for evaluating potential low-carbon heat technologies to replace the existing prevalent gas-fired domestic heating systems.

The results of heat load profile analysis allow the techno-economic model to capture the diversity effect of aggregated energy demand on different scales, and therefore to provide a foundation for appropriate sizing of different components of district heating systems. In addition to utilising empirical energy load profiles, there are elements of originality regarding the heat pump and district heating techno-economic model:

First, district heating models have been built for some European studies at the national levels, but the heat pumps and district heating market and supply chains are immature in the UK. The generalisability of European studies for the UK is arguable, and it is essential for modelling studies to specify how buildings, heat pumps, and district heating networks are integrated and operated. This model is not built to assess the feasibility of one particular proposed local district heating project, more importantly, this model is used to explore different ways to connect dwellings, heat pumps and district heating networks by comparing the economic and environmental trade-offs among four types of topological configurations with appropriate sizing of heat pump capacities, district heating subsystems, and pipes.

Second, the model includes three different types of fuel prices. Besides a single projected future annual price, this model also considers historical hourly retail electricity spot prices that consumers have paid in the UK and hourly wholesale prices that were traded between over 300 buyers and sellers on Nord Pool's day-ahead market in 2018.

Third, previous studies are limited to focusing on either individual projects or the whole energy system without distinguishing how heat pumps are connected or operated between dwellings and networks. This model studies heat pumps and district heating on five different scales according to the number of dwellings connected and the aggregated after diversity maximum demand. Furthermore, this model uses different pipes for different scales and studies different operational temperatures to evaluate the trade-offs between pipe sizes, operational temperatures, pumping energy, heat loss, and costs among different topological configurations to utilise heat pumps and district heating networks to meet domestic heat demand.

Chapter 2: Literature review

2.1 Introduction

This chapter focuses on previous literature, providing a review of the scientific evidence relating to electric heat pumps and district heating technology development in order to evaluate their potential to decarbonise the domestic heating sector. This chapter critically reviews previously published heat pump field trials and market assessments, and considers the technical development of, and significant breakthroughs in, district heating networks. It synthesises the major concepts of district heating, evaluates the existing research on components of district heating networks, explores possible future technological advances, as well as examines ways of integrating heat pumps into district heating from technical and economic perspectives. It reviews energy models that have been applied to the study of district heating at different scales, from individual buildings to national and multi-national scales. This chapter concludes by highlighting existing research gaps and opportunities, justifying the focus of this research, and outlining methodological approaches that will be used to address the research questions in this thesis.

2.2 Heat pumps

Heat pumps have been widely supported as potentially economical replacements for conventional heating measures, which could improve overall energy system efficiency (Chua et al., 2010). Electric heat pumps with decarbonised electricity can become the key environmentally sustainable way to meet heat demand (BEIS, 2017; IEA, 2017a). Studies from the Heat Roadmap Europe (HRE, 2016) investigated heat sources and demand in a group of European countries and claimed that heat pumps are recommended as the primary future individual heating technology, with small shares for biomass boilers and solar thermal energy.

An electric heat pump is a system in which refrigeration components transfer heat from a colder source to a warmer place (sink), similar to refrigerator systems, but operating in reverse, to provide space heating and hot water (Sauer and Howell, 1983). There are two main types of domestic electric heat pumps based on the sources of heat they extract from: ground source heat pumps and air source heat pumps. The efficiency of a heat pump is primarily dependent on the temperature difference between the heat source and the heat sink, and it can be affected by a number of factors such as heat pump types, local climate conditions and system controls. It is commonly measured by a coefficient of performance (COP) or a seasonal performance factor (SPF), which are the ratios of heat output to electricity input.

Heat pumps could transfer more heat than the electricity they consume, often by a factor of three or four (Hepbasli and Kalinci, 2009). Data from the domestic Renewable Heat Incentive (RHI) deployment revealed that among 29,000 domestic heat pumps installed between April 2014 and March 2019, the average designed SPF of air source heat pumps and ground source heat pumps was 3.2 and 3.8 respectively (BEIS, 2019b). Many examples have shown that appropriately sized electric heat pumps could meet domestic heat demand with high efficiency while significantly reducing carbon emissions from heat (Jenkins et al., 2008; Jenkins et al., 2009; Self et al., 2013).

The Energy Saving Trust (EST) carried out a two-phase heat pump field trial (phase one 2008–2010 with 83 sites, phase two 2010–2013 with 44 sites) in the UK to examine heat pump performance and domestic heating patterns through in situ monitoring and interviews (EST, 2010; 2013). Results also showed that the monitored heat pump COP varied between 1.2 and 3.6, and that ground source heat pumps performed better than air source heat pumps (EST, 2013). However, ground source heat pumps may not be appropriate for all households because not all dwellings have suitable spaces for installing them. Furthermore, the EST field trial results suggested that heat pumps could reduce residents' heating bills, and more than 80% of customers were satisfied with their heat pumps' performance even though many of them were incorrectly installed (Caird et al., 2012).

Having compared the EST heat pumps' performance to the results from heat pump field trials in Germany and Switzerland, Delta-ee (2011) pointed out that the SPFs of the heat pumps in the UK were lower, possibly due to inappropriate sizing, incorrect set-up, and poorly insulated dwellings. Similarly, Bait et al. (2012) studied the performance of a group of ground source heat pumps in British dwellings and found that, on average, heat pumps performed worse in the UK than in continental Europe; they also recommended that the capacity and control of heat pumps need to be better designed to match the buildings' thermal characteristics in the UK. Furthermore, a number of studies showed that heat pumps operate with higher SPFs in newly built, well-insulated buildings with underfloor heating (Hewitt, 2012; Arteconi et al., 2013; McMahon et al., 2018). Nonetheless, Gleeson and Lowe (2013) conducted a meta-analysis of eight European heat pump field trials and emphasised that it is important to have a unified framework and a consistent definition of system boundaries to measure heat pump performance because different heat pump system boundary choices can influence the results considerably.

Lowe et al. (2017) analysed data from 700 heat pumps installed through the Renewable Heat Premium Payment scheme (Ofgem, 2019c) to evaluate domestic heat pumps' performance and costs. They found that energy bills and carbon emissions were reduced at a majority of sites and suggested that heat pumps need to have an SPF higher than 2.5 to be classified as renewable heat sources. This study also found that among a total of 391 sites, more than a third of air source heat pumps and one-fifth of ground source heat pumps performed with an SPF lower than 2.5 (Lowe et al., 2017). Moreover, by using the same sample, Love et al. (2017) investigated the impact of electric heat pump uptake on the national electricity grid through an upscaling method; this study indicated that a heat pump market share of 20% in the UK could lead to an increase of 14% in evening electricity peak demand, but this would not significantly affect the shape of the grid load.

Technical and practical suitability studies conducted by Delta-ee (2018a) found that more than 70% of dwellings, out of 1.3 million dwellings in England and Wales included in the studies, were found to be suitable for installing individual air source heat pumps or ground source heat pumps. In the meantime, heat pumps can enable considerable energy savings in these dwellings, compared with incumbent heating systems (Delta-ee, 2018b). Similar conclusions were found in another analysis of 21 non-domestic heat pumps in the UK. This study showed that a third of studied heat pumps operated with an SPF higher than 3.0 and that 90% of them reduced carbon emissions compared with gas heating (DECC, 2016b). However, this study also admitted that verification of the accuracy of heat metering was lacking, and the sample size was limited.

In the past few years, a substantial amount of research on heat pump market development in the UK has been conducted by the government, energy and environmental consultancy organisations, manufacturers, research institutes and utility companies. There are approximately 11 million heat pumps installed in 21 EU countries, supplying about 130 TWh of heat annually (EHPA, 2019a). In the UK, heat pumps only contribute a very small fraction of total heat demand (Hannon, 2015), and less than 27,000 heat pumps were sold in 2018 (EHPA, 2019b). Furthermore, research pointed out that there are a number of financial and social challenges to the mass deployment of domestic heat pumps (Singh et al., 2010; Fawcett, 2011; Liu et al., 2014).

However, pathways and scenarios studies have frequently suggested that the electric heat pump market will grow intensively in the next three decades (DDPP, 2015; ETI, 2018a; National Grid, 2018). Meanwhile, the Low Carbon Innovation Co-ordination Group (LCICG, 2016) claimed that technological innovations could reduce the cost of heat pumps by up to 31% by 2050. Furthermore, the EU and UK have introduced a range of directives, policies, and financial incentives to promote energy efficiency measures and the deployment of electric heat pumps (Kanellakis et al., 2013; Mallaburn and Eyre, 2014; WSBF, 2016). To meet the Net-Zero target, the UK government set the goal to install 600,000 heat pumps per year by 2028 (HM Government, 2020).

Many modelled decarbonisation pathways commissioned by the UK government specified that electricity could become the dominant way to supply heat, with a considerable decrease in energy demand and extensive growth in bioenergy and heat networks (DECC, 2012; BEIS, 2020). Besides, electric heat pumps are recognised as the primary low-carbon heat technology for buildings that are not connected to gas grids and can substitute for carbon intensive heating technologies such as oil-fired systems (BEIS, 2018a; CCC, 2016b). The strategic framework for low-carbon heat in the UK (DECC, 2012) employed two modelling tools (RESOM and ESME) to assess possible pathways to the decarbonisation of the UK's heating system. It was recognised that the expansion of heat pumps and district heating networks are vital to meet the decarbonisation targets (DECC, 2013b); However, there are technical and financial barriers that stand in the way of radical transformation of heating systems in the short and medium terms.

2.3 District heating networks

District heating is defined as an energy service that transfers heat from heat sources to its consumers, and its fundamental idea is to utilise local heat resources or fuels that would otherwise be wasted (Frederiksen and Werner, 2013). District heating is not a new concept. From a hot water distribution system in 14th Century France (Woods and Overgaard, 2015) to an experimental steam distribution system deployed in the US in 1877 (Turpin, 1966), district heating schemes have been continuing to expand all over the world. District heating with combined heat and power plants has been identified as an economically viable option to supply heat to the UK's high heat demand areas (Marshall, 1977). Originally, the primary duty of a district heating scheme was utilising a centralised thermal source to deliver distributed heat services over 'as large an area as possible containing as many customers as economically viable' (MacKenzie-Kennedy, 1979).

The district heating networks experienced major growth in Europe after the two oil crises during the 1970s, and the technology has been evolving over four generations (Lund et al., 2014). The role of district heating has become more important in order to utilise fluctuating renewable energy generation, increase energy efficiency, and contribute to future sustainable energy systems (Mathiesen et al., 2015; Connolly et al., 2016; Connolly, 2017; Sayegh et al., 2017). Over the past half century, district heating has been evolving into the main approach to reliable heat production, transmission, and utilisation in many countries, and a modern district heating system may supply heat on different scales, from a small community to a whole city (Wiltshire, 2015). A well-designed modern district heating scheme has become a way of recycling heat from power plants which would be wasted, or accessing heat from low grade heat sources or renewables. Therefore, district heating networks have become an effective way to reduce carbon emissions from heat.

Today, there are approximately 80,000 district heating schemes operating in the world, supplying around 3,200 TWh of heat annually, with around half of heat delivered to buildings (Werner, 2017) and half of heat for industrial purposes. Russia, China, and the EU are the three largest consumers, accounting for 85% of the total heat delivered through district heating worldwide (IEA, 2016). Thanks to geographical advantages, which provide abundant geothermal energy, district heating serves over 90% of the heat demand in Iceland through almost 100% recycled heat or renewables (Werner, 2017). However, in the UK, although it is suggested that district heating could supply up to half of the overall heat demand by 2050, the current market share is less than 2% (Euroheat & Power, 2017). A report (HNDU, 2017) revealed that there are around 2,000 district heating schemes supplying to a total of 210,000 British dwellings. An earlier report (DECC, 2013c) pointed out that in 2013, 55% of the current district heating schemes in the UK were operating in London, and nearly three-quarters of the networks were considered small schemes.

Although district heating could bring environmental benefits to the UK's future sustainable development in the long term, Kelly and Pollitt (2010) claimed that district heating shows economic risks in the short to medium term within the current regulatory and economic paradigm. Kelly and Pollitt (2010) pointed out that the UK's district heating schemes' economic viability depends on a set of factors, including upfront infrastructure costs associated with constructions, the volatility of energy and fuel prices, and uncertain energy policies. Moreover, because of higher capital costs and more extended payback periods compared to individual gas boilers, district heating is considered a risky investment in the UK (Hawkey et al., 2013). Nevertheless, the growth of district heating networks has been accelerating over the past few years, with more than 5,500 district heating networks operating in the UK, supplying heat to almost half a million customers in 2018 (ADE, 2018).

2.3.1 The development of district heating technologies

2.3.1.1 The historical development of district heating technologies

Around 1880-1930, the first generation of modern district heating (1GDH) was introduced to supply high temperature heat to a group of local buildings in New York through steam and in situ insulated steel pipes (Lund et al., 2014). One example of the first generation district heating system in the UK is a power station built in 1901 to supply steam to nearby buildings in Bloom Street in Manchester (Woods and Overgaard, 2015). Afterwards, the second generation of district heating (2GDH) emerged in the 1930s, which utilised pressurised hot water with temperatures above 100 °C, with in situ insulated steel pipes. In contrast, the third generation (3GDH) began to utilise renewable energies in the 1970s, supplying hot water that was often below 100 °C through pre-insulated steel pipes (Lund et al., 2014).

3GDH started to utilise alternative resources such as large scale renewables (geothermal, solar, and biomass) and waste energy to deliver heat in high-demand buildings. Soon, district heating was applied to exploit indigenous energy resources to improve energy efficiency and reduce dependency on fossil fuels in countries such as Denmark, Finland, Iceland, and Sweden. In addition, district heating was proven to improve air quality effectively enough to replace coal or oil-fired boilers in cities such as Copenhagen, London, and Stockholm (Bellander et al., 2001; Rezaie and Rosen, 2012; Wiltshire, 2015). Moreover, together with CHP and improved district heating technology, many city-wide networks were established in China, Eastern Europe, the USSR, and South Korea.

District heating technologies have been improving since 3GDH, which mostly utilises fossil fuels to supply heat to high heat demand buildings, and high heat density in cities has been a vital driving factor for the competitiveness of district heating (Lake et al., 2017). In recent years, district heating has been developed as being able to operate with multiple heat sources, to offer higher flexibility and efficiency and reduce carbon emissions, even in areas with low heat densities. The concepts of the fourth generation of district heating (4GDH, Table 2.1) and ‘smart thermal grids’ were defined, featuring intelligent control, incorporation of renewables and waste energy, seasonal thermal storages, low flow and return temperatures, and pre-insulated flexible pipes, to supply district heating and cooling (DHC) in low energy buildings (Lund et al., 2014).

Table 2.1: A summary of key features of four generations of district heating (Lund et al., 2014).

Features	**1GDH**	**2GDH**	**3GDH**	**4GDH**
Time periods	1880–1930	1930–1980	1980–2020	2020–2050
Heat carrier	High temperature steam	Pressurised hot water mostly over 100 °C	Pressurised hot water often below 100 °C	Low temperature water 30–70 °C
Pipes	In situ insulated steel pipes	In situ insulated steel pipes	Pre-insulated steel pipes	Pre-insulated flexible (possible twin) pipes
Buildings and heat densities	Apartment and service sector buildings in the city	Apartment and service sector buildings. 200–300 kWh/m2	Apartment and service sector buildings (and some single-family houses).100–200 kWh/m2	Existing buildings: 50–150 kWh/m2. New buildings: <25 kWh/m2.

Several 4GDH demonstration projects and simulation analyses have proven that low temperature district heating could bring considerable benefits, such as lower exergy and heat loss, reduced maintenance costs, flexible plastic piping, and lower dependency on fossil fuels (Thorsen et al., 2011; Li and Svendsen, 2012; Wiltshire, 2012; Fang et al., 2013). Moreover, low and ultra-low temperatures (with around 25 to 45°C supply temperatures) could maximise the use of low temperature waste heat and increase the efficiency of heat pumps, while meeting users’ comfort and hygiene requirements (Yang et al., 2016). Köfinger et al. (2016) analysed case studies and argue that low temperature district heating can be economically and environmentally advantageous to meet heat demands. It is suggested that based on early 4GDH experiences, there is sufficient technical information to unlock the 4GDH markets worldwide to offer benefits to both the demand and supply sides (IEA, 2017a). Nevertheless, the design strategies are highly dependent on local conditions, such as peak heat demand, availability of heat sources, types of heat pumps, existing networks, business models, and legal conditions, and cannot be implemented in a generalised way.

Furthermore, the fifth generation district energy network (DEN) has been proposed (Figure 2.1) to incorporate both large and small scale renewables and battery storage, while ensuring security and stability of heating, cooling, and electricity services in expandable cities (Rismanchi, 2017). It is believed that the future direction of district energy systems is to become more efficient, with economic and environmental benefits to energy consumers in not only urban but also rural areas (Nijjar et al., 2009). Over time, the role of district heating has become vitally important for cross-sectoral integration to connect low-carbon energy supply and flexible demand controls (Thellufsen and Lund, 2017) to achieve future complex ‘100% renewable smart energy systems’ (Lund et al., 2017).

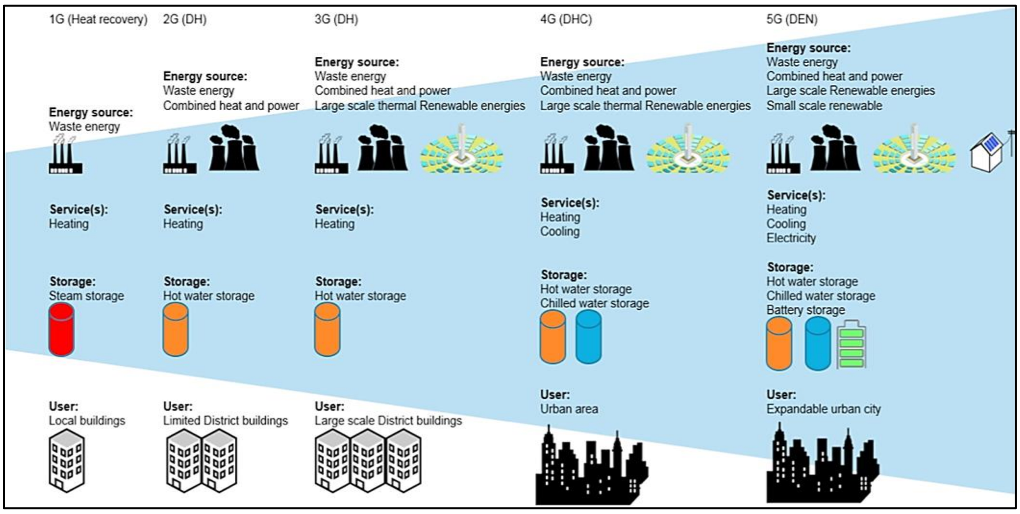

Figure 2.1: The five generations of district energy (Rismanchi, 2017).

2.3.1.2 Future district heating research trends

There are many successful district heating examples around the world that are utilising renewables or recycling wasted heat for heat generation. It has been demonstrated that low temperature district heating networks could bring economic and environmental benefits, and the implementation of 4GDH is anticipated to be carried out soon in countries with well-developed district heating networks (IAE, 2017). In the meantime, in the UK, studies have focused on assessing the feasibility of developing long-term, large-scale district heating schemes, as well as evaluating alternative options. However, many more studies could be done in order to better evaluate the role of district heating networks and heat pumps in the UK's energy system.

The technologies for district heating are continually improving, with expected better performance and lower costs (Sayegh et al., 2017). Traditionally, district heating has a strong dependency on fossil fuels and complex interactions with electricity and gas networks. In recent years, there has been an increasing trend for electricity generation from solar and wind power, and better recycling of waste energy. This promotes the opportunity for the electrification of the heating sector and a shift away from fossil-fuelled heating systems via district heating networks integrated with renewables.

Currently, there are a number of ongoing district heating research projects across many international research institutes or corporate research and development departments (IEA, 2017a; Lund et al., 2018). The potential future research trends can be categorised into five main themes (Magnusson, 2012; Lund et al., 2018; Mazhar et al., 2018; Talebi et al., 2019): first, the future application of district heating in energy systems with flexible electricity and heat demands; second, district heating infrastructure strategic designing, planning, monitoring, and controls; third, implementation of lower temperature levels in district heating networks and low-energy buildings; fourth, optimised district heating system interactions with renewables, waste energy, heat pumps, and storages technologies; and fifth, creation of efficient business models, standards, pricing mechanisms, and policy instruments, and deployment of cost-effective solutions to ensure long-term sustainable heat supply and unlock new district heating markets.

2.3.2 Research on the components of district heating

A modern district heating can be structurally complicated, as it involves different subsystems and can be integrated with other energy networks. This subsection reviews studies on the key elements that a modern district heating system is commonly composed of: heat sources, transmission and distribution, consumption, and thermal storage.

2.3.2.1 Heat sources

Low-cost, reliable, and environmentally sustainable heat sources could determine the technical and long-term financial viability of a district heating scheme. One main merit of district heating systems is that they could offer the flexibility to utilise multiple heat sources, including fossil fuels, renewables, and waste heat. With thermal storage, heat can be generated and stored at lower costs, which makes the timing and operation of heat generation less critical to the smooth functioning of the network. The majority of current operating district heating schemes are supplied through four common sources: direct combustion of fossil fuels; heat from fossil fuel based power stations (CHP) and industries; heat from renewable energy based power stations (biomass CHP and waste incineration plants); and direct use of renewable energy such as biomass, geothermal, solar thermal, wind, and waste heat (Church, 2015; Werner, 2017). Although district heating's fundamental idea is to take advantage of recycled heat or renewables, direct use of fossil fuels at CHP plants or heat-only boilers is still accounting for over one-third of overall current district heating supplies internationally (Werner, 2017).

Intensive research has been carried out to explore alternative sources to be incorporated into district heating schemes in recent years through various methods, including energy system modelling, heat sources and demand mapping, case studies, and feasibility studies. Many studies have demonstrated that geothermal, solar, and biomass can be integrated into existing heating infrastructure to supply heat together with fossil fuels, with reasonable costs (Faninger, 2000; Ozgener et al., 2007; Østergaard and Lund, 2011; Rezaie and Rosen, 2012; Sibbitt et al., 2012; Nielsen and Möller, 2013). Meanwhile, Brand and Svendsen (2013) claimed that in order to achieve the most cost-effective use of renewables and waste heat, the supply temperature of district heating should be as low as possible to integrate low temperature heat sources better and reduce network heat loss.

Heat mapping is a frequently used method in many studies to design heating and cooling strategies. It is also a way to estimate, identify and locate heat demand, renewables, and potential waste heat resources. Heating and cooling demand can be mapped through either a bottom-up approach that gathers individual building characteristics and energy consumption data, or through a top-down approach that applies energy statistics spread over areas via geographic variables. Top-down approaches have been conducted in many studies, together with Geographical Information Systems (GIS) based techniques to investigate heat sources and energy demand based on locations, resource availabilities, and potential technical considerations (Finney et al., 2012; Nielsen and Möller, 2013; Lund and Persson, 2016).

For example, the Pan European Thermal Atlas (PETA) is a top-down interactive tool to assess thermal resources and demand across the 28 EU countries (Stratego, 2017). It models potential waste heat resources and renewables regarding the geometry of local energy demand and prospective district heating and cooling networks. It has been used by the Heat Roadmap Europe project to study future renewable heating and cooling strategies for 14 EU member states (HRE, 2016). Similarly, the top-down National Heat Map (BEIS and CSE, 2017) has mapped the heat densities in England in order to support local planning and implementation of low-carbon heat projects.

However, there are concerns regarding data quality and availability for heat mapping, and most mapping tools are still under development, not ready for the district heating implementation markets. Heat mapping requires high resolutions of geographic details (Nielsen, 2014). Data input is commonly processed from national or European statistics or different projects that were not gathered for heat mapping purposes. Moreover, there is a gap in assessing heat sources and demand between national screening tools and individual project examination tools. There are significant differences in building stocks and occupant behaviours from different regions and countries. There is no standard method to locate and estimate waste heat, and detailed local demand datasets are rarely publicly available due to data ownership issues and privacy concerns. Further, while it is suggested that local authorities tend to use mapping tools for short-term or medium-term planning strategies, there are debates regarding the viability of mapping future heating and cooling demands (Fleiter, 2017).

2.3.2.2 Heat transmission and distribution

The heat carriers in district heating systems have changed from steam and pressurised high temperature water to low temperature water over generations. The majority of district heating pipes are installed underground in soil or bedrock, with occasional examples of overland pipes or pipes in tunnels (Frederiksen and Werner, 2013). The trend has shown the tendency for a reduction in distribution temperatures and thermal losses, pre-fabricated components, improved insulation of smaller pipes, and more flexible materials (Lund et al., 2014). On the other hand, Dalla Rosa et al. (2011) note that lowering the temperature in the networks may increase the pumping energy more than three times. Nevertheless, the total energy for pumping still only accounts for a very small fraction of the overall energy demand, ranging from 0.5% to up to around 2%. Moreover, Tol and Svendsen (2012) claim that appropriate flow rates with optimised pipe layouts and dimensioning could achieve significant savings in heat loss and pumping energy.

From 1GDH to 4GDH, the piping technology and overall performance of heat transmission and distribution systems have been improved incrementally, focusing on maintaining long-term thermal insulation capacity and preventing heat loss. State of the art twin-pipe configurations that are less materially demanding are becoming increasingly popular in modern district heating schemes (Nilsson, 2015). Furthermore, the insulation and casting materials (for example, polyethene and polyurethane) have been improving over time to enhance reliability and durability while reducing investment costs and installation time, and typical pre-insulated bonded pipes are expected to have at least 30 years of service time (Wiltshire, 2015).

Although steam could provide a rapid response to demand and has a high heat content per unit of weight, water has better reliability and higher flexibility and overall efficiency, and often has lower operational and maintenance costs. Most of the 1GDH steam networks have been converted to water district heating or closed, with a few operating schemes in high heat demand density and short pipe areas in New York and Paris (Phetteplace, 2015). Current 2GDH and 3GDH systems around the world are operating at a range of temperature levels, and many studies have indicated the economic benefits of reducing district heating temperature levels (Zinko et al., 2005; Dalla Rosa et al., 2011; Gadd and Werner, 2014).

A ‘smart thermal grid’, which connects low temperature heat sources to low energy buildings, is the key to future district heating systems. The term has been defined as a network of pipes connecting buildings on different scales that can be served from both centralised plants and a number of distributed production units, while better utilising any available sources of heat and focusing on efficient use of future renewable energies (Lund et al., 2014). One of the most critical features of the smart thermal grid is low heat loss, because savings in heat loss from heat transmission and distribution could significantly enhance the competitiveness of district heating. Studies show that the current relative heat loss of DH systems differs from country to country. The typical heat loss from district heating in northern Europe is 8-15%, whereas areas with low heat densities and long distributional distances may have a relative heat loss that reaches over 35% (Frederiksen and Werner, 2013; Danielewicz et al., 2016). Currently, there are limited academic studies focusing on pipe technologies; however, there are many ongoing industrial studies regarding improved pipe thermal insulation, reducing installation environmental impact, and cost-effective leakage detections.

2.3.2.3 Heat consumption in buildings

Commonly, heat is delivered through steam or hot water (sometimes carbon dioxide as an alternative heat carrier) to substations with heat exchangers that transfer heat from district heating networks to buildings. However, compared to the recent fast improvement of other district heating components, there has been little development in substation technologies over the past two decades (Wiltshire, 2012), and researchers have pointed out that there are high proportions of faults in current substations (Gadd and Werner, 2015). There is a lack of academic research in the standardisation of substations with digitalisation and intelligent operational monitoring and control strategies for current district heating substations (Gustafsson et al., 2010).

In residential buildings, heat is mostly consumed to supply space heating and domestic hot water. In some district heating networks, heat from the networks is only used for space heating, and supplementary heating measures are used to produce domestic hot water or boost district heating temperatures (Brand et al., 2010; Zvingilaite et al., 2012). In some cases, district heating schemes may use district heating water directly for domestic hot water, such as some Russian district heating networks (Werner, 2017). It is essential to accurately estimate heat demand and future demand changes in order to design district heating schemes and ensure system performance (Åberg et al., 2012). Under- or over-sizing could lead to lower efficiency, poor controllability, unsatisfied customers, and inaccurate pricing.

Many techniques can be applied to identify and estimate heat demands directly or indirectly, including heat meters, heat mapping, building physics modelling, and analyses of fuel consumption or meteorological data (heat degree days). Swan and Ugursal (2009) reviewed different regional and national residential energy consumption modelling methods. They summarised that residential energy consumption characteristics are complex and interrelated, and each method depends on different amounts and types of data input from which to model energy demand. However, the availability and quality of domestic energy consumption data can vary significantly, which could limit the capability and applicability of the model.

The term 'heat load' is frequently used to describe the amount of heat required to satisfy a consumer's demand over a period of time (Frederiksen and Werner, 2013). Heat load changes over time and differs from consumer to consumer. Daily heat load variations are mainly caused by consumers' social behaviours, while seasonal heat load variations are mostly caused by external temperature changes (Gadd and Werner, 2013). Aggregated heat load must be met by district heating supply (Gadd and Werner, 2013). However, there are limited studies that have examined district heating heat load in buildings on different scales in the UK. A better understanding of heat load patterns could improve the design and control strategies of district heating schemes, enhance the utilisation of storage technologies, and eventually improve the operation of the whole district heating system.

Accurate heat consumption and heat loads are also essential to better design and evaluate district heating tariffs and pricing structures. The ownership and pricing mechanisms are different based on regulated or deregulated markets (Li et al., 2015). District heating networks in Scandinavian countries are mostly invoiced according to heat meters, whereas lump sum tariffs (for example, based on floor areas) are commonly applied in other countries such as Russia and China (Meyer and Kalkum, 2008; Korppoo and Korobova, 2012). The latter pricing method has been criticised for discouraging thermal insulation and energy conservation (Meyer and Kalkum, 2008; Liu et al., 2011). Appropriate metering and pricing methods are necessary for both existing and new district heating schemes, to ensure cost-effective operations, particularly in the UK, where district heating is still considered an expensive and risky investment.

Together with future deployments of district heating, it is suggested that energy savings through building renovations are crucial to achieve better system performance and reduce whole system costs (Åberg and Henning, 2011; Sayegh et al., 2017). Energy efficiency measures and high-efficiency building materials are undoubtedly the best approaches to reduce heat demand and emissions in new buildings (ERP, 2017). Dalla Rosa and Christensen (2011) confirmed that low temperature district heating with energy-efficient buildings could reduce primary energy consumption by around 14% and halve distribution heat loss compared to conventional high temperature networks, through simulating steady-state heat loss in buried pipes.

However, there are considerable technical, financial, and social barriers to improving the thermal insulation of existing buildings and encouraging current gas-heated houses to switch to district heating (IEA, 2017b). Connolly et al. (2014) argued that deploying energy efficiency measures could provide crucial heat demand reduction, but until this reaches a certain point when further improving energy efficiency measures become costly and there are fewer opportunities, it could become complicated and expensive to implement. The synergistic balance between heat savings and the heat supply through district heating is a great challenge for district heating strategic planning. Some research suggests that heat saving measures should be implemented until the cost of a sustainable price is less than the marginal cost of additional heat savings (Andrews et al., 2012; HRE, 2016).

2.3.2.4 Thermal energy storage

Heat demand varies over seasons and times of day in many countries, with heat demand much higher in the winter and daytime. Thermal storage has been used to counteract the fluctuations of daily heat loads and heat supplies in district heating schemes. Recently, large-scale inter-seasonal storage has been integrated with solar district heating in some European countries

(Winterscheid et al., 2017). There are three main types of thermal storage based on the physical and chemical properties of the storage materials: sensible heat, phase-change, and thermochemical reactions (Faninger, 2004). Bauer et al. (2010) examined different seasonal thermal storage pilot examples and suggested that the capital costs and thermal loss are too high for tank and pit storage in Germany, and the type of storage must be cautiously selected based on individual district heating conditions and storage operational characteristics.

The utilisation of thermal storage in district heating systems could decouple heat consumption and generation, and offer profits and flexibility amid fluctuating heat demand and renewable supply, in addition to better utilisation of low temperature renewable heat and higher efficiency of heat pumps (Lindenberger et al., 2000; Marx et al., 2014). Case studies have demonstrated the implementation of thermal storage in Danish district heating schemes, where the surplus electricity is used to generate heat by electric boilers or heat pumps when the electricity price is low (State of Green, 2016).

As a mature and reliable technology, hot water tanks are the most common commercially available domestic thermal storage systems (LCICG, 2012). At the district level, above-ground tanks are commonly used as short-term storage for district heating, and Thomsen and Overbye (2015) demonstrated that the tanks could be either centralised (co-located with heat generation such as CHP plants) or decentralised in the networks according to the system design. On the other hand, many studies have examined large-scale long-term storage technologies, particularly in solar district heating systems, such as pit storage (or buried water tank storage) and aquifer and borehole thermal storage (Pauschinger, 2011; Pinel et al., 2011; Xu et al., 2014).

Several demonstration projects have shown successful thermal storage systems to store heat over weeks or months without excessive losses (SDH, 2017). The most extensive seasonal pit heat storage in Vojens, Denmark, has a 70,000 m^2 solar heating plant and can store 205,000 m^3 of hot water with only about 8% heat loss a year (Ulbjerg, 2016). Moreover, Verda and

Colella (2011) used a multi-scale model to assess the impact of thermal storage on CHP district heating schemes, and results have shown that thermal storage could help to decrease up to 12% of primary energy consumption and 5% of total costs.

Furthermore, thermal storage is substantially cheaper than electricity storage (Lund et al., 2016), and it could offer additional benefits for power plants (González-Portillo et al., 2017). It decouples the electricity generation from heat load for CHP plants as electricity could be generated when the price is high, and heat could be stored and used when heat demand is high (Paiho and Reda, 2016). Fragaki et al. (2008) proved that because the UK's electricity tariffs vary between day and night, thermal storage could increase the economic return of a CHP by up to 15% annually on average.

However, the type and size of thermal storage systems must be carefully selected and designed according to specific district heating schemes. Nuytten et al. (2013) used a generic model to assess the flexibility of thermal storage and argued that centralised storage with CHP provides more flexibility than individual units. Martínez-Lera et al. (2013) analysed the optimal sizing of thermal storage units for CHP plants. Through thermodynamic and economic performance evaluations, they confirmed that adequate thermal storage sizing and operation period could bring not only energy savings, improving thermal efficiency, but also economic profits for power plants.

2.4 Heat pumps in district heating

Heat pumps are able to not only replace gas boilers in individual households but can also be integrated into district heating networks. Heat pumps are commonly utilised in district heating schemes in three main ways. First, heat pumps are integrated into existing networks (commonly with a flow temperature above 70°C) as additional heat generators, or together with combined heat and power (CHP) plants for heat recovery. Second, new district heating systems are developed with large heat pumps with low flow temperatures. Third, decentralised heat pumps are used in very low temperature networks to act as temperature boosters. Frederiksen and Werner (2013) state that decentralised heat pumps and centralised heat recycling systems are anticipated to become an economically viable and robust approach to meeting both heating and cooling demands in buildings in the future.

Many previous studies on heat pumps in district heating can be categorised into five main perspectives. The first perspective includes technical, design, operational, and performance assessments of heat pumps in district heating networks, assessing how they perform inside and outside of buildings. The second perspective focuses on potential heat sources and applications of thermal storage for heat pumps in district heating. The third perspective involves integrating heat pumps and district heating with current heating options or replacing them and evaluating their impact on the energy system. The fourth perspective includes heat pumps and district heating business models and competitiveness and consumer acceptance studies, including financial analyses and cost reduction projections. The final perspective includes heat pumps and district heating demonstration projects, and implementation strategies that illustrate the benefits and drawbacks of deploying heat pumps in district heating.

Heat pumps with a capacity of over 100 kW are considered as large, and can reach several megawatts easily, with the current single largest European heat pump unit reaching 35 MW (EHPA, 2018a). Industrial-sized heat pumps could provide heat for over 20 years and can be integrated into a broader energy system (Star Renewable Energy, 2017). Integrating large heat pumps into district heating networks has been considered as an important step in transitioning to a 100% renewable energy system cost-effectively (Connolly and Mathiesen, 2014). Studies have proved that large scale heat pumps could effectively make use of the production of excess electricity in Denmark, which has high levels of renewable electricity generation (Mathiesen and Lund, 2009), and this could potentially eliminate fossil fuel consumption with similar or lower current heat costs (Pensini et al., 2014). Meanwhile, many current district heating schemes extract heat from sewage water, ambient water, industrial waste heat, geothermal heat, and flue gas via large scale heat pumps (Nowak, 2017).

Bach et al. (2016) used the Balmorel energy model to evaluate seasonal performance variations and the optimum dispatch of heat pumps in district heating systems. They suggested that heat pumps integrated into a distributional network (downstream) perform better than those integrated into transmission networks (upstream). Østergaard and Andersen (2016) estimated that district heating with heat pumps could reduce up to 40% of operational costs compared to district heating without heat pumps due to high efficiency and low heat loss. Similarly, Ommen et al. (2014) suggested that with heat pumps at CHP plants to increase the return temperatures, the operational cost of 90/40°C district heating networks could reach as little as 12€/MWh. Likewise, Lund et al. (2016) explored the feasibility and socio-economic potential of utilising large heat pumps in Danish district heating schemes. They proposed that this could reduce the total system energy cost by 100 M€/year by 2025.

There are many large scale heat pumps (over 10 MW per plant) operating in some European countries as power-to-heat solutions in district heating schemes (Lund, 2015; Lund et al., 2016; Nowak, 2017). Averfalk et al. (2017) reviewed large scale heat pumps in Sweden installed in the 1980s, regarding their installed capacities, utilised capacities, heat sources, competitiveness, and operating experiences. The study revealed that over

1500MW of heat capacity was installed, and 80% of this capacity is still in use, and those heat pumps have been operating continuously over the last three decades. However, Lygnerud and Werner (2017) suggested that many large heat pumps in Sweden are outdated, and it is uncertain how long these heat pumps will continue to function in the future. The surplus heat from nuclear plants prominently stimulated the deployment of heat pumps in Sweden three decades ago. It is possible that this could happen again in Sweden and many other countries with the increasing electricity generation from renewables.

Similarly, David et al. (2017) examined the evidence from 149 units of large scale electric heat pumps (with a thermal capacity larger than 1 MW) in district heating schemes across 11 European countries. They concluded that large scale heat pump technologies are mature enough to implement in other locations in Europe. It is suggested that the aggregated large scale heat pump capacity in Europe could reach 40GW and constitute up to 30% (producing 520 TWh/year of heat) of total district heating in 2050 (Connolly et al., 2012; Connolly et al., 2013). Although there are concerns relating to the operation and maintenance of large heat pumps (Averfalk et al., 2017), policy and socio-economic limitations have become more important barriers than technical constraints in limiting the expansion of large scale heat pumps (David et al., 2017).

There has been a rapid expansion of district heating networks in the UK in recent years (ADE, 2017), of which many of the networks involve district heating connected to CHP plants (CIBSE, 2017). However, the number of applications of heat pumps in district heating schemes is very small. At this moment, none of the operating heat pumps in existing district heating networks has a capacity larger than 10MW (DECC, 2016b; Star Renewable Energy, 2017). Further, although heat pumps working as boosters enable the network to operate at lower temperature levels with lower thermal losses and costs, there is a lack of examples of commercially deployed district heating networks in the UK that integrated with small scale individual heat pumps for residential heating.

2.5 District heating modelling studies on different scales

A significant number of modelling tools have been developed to explore district energy systems, together with better utilisation of renewables, storage, and heat pumps (Allegrini et al., 2015). With different temporal and spatial resolutions, some focus on the micro scale to simulate the components of district heating systems or individual building characteristics, while others investigate on the macro scale to examine district heating at the national or multi-national level. However, very few can address every building of an area in addition to hourly or sub-hourly energy demand (Frayssinet et al., 2017). Further, it is a common approach for modelling studies to apply simplified universal assumptions, such as using fixed scales of heat pumps, district heating networks, and buildings; therefore, there is a lack of academic research investigating district heating and heat pumps across different scales.

Modelling tools have been developed either for the understanding of district heating systems or for planning and optimisation of district heating networks. It is suggested that large network simulation can be computationally intensive (Larsen et al., 2002), and some studies have been carried out to simplify physical and mathematical models to represent the dynamic characteristics of district heating networks (Larsen et al., 2004; Jie et al., 2012). Many detailed models have been developed to study some key parameters in district heating systems in detail, such as mass flow rates, temperature levels, thermal behaviours of pipes, and thermal storage. Three in-depth district heating simulation tools, Modelica-Dymola, Apros, and IDA-ICE, were commonly used for evaluating the performance of components of a district heating network (del Hoyo Arce et al., 2017). Allegrini et al. (2015) reviewed 20 cross-disciplinary software tools that can simulate urban district energy systems, and they suggested that district energy networks are key enabling technologies in achieving high levels of renewable energy generation and utilisation. Evins (2013) suggested a growing interest in parametric modelling for multi-objective optimisation analyses in buildings. However, many of these studies highlighted that data availability has long been a major concern in district energy modelling.

Previous studies that assessed heating measures at the individual building or local level are often case studies from different perspectives. Many early studies argued that district heating might not be an economically suitable heating alternative for houses with low demand (Gustavsson and Karlsson, 2002) because of its high capital costs. However, many studies have presented different views. Joelsson and Gustavsson (2009) studied the economic and environmental impact of switching heating measures among district heating, heat pumps, and biomass on primary energy use and costs based on two detached houses in Sweden. Results revealed that improved building materials and district heating based on biomass might reduce up to 88% of primary energy demand and 96% of carbon emissions compared to the fossil fuel-based heating systems. However, this study also admitted that district heating and pellet boilers were less economically competitive than individual heat pumps in smaller houses. Additionally, the short-term and long-term importance of implementation of heat saving measures together with district heating in relation to overall fuel efficiencies has also been emphasised by studies in Denmark and Norway (Thyholt and Hestnes, 2008; Sperling and Möller, 2012).

Techno-economic analyses suggest that district heating is associated with high costs, mainly due to capital costs and pipe network costs (Davies and Woods, 2009). Pirouti et al. (2013) investigated cases of designing networks that connect a group of buildings to minimise energy consumption and capital costs, finding that smaller pipes are more economical, and that space heating demand and heat loss could be reduced when the system flow rate is reduced.

However, it is essential to design district heating networks according to both space heating and domestic hot water demand in buildings. Chmielewska et al. (2017) reviewed different models and tried to estimate domestic hot water consumption in a group of flats based on the number of rooms and floor areas. Although many models assume a linear relationship between domestic hot water consumption and floor areas, the study highlighted that it is difficult to estimate the number of occupants, which could influence the results.

The heat demand in future buildings is projected to decrease incrementally due to better insulation and performance, with an expected reduction in district heating capital costs due to technology innovations (Persson and Werner, 2011; Li et al., 2013). Moreover, there are a number of energy models that simulate electricity and heat demand in buildings on a city scale (Allegrini et al., 2015; Frayssinet et al., 2017), and many of them can be used to explore district heating in the UK. Some argued that city-level energy consumption could be simulated based on dwelling types (Shimoda et al., 2004), and that district level energy demand forecasting can be done through 3D models to estimate energy demand from a group of buildings (Strzalka et al., 2011). However, explicitly modelling each building in great detail is required in order to accurately simulate and forecast the heat demand of an area or a city, and data availability and quality have been the most challenging issues.

Many energy system studies claimed that the best technical solution to meet future heat demand was a gradual expansion of district heating on the national and the EU level, starting with high energy density areas, with individual heat pumps in remaining areas (Lund et al., 2010; Mathiesen et al., 2011). Furthermore, Möller and Lund (2010) used a GIS-based spatially explicit economic model together with energy system models to study the costs of replacing individual gas boilers with district heating in Denmark. Individual heat pumps were found to be the best socio-economically reasonable alternative to district heating, while hydrogen fuel cell micro-CHP does not decrease fuel demand, carbon emissions, or costs due to its high cost and low efficiency. However, whether the results from European countries could be extrapolated to the UK needs further studies, due to the differences in geography conditions, the structures of their energy systems, and technology implementation costs.

2.6 Research gaps and opportunities

It is possible to achieve deep cuts in carbon emissions from British dwellings through improvements in building performance, decarbonising electricity, and re-engineering the heat supply (Lowe, 2007). However, the future of residential heat demand and supply are very uncertain (Eyre and Baruah, 2015). The mass electrification of the heating sector and the deployment of heat networks on large scales will require intensive investment, alterations in supply chain practices, and public acceptance. There is no general agreement regarding the best way of supplying heat sustainably in the UK.

As highlighted by the CCC (2019), the current set of policies is not effective in decarbonising the heating sector, and the number of heat pumps deployed remains very low. Strong government leadership, with a stable comprehensive policy framework and clear strategic decision-making, is required to ensure progress in decarbonisation and the transformation of the heating system. Furthermore, there are a great number of challenges in relation to the decarbonisation of the electricity grid, and uncertainties in future carbon prices, peak demand variations, and market development of heat pumps and heating networks (Chaudry et al., 2015). With continual improvements in heating technologies (Sayegh et al., 2017), evaluating their advantages and performance is essential to determine the direction of long-term heat decarbonisation and develop a low-carbon heat infrastructure.

Previous heating technology studies have frequently highlighted the importance of high quality heat demand data. Quantifications of heat consumption and peak demand from different types of domestic buildings are essential to examine alternative low-carbon residential heating technologies. Although many studies have examined electricity load profiles for British residential buildings using empirical data (Bagge and Johansson, 2011; Christoph et al., 2012; Luo et al., 2017), very few studies have analysed heat load profiles using actual energy consumption data. Heat demand profiles are difficult to model accurately due to complex interactions between weather conditions, fuel consumption, the thermal properties of buildings, and occupants' behaviours. There is a very low uptake of heat meters in the domestic buildings (DECC, 2014b), and measured energy demand data are often kept confidential for commercial and privacy reasons. Furthermore, most accessible empirical heat demand data are highly aggregated and recorded at the national and regional levels.

Understanding heat load profiles from British dwellings and their aggregations is imperative to appropriately design, size, and construct district heating systems economically. They are particularly crucial for planning short-term generation, designing energy distribution networks, and deploying marketing initiatives, such as proposing peak and off-peak tariffs. They are also critical inputs to longer term decision making, infrastructure planning, and developing energy models that can be used by utilities, researchers, policymakers, and others.

Some studies have been carried out to investigate residential heat load profiles in selected European countries (Yao and Steemers, 2005; Carmo and Christensen, 2016). Nevertheless, the generalisability of European studies to the UK context is rather controversial, and heat demand is likely to change based on different heat supplying technologies. The UK has less-developed heat networks than gas networks, low heat pump deployment, and few studies examining the potential of electrification of the heating network. The UK also has different building characteristics and heating behaviours from European countries. The results from studies focusing on different European countries may also vary due to different building characteristics and heating behaviours.

Most previous literature on heat pump and district heating studies does not differentiate between energy demand from different dwelling types based on empirical data. There is a diverse range of types of residential buildings in the UK. The overall heat demand and demand patterns are likely to vary based on the types and ages of the dwelling and occupancies. Further, the variations in heat demand patterns from individual dwellings will determine the aggregated heat demand profiles according to different seasons and times of the day. Very few studies explore the energy demand diversity empirically at intermediate scales, such as at the neighbourhood and community levels.

Many previous heat pumps and district heating studies are limited to either focusing on individual projects or examining the whole energy system at a national or multi-national level, without specifying how heat pumps, buildings, and district heating networks are or might be interconnected. Heat pumps may work differently based on where and how they are installed and operated in the district heating system. Their costs and performance could be significantly affected by these factors. There has not been a study in the UK that has systematically explored the comparative advantages of integrating electric heat pumps into district heating through different topological configurations. A comprehensive study could distinguish the economic and environmental trade-offs of deploying heat pumps with district heating for different dwellings at different scales.

With an interest in investigating the balance between heat demand, diversity, heat generation, costs, and carbon emissions according to the UK's building characteristics, this study aims to quantify the technical, economic, and environmental features of different configurations of heat pump deployment, from individual buildings to district heating networks. This study can offer a better empirical understanding of heat demand heterogeneity in buildings at different scales; assess heat pump and district heating costs in the UK and thereby contribute to energy demand research in the built environment; and support the planning and implementation of heat pumps and district heating systems.

2.6.1 Research methodology for this study

Different research methods and types of data are applied in this study to address the two subsidiary research questions. To answer the first subsidiary research question, an empirical quantitative analysis of energy consumption data is conducted to investigate energy demand and load profiles in the five main types of British dwellings. As for the second subsidiary research question, a techno-economic assessment model is built to explore topological configurations that integrate dwellings, heat pumps and district heating networks from the individual dwellings to different scales of district heating networks that connect different dwellings and occupant diversities.

A brief summary of approaches to the study of each subsidiary research question is illustrated below. Detailed research methods and data are further justified and discussed in the methodology sections in Chapter 3.3 (page 85) and Chapter 4.3 (page 155), respectively.

2.6.1.1 Empirical energy demand data analysis

Subsidiary research question 1:

How much heat demand is required for different types of domestic buildings, and how does the peak of the aggregated heat loads change due to diversity and scaling effects at district levels?

Approaches:

- To gather historical smart meter and weather data and estimate annual heat demand and winter peak hourly loads in the five main types of dwelling in the UK: detached houses, semi-detached houses, terraced houses, bungalows, and flats.
- To analyse aggregated energy load profiles from dwellings at different scales due to diversity across a range of scales from a small group of dwellings as few as ten dwellings, to large scale systems

with thousands of dwellings in one network.

- To compare energy load profiles from smart meter field trials with those from domestic electric heat pump field trials.

Heat demand is quantified for the five main types of dwellings through gathering empirical energy consumption data and the metadata from the largest smart meter field trial in the UK, using gas consumption as a proxy. Hourly load profiles are investigated for each type of dwelling over a day and a year respectively to analyse variations in daily and annual energy consumption as well as winter peak demand. Different levels of temporal aggregations are applied to explore the aggregated load profiles, and the demand diversity effect is explored from individual dwellings to larger scales that could be supplied through heat pumps and district heating networks.

Domestic energy consumption data from the Energy Demand Research Project (EDRP) and its subsets from EDF Energy are used for this study. The EDRP was a trial implemented by four major energy suppliers to investigate smart meters, customer responses, and individual domestic energy consumption in over 60,000 households, including approximately 18,000 with smart meters, across Britain from 2007 to 2010 (AECOM, 2011). A large number of participating households made this dataset beneficial for this research question as the EDRP collected half-hourly electricity and gas consumption data in different types of residential buildings. However, the publicly released EDRP dataset has limited metadata following a set of anonymisation processes. Consequently, dwellings' locations, ages and types were only available at an aggregate level (AECOM, 2018). Therefore, this study also utilises a subset of the EDRP dataset from EDF Energy, which contains monitored half-hourly energy consumption data from 1,862 households and dwelling metadata regarding their ages and types.

Moreover, datasets from the Renewable Heat Premium Payment (RHPP) scheme are obtained to analyse heat load profiles in dwellings with individual heat pumps installed. The RHPP dataset contains electric heat pump data collected from a detailed monitoring campaign, which included 700 individual domestic heat pumps monitored between October 2013 and March 2015 (Lowe et al., 2017). A publicly available, cleaned dataset covering more than 400 households was used for this study (UK Data Service, 2019).

2.6.1.2 Heat pumps and district heating techno-economic modelling

Subsidiary research question 2:

What topological configurations of heat pumps and district heating could be implemented for the UK's dwellings, and what are the economic and environmental advantages or disadvantages of deploying heat pumps in different topological configurations?

Based on the results of empirical heat demand analyses from the first subsidiary research question, a technological, economic, and environmental assessment model is built to assess heat pumps in different dwellings and evaluate the environmental and economic trade-offs between four topological configurations where heat pumps are installed at individual dwellings or integrated into district heating networks. Five scales of district heating networks are defined based on the government and municipal standards according to the number of dwellings in one connected network.

Approaches:

- To compare heat demand and fuel consumption for five types of individual dwellings and different district heating networks at five different scales.
- To model heat delivered to buildings and heat loss through transmission and distribution networks according to different district heating technical parameters operating conditions including pipe

sizes and lengths, flow and return temperature levels and network scales.

- To evaluate different cost components, levelised cost of heat and carbon emissions to meet heat demand in different dwellings and topological configurations that integrate heat pumps into district heating networks.
- To investigate the implication of economies of scale in heat pumps and district heating networks when the sizes of heat pumps and heat networks increase, in terms of distribution and transmission losses, levelised cost of heat, initial construction costs, and carbon emissions.

A techno-economic assessment model is built to investigate discounted cash flow over the lifetimes of different heat pumps and district heating topological configurations. The model compares the economic quality and comparative environmental advantages of different options to meet heat demand by utilising heat pumps in different ways. Levelised costs of heat, initial capital costs, and carbon emissions from different configurations are compared to a reference case where heat is supplied only by individual gas boilers. Moreover, different types of fuel pricing mechanisms, annual fixed prices versus time-of-use tariffs and retail versus wholesale prices, and their potential applications for heat pumps and district heating networks are investigated.

There are three main categories of data inputs and assumptions that are used to construct the model:

1. Heat demand from dwellings.

2. Heating technology parameters and performance.

3. Costs. There are a number of cost factors in the model: capital costs of installing heat pumps or constructing the district heating networks; heat pumps and district heating operational maintenance costs; gas and electricity costs; and carbon costs.

Data sources and critical assumptions for these three categories are summarised and further discussed in Chapter 4.3.4. The results from load profiles and demand diversity in Chapter 3.4 are used as model inputs to quantify heat demand in different dwellings and district heating networks. Heat pump and district heating technical features and cost data are gathered from a range of sources, including academic literature, government commissioned datasets and reports, industrial marketing materials, technical catalogues from heat pump and district heating manufacturers and practitioners, and data released by energy service consultancies and utility companies.

Chapter 3: Analysis of empirical heat demand in British dwellings

This chapter addresses the first subsidiary research question of this thesis:

How much heat demand is required for different types of domestic buildings, and how does the peak of the aggregated heat loads change due to diversity and scaling effects at district levels?

Some figures and discussions in this chapter have appeared previously in the following conference/publication:

Wang, Z. 2019. Understanding aggregated domestic energy demand and demand diversity in Great Britain. *The 5th International Conference on Smart Energy Systems*. Copenhagen, Denmark.

Wang, Z., Crawley, J., Li, F. G. & Lowe, R. 2020. Sizing of district heating systems based on smart meter data: Quantifying the aggregated domestic energy demand and demand diversity in the UK. *Energy,* 193**,** 116780.

Summary of Chapter 3

Quantifications of energy consumption and peak heat demand are the fundamental factors relating to the size and costs of installed capacities of heat generation, transmission pipes, and substations of district heating networks. The sizing of energy conversion and distribution systems involves a trade-off between reliability and continuity of service, and avoidance of capital and running costs associated with oversizing. Finding the most appropriate sizing requires a thorough understanding of energy load profiles. However, empirical data necessary to support such an understanding is not always available; therefore, engineering design tends to become defensive and domestic energy systems are typically oversized.

Energy demand diversity reduces peak loads at an aggregated level and is a crucial factor contributing to economies of scale in the energy industry. There is limited empirical research to explore, quantify and discuss this phenomenon through actual residential heat consumption data on a large scale. This chapter offers quantifications of annual heat demand and peak hourly demand, as well as a better understanding of residential heat demand heterogeneity in British dwellings, by analysing empirical gas consumption as a proxy for heat demand from the most extensive public smart meter field trial conducted in the UK, together with monitored data from domestic heat pump field trials. Meanwhile, domestic electricity load profiles and peak demand are investigated to be compared with gas consumption.

This chapter quantifies and compares seasonal and daily variances in residential gas and electricity consumption patterns throughout a consecutive year, appraises the weather dependence of electricity and gas loads, and highlights peak hourly energy consumption on the coldest weekday and weekend in winter 2009/2010, which was one of the coldest winters in Britain over the last three decades. It also explores the diversity effect in residential energy consumption and computes the after diversity maximum demand (ADMD) as a function of the number of dwellings connected in one system.

This empirical quantitative analysis of diversity can support the improved design of district heating networks, and, in particular, enable reduced capital and running costs by appropriately sizing heat pumps and district heating subsystems, contributing to an improved understanding of economies of scale for heat networks. Furthermore, results from this chapter can be applied to plan and manage district heating generation, transmission, and distribution systems, particularly in forecasting heat demand, designing control mechanisms and regulating economic grid operations, to ensure district heating infrastructure reliability while reducing capital costs and the risks of over- or under-sizing and interruptions to services.

3.1 Introduction

With the projected future growth in the microgeneration of renewable energy and the deployment of electric vehicles, heat pumps and district heating networks, residential demands for electricity and heat may change significantly. Empirically-based energy load profiles have become vitally important for evaluating strategic options to design, plan, and implement demand-side management and future energy supply technologies (Strbac, 2008). They can be used to ensure that installed technologies' capacities are able to meet the maximum energy demand, as well as any unpredictable demand increases, alongside improved utilisation. Due to the growing installation of smart meters during recent years led by energy suppliers in the UK, high time-domain resolution studies of energy demand profiles have been made possible, offering detailed empirical knowledge related to the characteristics of domestic energy demand patterns.

Energy load profiles can illustrate how energy is consumed over time, and can be aggregated according to different spatial and temporal scales as the results of interactions between various subsystems. Individual households can, for a number of reasons, have very different energy demand patterns, and not all customers will likely demand their peak energy use at precisely the same time. Consequently, when individual households are combined into a group at an aggregated level, the maximum demand arising from a group of households is less than the sum of the individual maximum demands due to diversity, the reason being that individual demand peaks are unlikely to occur simultaneously. Hence, the maximum demand per household declines when more households are added to a given system. The term 'demand diversity' is used to describe this phenomenon, which is a key determinant of capital costs and economies of scale for energy generating and transmission technologies, and of distribution losses in heat networks. Nevertheless, there is a lack of empirical investigations regarding the diversity effect of energy consumption at an aggregated level, and very few studies have investigated domestic heat load profiles or their aggregation.

The diverse variations in energy consumption behaviours between individual residents will determine the aggregated energy demand characteristics, according to different seasons and times of the day. Studies have demonstrated that aggregated electricity load profiles can provide seasonal and intra-daily characteristics of consumption patterns in different types of households (Chang and Lu, 2003; McLoughlin et al., 2015), and can be applied to load management based on different levels of temporal aggregation (Sajjad et al., 2014). Load predictions have been recognised as crucial input parameters for planning mixed energy distribution systems (Pedersen et al., 2008).

Furthermore, energy load profiles can be applied to evaluate investments, design contracts and tariffs, regulate energy generation and purchasing, and develop and validate energy models. Nevertheless, perhaps reflecting the historical dominance of gas and electric heating, there is little detailed published information on monitored hourly heat load profiles for the UK's individual dwellings. Such load profile studies that have been published have relied on theoretical modelling or small samples, which do not support a thorough understanding of the stochastic nature of demand and its aggregation on a large scale.

Individuals' peak demands and how they are aggregated are crucial factors for determining the size of energy generation, transmission, and distribution systems. Studying end-use energy load profiles and diversity at high temporal resolutions is advantageous when designing load control mechanisms and economic grid operations, as energy supply and distribution systems can benefit from economies of scale, which can reduce capital investment. For example, results from peak heat demand and diversity studies allow heat supplying utilities to prepare for peak loads and purchase equipment that has a rated generation capacity that is less than the sum of all the individual peak demands from all the individual consumers.

Peak energy load profile studies can be analysed by modelling or monitoring energy data. The Danish Standard DS439 (Dansk Standard, 2009) is the most commonly used standard in the district heating sector to design the maximum capacities of the heating systems, and this standard has been adopted by the heat network Code for Practice for the UK (CIBSE and ADE, 2015) as the standard diversity curve to size heat generations. However, the Code for Practice (CIBSE and ADE, 2015) specified that the best practice for managing peak demand should be determined by monitoring the heat currently supplied to the building or its fuel use, using meters and recording data at hourly or half-hourly intervals. They also emphasised that a full year's data would be very valuable and needs to include monitoring of external air temperatures. However, Spoladore et al. (2016) pointed out that the monitored hourly profile of single users' heat demand is commonly unknown. The empirical literature on detailed peak hourly heat load profiles in different types of buildings across a large sample size in the UK is currently limited.

Multiple studies of energy supply security find substantial increases in energy use and peak demand during certain parts of the year, associated with seasonal weather conditions in different countries (Ziser, 2005; Wan et al., 2012; Hong et al., 2013). Psiloglou et al. (2009) compared time series electricity load profiles and potential factors affecting peak electricity demand for Athens and London between 1997 and 2001. This study claimed that air temperature played the most crucial role in affecting the electricity loads in both cities, and that electricity demand levels increased substantially when the air temperature dropped below 16 ℃ in both cities, but only increased slightly when the air temperature went above 16 ℃ in London.

After a cold weather event (the Beast from the East and Storm Emma) in late February and early March 2018, Wilson et al. (2018) studied Britain's aggregated hourly gas demand and electricity supply. During this cold wave with widespread snow and negative air temperatures across Britain (The Guardian, 2018). It was indicated that the peak hourly gas demand in Britain increased dramatically, by 116 GW (from 89 GW to 205 GW) on 28th February from 5:00 to 8:00 (Wilson et al., 2018). Furthermore, Wilson et al. (2018) also highlighted that meeting the peak energy demand might be critical to the management of the whole energy system during extreme weather events.

In heat supply industries, the ‘rule of thumb’ approach is commonly used to assess heat loads and demand diversity, and often according to the number of customers, floor areas, or set temperatures. Installers who are trained to design gas boiler-based systems often deliberately oversize heating systems and use this as an insurance against inadvertent under-sizing (Cosic, 2017). A comprehensive knowledge of actual energy load profiles and diversity is essential for efficient and reliable heating system designs, particularly for the future deployment of district heating networks. This chapter gathers and analyses empirical data from a large group of households to compare historical gas and electricity consumption versus external temperatures, and thereby offer a better understanding of domestic energy demand and energy diversity in British dwellings.

3.2 Literature review

3.2.1 Energy load profile studies

Energy load profiles are crucial to both electricity and heat industries, as long-term and short-term load profiles have many applications. High-resolution energy consumption data monitored from individual dwellings can offer benefits for analysing load profiles and evaluating domestic energy demand. Annual load duration curves, and daily or hourly peak and off-peak load profiles are required for modern district energy transmission and distribution systems, particularly in load forecasting, to ensure reliability while reducing the risks of over- or under-sizing, and interruptions to services (Willis, 2002).

There is ample literature on residential electricity load profile modelling in the UK on different scales (Richardson et al., 2010; Good et al., 2015). For example, Grandjean et al. (2012) reviewed 12 domestic electricity load curve modelling studies that applied top-down or bottom-up approaches across different countries. They argued that many models only considered diversity directly from the input assumptions without clarifying it, or generated diversity based on random processes such as probability distribution functions and Monte Carlo approaches. Torriti (2014) examined electricity demand models and their input data from a group of European studies, including the UK. The results highlighted the limitations of model assumptions and the significance of future monitoring studies based on actual end users' smart metering data.

Furthermore, Jones et al. (2016) reviewed factors that affect domestic electricity demand, including socioeconomics, types of appliances, and types of dwellings, in the UK. Then, they analysed the factors that could lead to high electricity demand in households, namely socioeconomic and dwelling factors, through analysing the data of a city-wide survey (Jones and Lomas, 2015; 2016). Similarly, McKenna et al. (2016) modelled the socioeconomic diversity and the effect of aggregation on the domestic electricity load profiles at the neighbourhood level, using differentiated dwelling archetypes for English and Welsh dwellings. They found that temporal variations in electricity loads were considerably affected by household socioeconomic characteristics.

Although much research has studied electricity load profiles for British residential buildings using empirical data (Bagge and Johansson, 2011; Christoph et al., 2012; Luo et al., 2017; Ramírez-Mendiola et al., 2017), there have been few studies of heat load profiles using actual energy consumption data from large samples. Previously, many studies have investigated the impact of building characteristics and occupants' behaviours on heat demand (Hens et al., 2010; Guerra Santin, 2011; Ren et al., 2015). For instance, Kelly et al. (2012) applied panel methods to explore internal temperature demand across the English dwellings over time by analysing monitored temperature data and incorporating building typologies, energy efficiency measures, and occupants' sociodemographic and behavioural features. Moreover, Kane et al. (2015) found that heat demand and heating patterns differed significantly in those households according to occupants' ages and employment statuses through examining indoor temperature measurements and sociotechnical surveys. However, although these studies utilised empirical temperature data to study heat demand, they did not measure heat demand (in terms of kWh) directly.

Moreover, through different research methods, a wide range of studies have demonstrated that building characteristics and empirical energy consumption data are crucial for accurately modelling heat demand, quantifying domestic heat demand changes over time, and assessing buildings' energy performance. Yao and Steemers (2005) developed a simple approach to formulating the daily heat load profiles in different types of domestic buildings in the UK based on a thermal dynamic method and measured physical characteristics of buildings. Alternatively, Shipworth et al. (2010) studied central heating durations and thermostat settings from a national survey of energy use, while Summerfield et al. (2010) monitored temperatures and changes in energy consumption in a group of dwellings in England over 15-17 years. Additionally, Summerfield et al. (2015) analysed energy consumption data from smart meters and explored 24-hour delivered power profiles to categorise dwelling energy performance and quantify energy savings from retrofitting.

Heat demand is rarely measured directly. It is challenging to predict instantaneous residential heat demand, as it emerges from complex interactions between building envelopes, heating systems, weather conditions, and occupants' behaviour. Fundamentally, the phenomenon is a sociotechnical one (Chiu et al., 2014; Lowe et al., 2018). Where it is available, gas consumption data can be used, with caveats, as a proxy for heat demand. It is not possible to cleanly separate out cooking loads from space and water heating. The technical characteristics of gas boilers, and the fact that occupants adapt their behaviours to the specific technical characteristics of heating systems and to energy tariffs, mean that patterns of heat demand for gas-heated homes, inferred from metered gas data, may differ from patterns of heat demand for homes connected to heat networks, measured with heat meters. However, high-quality metered heat demand data from real district heating networks are very scarce, due to the limited development of district heating networks in the UK.

Furthermore, most monitored residential energy data are kept confidential for commercial or privacy reasons, or are extensively aggregated at the level of national or regional statistics, with restricted metadata. Therefore, due to the lack of heat meters and the limited availability of smart meter data from the UK's domestic buildings on a large scale, there are gaps in previous studies related to empirical investigations of high-resolution heat load profiles, and therefore regarding the phenomenon of diversity during peak domestic heat demand.

3.2.2 Energy demand diversity and after diversity maximum demand

Studies have been conducted to calculate and predict domestic electricity load diversity since the 1930s (Bary, 1945). The diversity factor was introduced as an index that offers insight regarding the probability that one household will consume energy coincidentally to another. It is defined in Equation (3.1) as: ‘the ratio of the sum of the individual non-coincident maximum demands of various subdivisions of the system to the maximum demand of the complete system’ (IEEE, 1994). It measures the extent to which load profiles for individual loads interleave, with the peak(s) in the nth load falling to a greater or lesser extent into the trough(s) in the aggregate of the preceding n-1 loads.

The diversity factor is never less than one. The higher the diversity factor, the lower the probability that the energy demands of households will peak simultaneously. Some studies use the term ‘coincident factor’ or ‘coincidence’, which is the reciprocal of the diversity factor, as shown in Equation (3.2), and has a value between zero and one.

$$Diversity\ factor\ = \frac{\sum Individual\ maximum\ demand}{maximum\ demand\ of\ the\ aggregated\ system} \tag{3.1}$$

$$Coincident\ factor = \frac{1}{Diversity\ factor} \tag{3.2}$$

The after diversity maximum demand (ADMD) considers diversity between customers, and it has been used to design electricity distribution systems where demand is aggregated across a group of customers (Boggis, 1953; Seneviratne, 2013; Barteczko-Hibbert, 2015). It represents the diversified peak demand per customer with respect to the number of customers connected to the network. As shown in Equation (3.3), the ADMD per customer is calculated as the aggregated maximum demand at a given time within a group of dwellings (MD_i), divided by the number of dwellings (N). The ADMD per customer decreases due to the diversity effect when the number of customers connected to the network increases, and it becomes stable when the number of customers approaches infinity. Nonetheless, the ADMD per customer is not necessarily a monotonically decreasing function of the number of customers in the system (Poursharif, 2018).

$$ADMD\ per\ customer = \lim_{N\to\infty} \frac{1}{N} \sum_{i=1}^{N} MD_i \tag{3.3}$$

The diversity factor and ADMD can be used to determine the sizing of any energy supply or conversion system, including electrical wires or district heating pipes and substations. Willis (2004) suggested that a homogenous group of more than 100 customers would be sufficient for estimating an accurate ADMD value for electricity distribution. However, there is a lack of literature concerning the number of customers needed to accurately assess the ADMD for heat distribution based on empirical evidence.

Different methods have been used to model electricity loads and ADMD for forecasting maximum electricity demand on district energy networks, such as Monte Carlo simulations (McQueen et al., 2004; Boait et al., 2015). Some studies have had high resolutions to simulate multi-energy demand profiles in the UK (Good et al., 2015; McKenna and Thomson, 2016). Richardson et al. (2010) and Jenkins et al. (2014) developed models to compare synthesised electricity demand profiles and ADMD with measured data in dwellings and substations. Both studies demonstrated the value of studying energy load profiles and diversity for planning local electricity distribution networks, forecasting future demand, and integrating future technologies.

Furthermore, Elombo et al. (2017) studied mixed models and monitored residential electricity load profiles in order to inspect ADMD variations, based on different sampling periods and aggregation scales of up to 60 homes. They concluded that the variance of electricity load decreased as the sampling resolution was reduced, and the aggregation level increased. Nevertheless, modelling studies face challenges in terms of capturing the stochastic nature of energy consumption across a large number of households.

Some studies have attempted to measure and describe electricity demand diversity through empirical data. Barteczko-Hibbert (2015) and Sun et al. (2016) computed domestic electricity ADMD per customer according to different demographic groups using smart meter data. They proposed that both the electricity ADMD per dwelling and the uncertainty decrease in general as the number of dwellings increases, with the final ADMD stabilising below 2 kW per dwelling. Barteczko-Hibbert (2015) also stated that electricity ADMD was higher in customer groups with higher incomes or electric vehicles. Similarly, Summerfield et al. (2007) found higher energy use in larger dwellings with higher incomes through analysing monitored hourly temperature and energy consumption in gas centrally heated ‘low-energy’ dwellings in Milton Keynes, UK.

Furthermore, Love et al. (2017) studied the ADMD for electric heat pumps using monitored electricity consumption data pertaining to roughly 700 heat pumps in the UK. They found that the ADMD per heat pump decreased by about 57% from 4 kW to 1.7 kW, and reached towards its asymptotic value (to within two decimal points) at 275 heat pumps. Nevertheless, the paper only dealt with the ADMD for electricity demand from electric heat pumps, as opposed to the ADMD for heat demand from households. Further studies are needed to assess diversity in domestic heat demand using measure energy demand data.

Although there is no universal standard to quantify the diversity factor and ADMD for residential heat demand in the UK, several standards have been introduced to characterise the diversity effect in different countries for different purposes, including sizing the heat exchanger capacities, hot water pipes, and district heating hot water flow rates. Different standards have applied different input factors or assumptions to calculate diversity factors, such as the number of occupants, dwellings, or hot water flow rates. For example, the MTA2016 is used in France and suggests that the coincident factor of domestic hot water demand drops from 1.0 to 0.125 when the number of apartments increases from 1 to 14 (COSTIC, 2016). After adapting the codes of practice for drinking water installations and assuming all residential units are standardised, the DIN 4708 and the DIN 1988-300 are used to calculate residential hot water demand, size district heating pipes and determine the peak flow rates for domestic hot water supplies in Germany (NAW, 2012).

Moreover, the Danish Standard DS439 (Dansk Standard, 2009) is the most commonly used standard in the district heating sector. The DS439 is used for both cold and hot water services in Denmark. It is used to size the heat exchanger for domestic hot water supplies based on ‘the number of normal apartments (or a standard property)’, and it has been adopted as the standard diversity curve to size heat generation. The DS439 was preferred by the CIBSE’s heat network Code of Practice (CIBSE and ADE, 2015) to design and develop district heating in the UK.

Meanwhile, the Swedish District Heating Association (SDHA, 2004) suggested a heat power diversity curve (the DHA F:101 standard) based on the domestic hot water flow rates (litres per second) and the designed temperatures at the taps for different types of dwellings. This standard has been used as a regulation for Swedish district heating networks to design, install, and maintain substations in order to keep the temperature of domestic hot water at the taps above 50 ℃. Nevertheless, neither the DS439 nor the DHA F:101 considers residential space heating demand.

Furthermore, Cosic (2017) argued that it is uncommon to use an instantaneous heat exchanger to serve a large number of dwellings with domestic hot water only in Denmark, and that the DS439 curve is old, predating the arrival of low-flow water fixtures. This report (Cosic, 2017) also stated that ‘consultants specify large peak hot water loads for individual dwellings, scales these reference curves, and claim that the resulting designs are “designed in accordance DS439” or similar. This is untrue – such calculations are their own work not a nationally accepted standard.’

Additionally, Hanson-Graville (2018) pointed out that the application of the DS439 has never been formally evaluated for British dwellings, and the diversity effect of heat demand in UK dwellings is not thoroughly understood. Although the DS439 is recommended by CIBSE and ADE (2015) to calculate the diversity of heat demand for the UK's district heating networks, a standard derived from primary data from a more relevant sample of dwellings is desirable to improve the understanding of the actual residential heat demand diversity in the UK.

A recently updated version of the heat network Code of Practice (CIBSE, 2020) stated that 'if time permits and it is appropriate, peak demands should be determined by monitoring the heat currently supplied to the building or its fuel use, under external design conditions using existing or temporary meters and recording data at hourly or half-hourly intervals.' Accurate heat measurements are essential for efficaciously assessing the performance of heating technologies. It is also emphasised that the diversity is significant and must be applied to prevent oversizing of district heating distribution pipework (CIBSE, 2020).

However, metered heat consumption data are scarcer than metered electricity data in the UK, due to the predominant market share of individual gas boilers and limited deployment of heat meters. The market data for heat meters are scarce, and sometimes contradictory statistics are reported by different sources (BEIS, 2016b). Additionally, there are sociotechnical challenges regarding the rollout of individual heat metering in the UK (Morgenstern et al., 2015).

Understanding energy demand heterogeneity arising from end users and technical systems in buildings is fundamental for evaluating energy supply technologies, and for designing cost-effective strategies to meet demand. This study obtained empirical electricity and gas consumption data with metadata from the largest smart meter field trial in the UK, and utilised gas consumption data as a proxy to offer insight into heat demand and diversity in residential buildings when a certain number of dwellings are aggregated. Moreover, this chapter analyses data from the domestic heat pump field trial to illustrate heat load profiles from dwellings with individual heat pumps. This chapter presents the shape of the aggregated energy load profiles according to external temperatures over a period of one year. It also offers an empirical understanding of peak energy consumption during cold weather conditions, and quantifies diversity and scaling effects as the number of households increases. Results from this chapter can be applied, with caution, to district energy design and planning, and to designing evidence-based market strategies and energy policy objectives.

3.3 Methodology

This section demonstrates approaches to acquiring and selecting datasets and data, as well as the research tools and methods used to address the first subsidiary research question. The flow diagram (Figure 3.4) at the end of Section 3.3.1 (page 94) illustrates an overview framework that summarises the procedures conducted for data storage, acquisition, extraction and management.

3.3.1 Datasets

Four main datasets are employed and analysed for the first subsidiary research question in this chapter to investigate empirical energy demand in British dwellings:

- Residential electricity and gas smart meter data from the Energy Demand Research Project (EDRP) smart meter field trials.
- Residential electricity and gas smart meter data from the EDF subset of the EDRP dataset.
- Geospatial and weather data from the Met Office.
- Electricity and heat metering data from the Renewable Heat Premium Payment (RHPP) datasets.

3.3.1.1 The Energy Demand Research Project (EDRP) data and its EDF subset data

Time series energy consumption data from the EDRP smart meter field trials are the primary datasets used in this study to analyse residential energy load profiles and energy demand diversity. The EDRP project was a set of large scale field trials in Great Britain, founded by the government and led by energy suppliers to investigate consumers' responses to different forms of information and interventions about their energy consumption (Ofgem, 2019a). Ofgem oversaw the field trials, which involved 61,344 households recruited by four energy companies: EDF Energy Customers Plc, E.ON UK Plc, Scottish Power Energy Retail Ltd, and SSE Energy Supply Ltd (AECOM, 2011).

The EDRP project began in June 2007 and finished towards the end of 2010, monitoring half-hourly energy consumption in a total of 18,370 households (Raw and Ross, 2011). The first generation of smart meters (Smart Meter Equipment Technical Specification, also known as SMETS1) were installed at individual dwellings, together with real-time display devices which show energy consumption. Raw data were centrally collected from the four companies, anonymised and managed by the Centre for Sustainable Energy (CSE), and an independent review of the field trials and data analysis were conducted by AECOM (UK Data Archive, 2014).

There are several versions of the EDRP datasets because the data collection and cleaning procedures are involved with multiple participating companies and organisations. The EDRP dataset managed by the CSE is the largest publicly available smart meter dataset in the UK. This dataset became available to the public in November 2014, and an updated edition of this dataset was released online in October 2018 after the implementation of the General Data Protection Regulation (GDPR) in the UK (AECOM, 2018).

Half-hourly electricity and gas consumption data (kWh) collected over the period of 8th January 2008 to 30th September 2010 were made publicly available by the UK Data Service (AECOM, 2018). According to this edition, smart meter data from 14,598 households were published, of which 8942 households had duel fuels, 5650 had only electricity, and six had only gas. After the removal of colliding records and anonymisation processes under the guidance provided by the Information Commissioner's Office (ICO) Code of Practice, approximately 246 million and 412 million of the gas and electricity meter readings from the 14,598 households were consolidated into a single database, stored as CSV files and made accessible through the UK Data Service (AECOM, 2018).

The UK Data Service also published the metadata for the EDRP dataset with anonymised household IDs (AECOM, 2018). The metadata provides information regarding the occupants' statuses based on Acorn classifications, which are six categories, 18 groups and 62 types of geodemographic segmentation of the UK's population based on a range of factors such as postcodes, occupations, lifestyles, races, and financial circumstances (Acorn, 2014). The EDRP metadata includes 57 types of households under Acorn classifications, for example, 'families and single parents, council flats', 'home owning Asian family areas', and 'wealthy mature professionals, large houses' (AECOM, 2018).

The metadata provides a coarse level of details about occupants; however, it does not always specify the dwelling types and ages. Moreover, the identifiable locations of the field trial households were removed, and all the monitored dwellings were classified into 406 areas by the Nomenclature of Territorial Units for Statistics (NUTS) IV and local administrative units (LAUs) codes. As a result, it is difficult to completely categorise the monitored households based on their dwelling locations, types and ages. A comparison between different versions of the EDRP data can be found in Appendix A.1.

Figure 3.1 displays the variations in sample sizes of electricity and gas consumption data from the publicly available EDRP dataset throughout the field trials between January 2008 and September 2010. The total number of electricity and gas readings changed throughout the field trials because the monitored households joined the field trials at different times, and there were a number of occurrences of missing data at various periods of time among a large proportion of the monitored households. However, there were no explanations regarding the data gaps from the metadata or the dataset's accompanying documents.

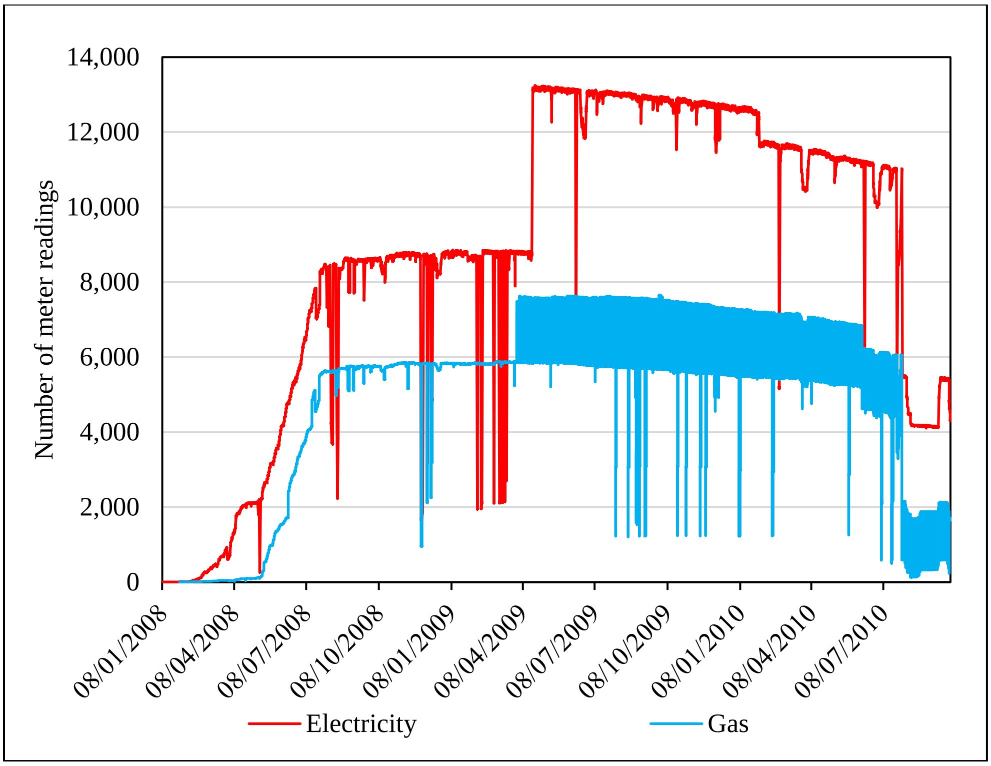

Figure 3.1: Sample sizes of half-hourly smart meter data between January 2008 and September 2010 during the whole EDRP field trials.

The half-hourly electricity sample size of the EDRP dataset increased from one to more than 8,500 within eight months after the trials started. Meanwhile, the half-hourly gas sample size grew from one to more than 5,500. The sample size of half-hourly electricity readings became relatively stable from the beginning of August 2008 towards mid-April 2009. It then increased dramatically to more than 13,000 before it declined steadily until late July/early August, when the number suddenly dropped from more than 11,000 to just above 4,000. The number slighted rebounded to under 5,500 around mid-September 2010. In terms of the sample size of gas readings, the number oscillated between around 6,000 and 7,500 from April 2009 to July 2010, and then it rapidly fell below 2,000 towards the end of the field trials.

Besides the whole EDRP field trial dataset, a subset of the EDRP dataset was obtained for this study from one of the four participating energy companies, EDF Energy Customers Plc (the EDF subset). EDF Energy stored the raw EDRP data and its own subset on the purpose-built database by Amazon Web Services (AWS), which is called the Simple Storage

Service (S3) bucket (AWS, 2019). Data access was granted for this study by EDF Energy, and the datasets were recovered using a Python script from the AWS S3 bucket and managed in PostgreSQL (accessed by pgAdmin). This dataset contains half-hourly smart meter data from 18,370 households, plus a subset of monitored electricity and gas consumption from 1,879 dwellings in England between 8th January 2008 and 26th October 2010. Unlike the metadata of the whole EDRP dataset, the metadata of the EDF subset contained very detailed information regarding the 1,879 monitored households, including dwelling ages, types, ownerships, numbers of rooms, postcodes, and occupants' demographic details.

Although all households from the EDF subset were documented with randomly generated arbitrary integers from 1 to 99,999, a set of further anonymisation actions were taken to ensure that the individual dwellings became unidentifiable during the data extraction process. All data which could potentially identify any specific households were removed. Accordingly, this study only extracted anonymised households' IDs, monitored smart meter data, 3-digit postcodes, times of meter readings, dwelling types and age groups, types of energy tariffs, and main heating technologies.

Figure 3.2 shows the variations in sample sizes of electricity and gas consumption data from the EDF subset dataset. Both electricity and gas sample sizes increased steadily during the first year of the field trials, starting with two households on 8th January 2008. The numbers of half-hourly electricity and gas data reached around 1,200 and 400 respectively in January 2009, and the maximum number of metered readings exceeded 1460 in October 2009. Then the figures dropped significantly after mid-August 2010 towards the end of the field trials. Similar to the whole EDRP dataset, the EDF subset shows that there were occasions when both electricity and gas data were missing. Although no published documents from EDF Energy discussed this issue, ELEXON (2012) conducted interviews with EDF Energy and proposed that one of the possible reasons for this was that the data gaps were caused by smart meters and data storage maintenance.

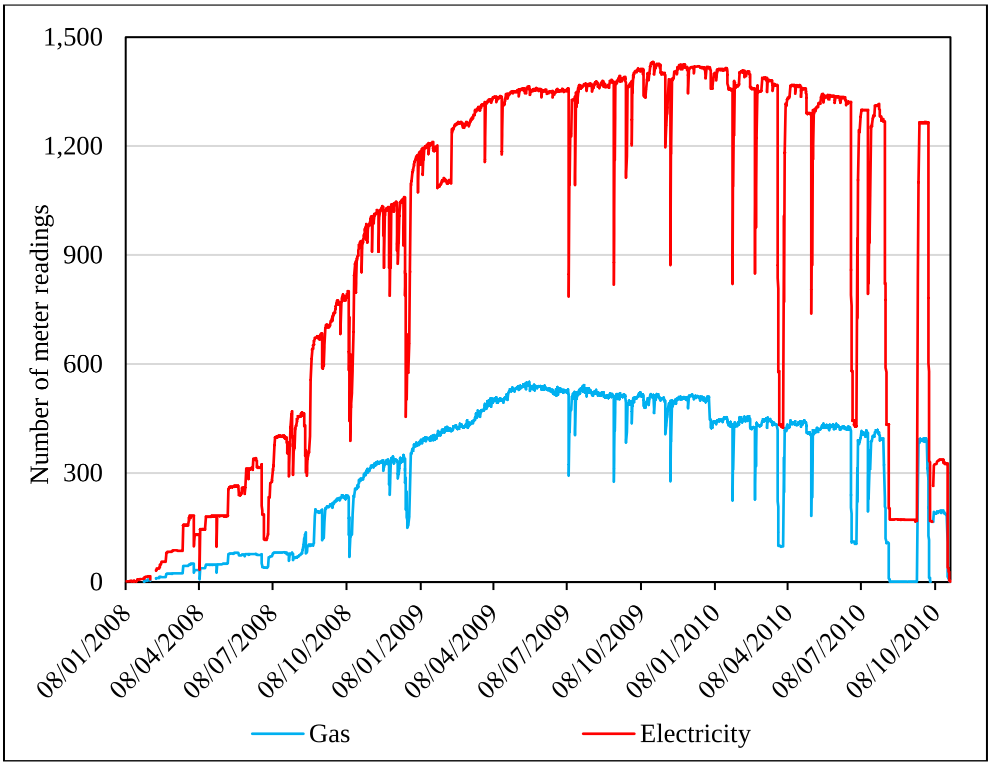

Figure 3.2: Sample sizes of half-hourly smart meter data of the EDF subset between January 2008 and October 2010.

3.3.1.2 The Renewable Heat Premium Payment (RHPP) data

Besides smart meter data, monitored data from individual heat pumps were used for this research. The data were collected through the RHPP scheme, which was a government funded programme to encourage households to install domestic renewable heating systems by offering one-off grants. The RHPP provided subsidies to install over 14,000 heat pumps over the period from August 2011 to March 2014 (Lowe et al., 2017), and it was then replaced by the Renewable Heat Incentive (RHI) (Ofgem, 2019b). Different from the RHPP, the RHI provides quarterly payments to households based on the amount of renewable heat generated over a period of seven years (BEIS, 2019a). Monitored data from about 700 domestic heat pumps during the RHPP field trials were collected by the Buildings Research Establishment (BRE) and analysed by Lowe et al. (2017) in order to evaluate their performance, including ground source heat pumps and air source heat pumps from a range of dwelling types across Britain.

A cleaned version (Sample B2) of the RHPP dataset from 418 sites, which was made publicly available by Lowe et al. (2017), contains monitored data over a period of at least 12 consecutive months from 319 air source heat pumps and 99 ground source heat pumps (UK Data Service, 2017). The RHPP Sample B2 dataset was obtained for this research to study energy load profiles from domestic heat pumps, with electricity and heat data monitored from 2nd February 2012 to 1st April 2014. This dataset contains monitored data from individual heat pumps at 2-minute intervals, including electricity consumption, heat generation, water flow rates, and temperatures. Moreover, the dataset was accompanied by a metadata file providing information regarding monitored households and heat pumps, such as site schematics, installed heat pump capacities, and dwelling types.

3.3.1.3 The Met Office weather data

After the anonymisation processes of the EDRP smart meter field trials, it is impossible to find the exact locations of individual dwellings and acquire onsite monitored weather data or historical weather data from their closest weather stations. Modelled location-based (estimated to the first three digits of postcodes) historical hourly external weather data were used for this research to investigate the relationships between residential energy consumption and external temperatures.

Furthermore, during the EDRP field trials, the UK experienced two remarkably cold winters. According to meteorological records, winter 2008/2009 was the coldest winter since 1996/1997 (Met Office, 2013), and the widespread and prolonged cold spells made winter 2009/2010 the coldest winter since 1978/1979 (The Guardian, 2010), and the seventh coldest winter since 1910 in the UK (Prior and Kendon, 2011). This provides opportunities to study energy load profiles and peak demand during particularly cold weather events.

This research obtained the weather data from Chambers (2017), who constructed a dataset containing time series GIS-based weather data across the British Isles based on two Met Office data sources: the Numerical Weather Prediction (NWP) datasets and the NCEP Climate Forecast System Reanalysis (CFSR) datasets. Originally, the NWP data were weather and climate forecasting data drawn from the Met Office European Atmospheric Hi-Res Model (Met Office, 2017), and the data have been harmonised with hourly observation data through the Met Office Integrated Data Archive System since 2008 (Met Office and CEDA, 2019a). Whereas, the CFSR collected global weather data between 1979 and 2010 by in situ and satellite observations (Saha et al., 2010).

The weather data were linked with hourly energy consumption data monitored by smart meters for each individual dwelling based on their postcodes. Accessing, managing and linking both of the datasets required intensive computing power. Chambers (2017) connected the geospatial and gridded weather datasets to generate a GIS-based hourly weather dataset for the UK using the Legion High Performance Computing platform. The processed weather dataset contains a set of hourly meteorological data, including external air temperature, relative humidity, air pressure, precipitation and wind speed for 1,879 dwellings from the EDF subset (Chambers, 2017). The hourly external air temperatures at surface level with a spatial resolution of approximately 0.04° (4 km) were used, and only hourly external air temperature data from 8th January 2008 to 26th October 2010 were extracted for the purpose of this research. Figure 3.3 shows the hourly average external temperatures among the number of monitored dwellings from the EDF subset of the EDRP throughout the field trials.

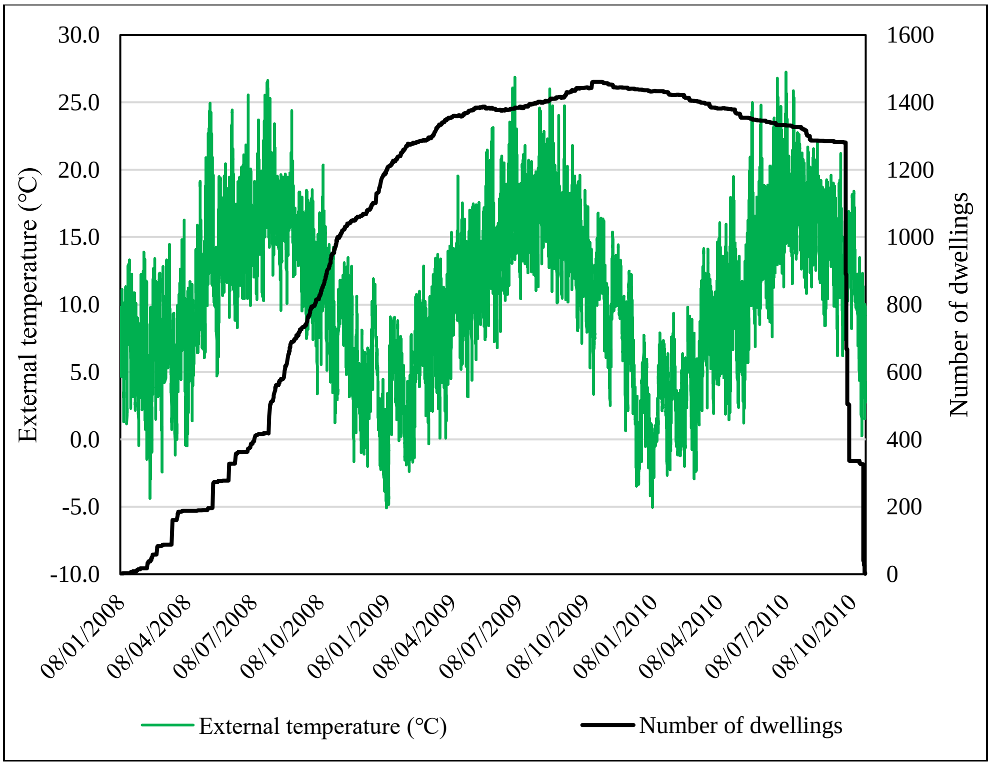

Figure 3.3: Hourly external temperatures and numbers of dwellings during the EDRP EDF field trials, data from Chambers (2017).

Figure 3.4 illustrates an overview framework that summarises the four main datasets for this chapter. It also shows platforms, tools, and procedures conducted for data storage, access, acquisition, extraction, and management.

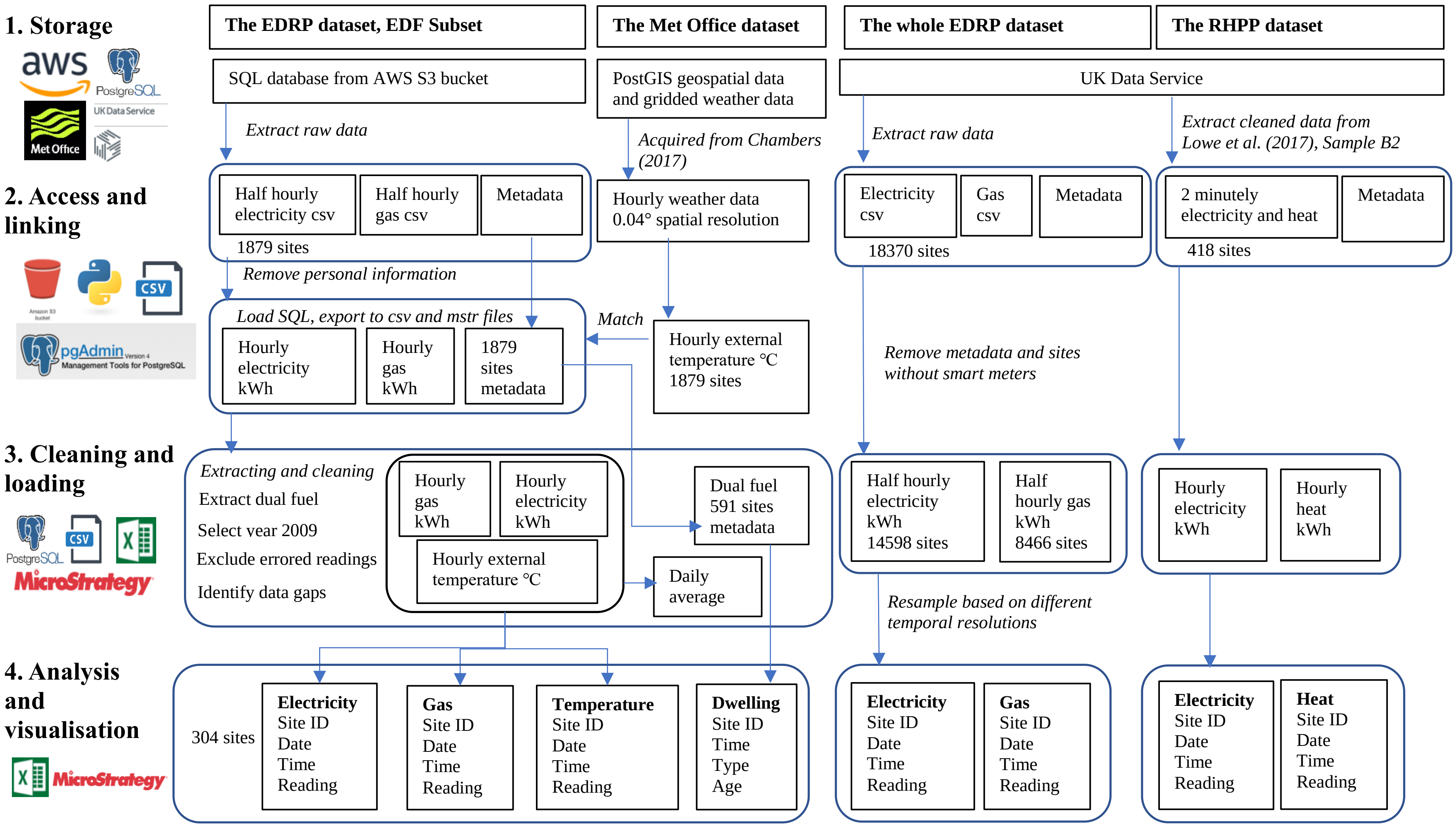

Figure 3.4: A framework that summaries the procedures conducted for data acquisition and management.

3.3.2 Data analysis

Linking and loading data systematically is challenging when there is a large amount of data from different datasets with different formats. This research uses a set of tools to access and manage the raw datasets from different data storage systems. After being downloaded from the UK Data Service (UK Data Archive) and the AWS S3 bucket, energy consumption data from the EDRP field trials and its EDF subset were recovered by Python and managed in pgAdmin (PostgreSQL), and then exported to CSV files. Weather data were originally in H5 format and were also transformed into CSV files. Data from the RHPP Sample B2 were downloaded from the UK Data Service in their original format (CSV).

All data were loaded into MicroStrategy and prepared for data cleaning, extraction and analysis. MicroStrategy (2019) is an enterprise business intelligence (BI) analytics platform which is able to connect, process and visualise big data quickly from multiple sources simultaneously. Half-hourly smart meter data from the EDF subset were resampled into hourly data in order to link with the hourly external air temperature data for individual households based on their postcodes. The cleaned data, results and figures were exported in Microsoft Excel.

Energy consumption data from the EDRP field trials were extracted, resampled, and analysed to explore energy load profiles, as well as to study winter peak hourly demand and ADMD in 2009, because winter 2009/2010 was one of the coldest in Britain over the last three decades. The whole EDRP dataset was used to construct the load profiles from 1st June 2009 to 31st May 2009, which covered an entire heating season, and the EDF subset and the Met Office data were used to study the load profiles throughout the 8760 hours in 2009. Moreover, monitored two-minutely data from the RHPP were resampled into hourly data in order to compare the load profiles for individual electric heat pumps with those for individual gas boilers from the EDRP field trials. Then, normalised load profiles were constructed to compare the consumption patterns of electric heat pumps with those of gas boilers.

In addition, in the absence of heat meters, and where gas boilers were the most popular heating measures in the UK (BEIS, 2018a), this study uses natural gas consumption data as a proxy for representing heat demand. Gas is also commonly used for cooking, and many households in the UK have gas hobs, ovens or grills installed. However, according to government statistics, gas for cooking only has contributed between 1.8% and 2.6% to the total residential gas demand over the last two decades (BEIS, 2018b). Furthermore, gas consumed for cooking is eventually converted to heat. Hence, this research believes that gas consumption is an appropriate proxy to study residential heat demand at the aggregated levels where heat loads are not measured by heat meters.

Figure 3.5 provides a summary of the selection and analysis procedures of smart meter data from the field trials. This research aims to study not only energy consumption, but also the differences in aggregated peak energy demand when the number of dwellings increases. The whole EDRP dataset was used to calculate the peak and average annual electricity and gas consumption per dwelling, as well as the impact of different temporal sampling frequencies on the peak demand. Furthermore, because households in the EDRP field trials have different heating measures and monitoring periods, the main analysis of this study focuses on EDF Energy's subset of dwellings for which high-quality monitored energy consumption data and metadata were available on dwelling types, ages and primary heating technologies.

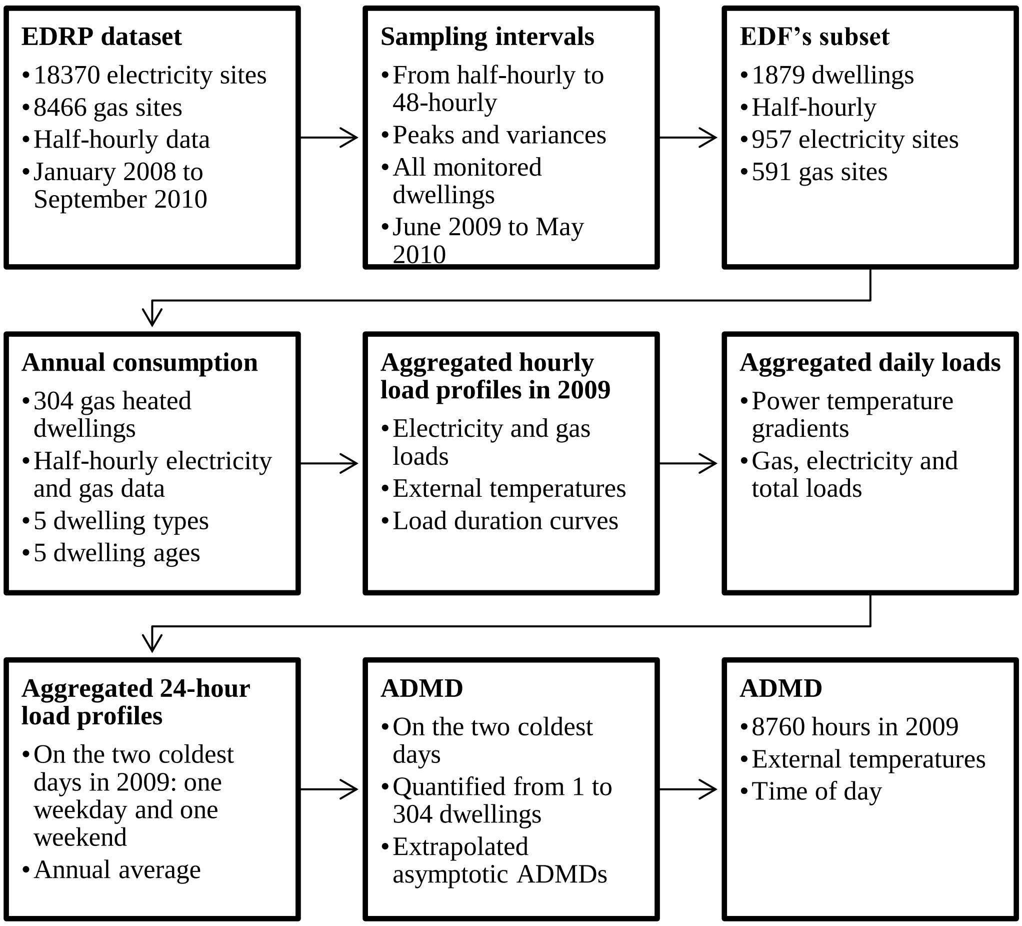

Figure 3.5: An overview of data selection and analysis for the smart meter data.

Following data selection and extraction processes under four conditions, smart meter data from a total of 304 households were obtained:

- there were metadata related to the types and ages of dwellings;
- the selected dwellings' monitoring periods included the entire year of 2009;
- both electricity and gas were monitored on a half-hourly basis;
- selected households used gas boilers as the primary heating systems to meet their domestic heat demands.

After energy consumption data from 304 dwellings were extracted, hourly external air temperature data (Met Office, 2017; Chambers, 2018) were assembled for the sampled dwellings. Energy consumption throughout 2009 was averaged according to the different types and ages of dwellings. Then, the selected electricity and gas consumption data were resampled and aggregated across all 304 dwellings to construct the hourly electricity and gas load profiles, in order to match hourly external temperatures.

After comparing the load profiles across the seven days of the week and the two hottest days in 2009, the two coldest days (one weekday, and one weekend) were identified based on both daily average and hourly minimum external temperatures; 24-hour load profiles were constructed to study the shapes of hourly load profiles on the two coldest days. Meanwhile, the aggregated daily electricity and gas consumptions were plotted against the aggregated daily external temperatures to study changes in energy demand in response to changes in external temperatures.

The diversified hourly maximum electricity and gas demand (ADMD) per dwelling, and how this changed when the number of households increased, was further analysed for the two coldest days in 2009, according to Equation (3.3). A random sampling approach was applied to selected dwellings, with ADMD recalculated after the addition of each dwelling, from one to 304 (293 for gas ADMD on Saturday due to data errors in 11 dwellings). This process was repeated for 50 trials on each day to examine the mean of ADMD. Then, the results from 304 dwellings were extrapolated to estimate electricity and gas ADMDs per dwelling when the number of dwellings approaches infinity. After electricity and gas ADMDs were quantified for the two coldest days in 2009, data monitored throughout 2009 were scrutinised to identify the external temperature and time of day when the ADMD occurred, in order to test whether the diversified peak energy demand always happens during the coldest weather conditions. Additionally, gas load profiles from the EDRP field trials and heat pump load profiles from the RHPP field trials are compared.

3.4 Results and discussions

3.4.1 Sampling intervals and their impact on peak energy loads

Temporal sampling frequency is an important feature which could affect the peak energy demand (Sajjad et al., 2014). The term temporal sampling of energy means the averaging energy load data over a certain period of time, such as hourly or daily, in the context that the cumulative energy consumption is recorded by a smart meter. A series of sampling time intervals, from half-hourly to 48-hourly, were applied to quantify the peak gas and electricity loads per dwelling. Due to data availability, this study does not investigate frequencies lower than half-hourly. Gas and electricity smart meter data from 1st June 2009 to 31st May 2010 were extracted to calculate the average gas and electricity consumption per dwelling, covering the winter heating season in 2009/2010.

The results found that the average annual gas consumption was 17,880 kWh per dwelling (from 8,466 monitored dwellings), which was almost four times higher than the average annual electricity consumption, accounting for 4,490 kWh per dwelling (from 14,598 monitored dwellings). Meanwhile, Figures 3.6 to 3.9 demonstrate different load profiles over a year and the changes in peak energy loads and the sample variances at an aggregated level when the temporal sampling frequency was changed from half-hourly to longer time intervals. These figures show that the peak energy loads did not change expressively when the sampling time interval increased from half-hourly to hourly. In contrast, as expected and shown in Figure 3.6 and Figure 3.7, when the sampling time interval increased from hourly to 48-hourly, the peak loads dropped considerably.

As shown in Figures Figure 3.6 to Figure 3.8, the monitored half-hourly gas (averaged from 8,466 monitored dwellings) and electricity (averaged from 14,598 monitored dwellings) loads peaked at approximately 8.0 kW and 1.2 kW per dwelling in winter 2009/2010. The peak gas and electricity loads only decreased by 0.4% and 1.2%, respectively, when the sampling time interval increased from half-hourly to hourly. However, the winter peak gas and electricity loads dropped by more than 33% and 37% when the sampling interval became longer than 24 hours, and the peak gas and electricity loads reached around 5.3 kW and 0.8 kW per dwelling when the sampling time interval was 48-hourly. This suggests that there are significant 24-hour cycles in domestic energy consumption.

Furthermore, Figure 3.9 shows that averaging of energy consumption over progressively longer intervals of time progressively reduces the variance (the squared deviation of a variable from the mean value). The sample variance decreased by over 47% (gas) and 74% (electricity) when the sampling time interval increased from half an hour to more than 24 hours. Therefore, half-hourly and hourly data might be more suitable than data with longer sampling time intervals to study peak energy loads. This study utilises hourly energy consumption data, due to the lack of half-hourly external air temperature data.

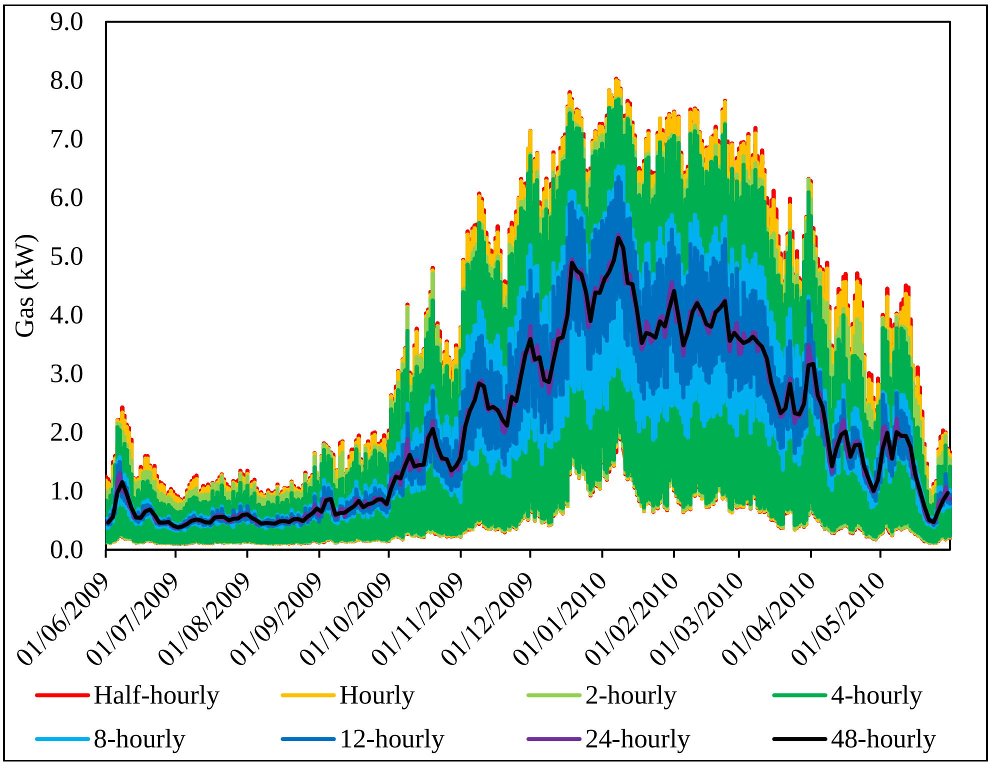

Figure 3.6: Gas load profiles based on different temporal sampling frequencies between 1st June 2009 and 31st May 2010.

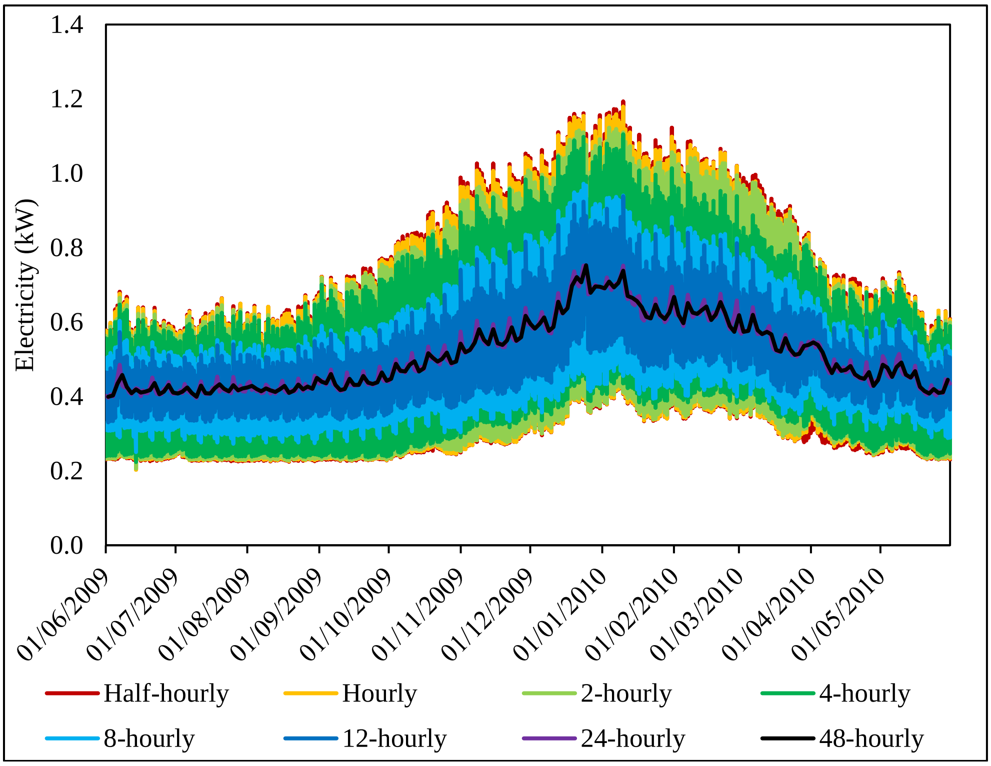

Figure 3.7: Electricity load profiles based on different temporal sampling frequencies between 1st June 2009 and 31st May 2010.

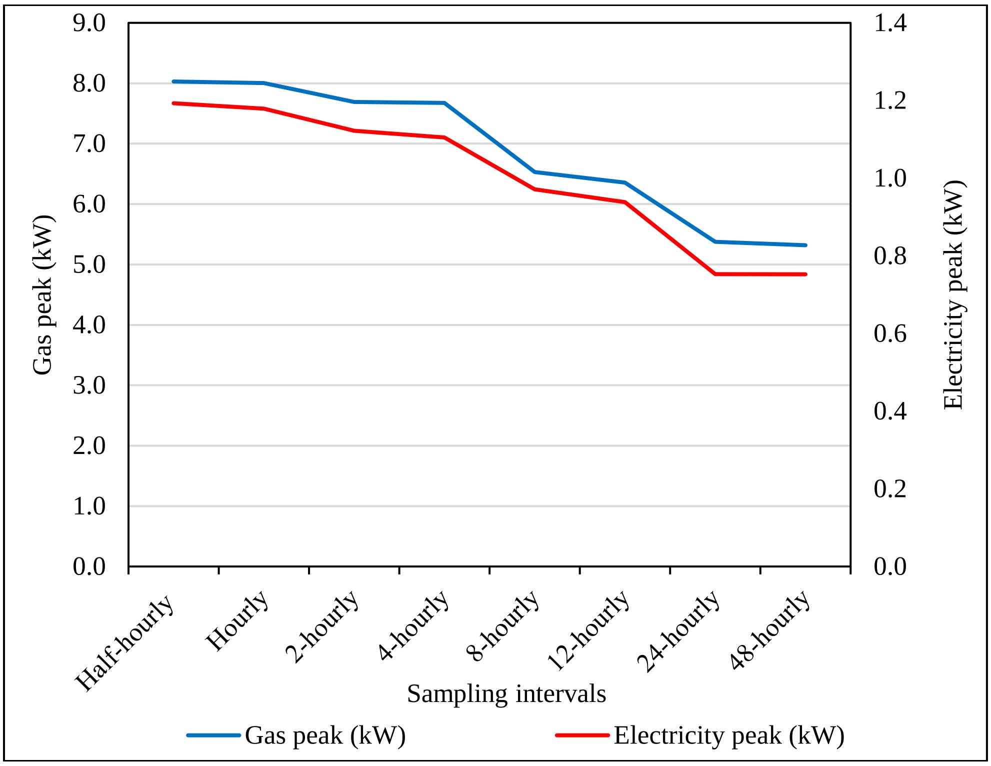

Figure 3.8: Impact of temporal sampling frequencies on the aggregated peak gas and electricity loads.

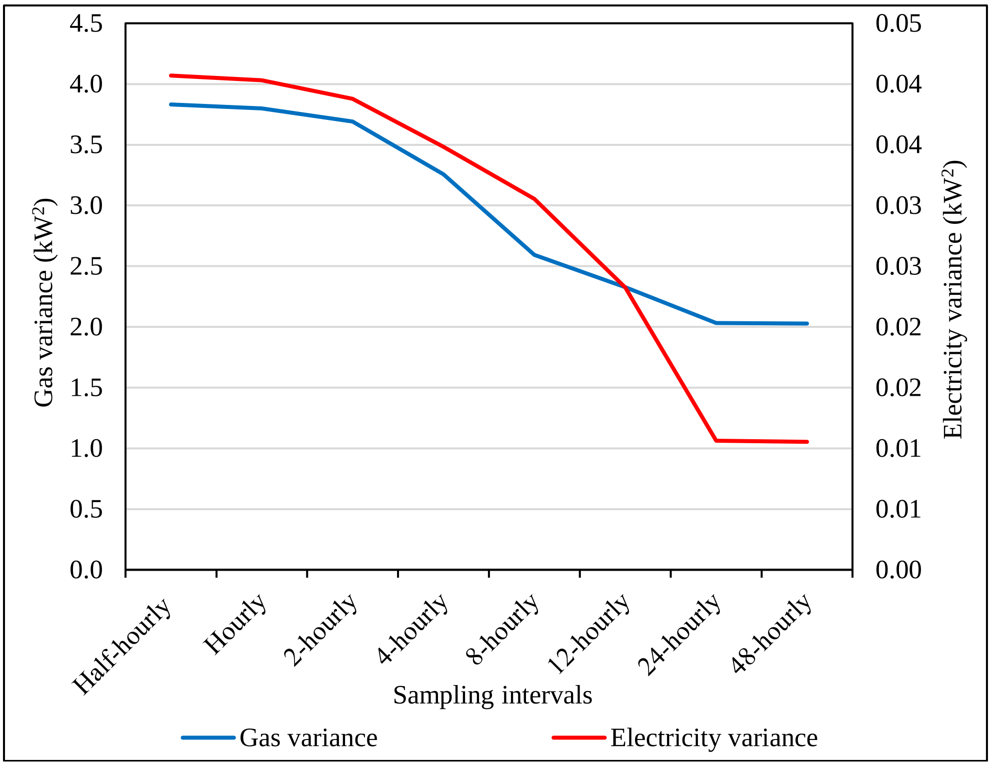

Figure 3.9: Impact of temporal sampling frequencies on the aggregated peak gas and electricity variances.

3.4.2 Annual consumption and load profiles in different ages and types of dwellings

Table 3.1 illustrates the monitored electricity and gas consumption for different types and ages of dwelling in 2009 based on smart meter data and metadata from the subset of 304 gas centrally heated dwellings during the EDF field trials. As expected, the newer the dwelling, the lower the annual gas consumption tends to be, with below 15,000 kWh of gas required in dwellings built after 1980, whereas the annual gas consumption for dwellings built before 1919 was about 23,800 kWh. The annual electricity and gas consumption for a detached house was the highest of all dwelling types, accounting for over 5,300 kWh of electricity and 23,000 kWh of gas. This is because of the five main dwelling types in the UK, detached houses lack shared elements such as party walls and tend to be larger. In contrast, a flat consumed only around 3,000 kWh of electricity and less than 13,000 kWh of gas on average. However, 2009 was an unusually cold year, and due to limited occupant information and the absence of floor area measurements for the sampled households, these results may not be representative of typical domestic annual energy consumption in the whole UK.

Table 3.1: Annual gas and electricity consumption in different types and ages of dwellings.

Dwelling age	**Before1919**	**1919-1944**	**1945-1964**	**1965-1980**	**After1980**
Gas (kWh)	23764	21699	18745	16278	14937
Electricity (kWh)	4821	5294	4933	4199	4417
Dwelling type	**Detached**	**Semi-detached**	**Terraced**	**Bungalow**	**Flat**
Gas (kWh)	23142	18859	16909	17804	12938
Electricity (kWh)	5306	5283	4089	4304	3019

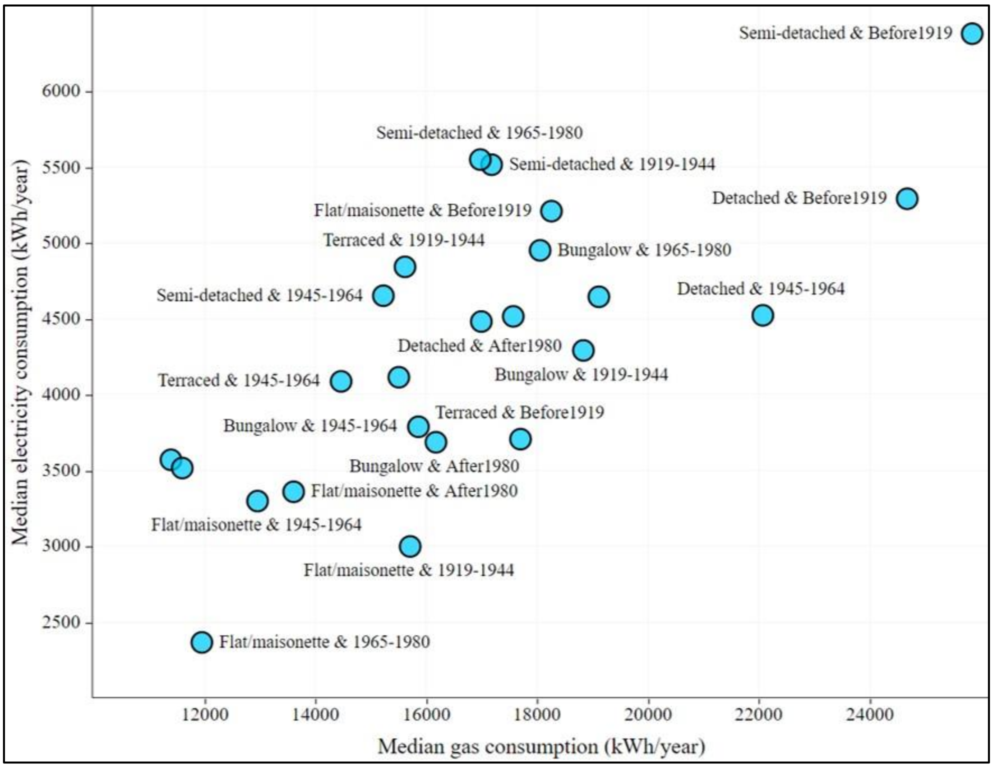

Figure 3.10: Median annual electricity and gas consumption from different types and ages of dwellings.

Besides energy consumption of five types or ages of dwellings, Figure 3.10 compares the median annual electricity and gas consumption based on different combinations of dwelling type and age groups from the sampled 304 dwellings. The figure illustrates diverse energy consumption from 24 different combinations of dwelling types and ages (there is no result of Bungalow & Before1919 because of no available data in the EDF subset of the EDRP dataset). Although there is no data to specify the size and thermal performance of these monitored dwellings from the EDRP dataset, the results found that older dwellings tend to have higher electricity and gas consumption. As Figure 3.10 indicates, a semi-detached house built before 1919 had the highest median electricity and gas consumption among all different dwelling type and age combinations, with median annual gas and electricity consumption reaching about 25,800 kWh and 6,400 kWh.

Moreover, Figure 3.10 not only shows a diverse range of energy consumption across different dwelling types and ages but also displays that energy consumption could be highly uncertain across the same dwelling type or age. Although energy demand may vary significantly according to different dwelling types and ages as shown in Table 3.1 and Figure 3.10, there are other important factors that may affect households' overall demand for electricity and gas, such as the conditions of building fabric insulation, the sizes and floor areas of the dwelling, and occupants' behaviours. However, these data were not available from the EDRP dataset.

Table 3.2: Descriptive statistics of electricity and gas consumption of the sampled 304 dwellings from the EDRP EDF subset.

Descriptive statistics	Gas	Electricity
Mean	17339	4839
Standard Error	383	149
Median	16681	4114
Mode	16983	5833
Standard Deviation	6676	2604
Sample Variance	44562805	6781126
Kurtosis	1.97	3.53
Skewness	1.15	1.70
Minimum	3319	1197
Maximum	43732	16460
Sample size	304	304

Furthermore, Table 3.2 summarises the descriptive statistics of electricity and gas consumption of the sampled 304 dwellings from the dataset. It also indicates how uncertain the annual energy consumption from a dwelling could be. For example, the average gas consumption among the studied dwellings was 17,339 kWh per year, but the range of annual consumption was from less than 3,400 kWh a year to almost 44,000 kWh a year, and the standard deviation could reach as high as ± 6,676 kWh (38.5% of the mean value). Additionally, detailed energy consumption data of the 24 combinations of dwelling types and ages are included in Appendix A.2 and Appendix A.3, with their sample sizes.

Figure 3.11 and Figure 3.12 illustrate daily gas and electricity load profiles throughout the year 2009, based on different dwelling ages and types. As shown in Figure 3.11, during the heating season, the newer the dwelling, the lower the daily gas load tends to be. For example, at the beginning of February 2009, the daily gas load for dwellings built before 1919 was over 7.5 kW, while the equivalent load for dwellings built after 1980 was below 5.0 kW. Furthermore, similarly to the variable annual consumption for different dwelling types, the daily gas load for detached houses surpassed 7.5 kW, whereas that for flats was less than 4.5 kW.

On the other hand, during the summer months between June and October, the daily gas loads were similar across all ages and types of dwellings, primarily due to the very low space heating demand during this period. As revealed in Figure 3.12, seasonality is the dominating factor that affects the energy loads in all types of dwellings. The daily gas loads for dwellings built before 1919 were slightly higher than other dwelling types, and the loads were well below 1.0 kW regardless of the type of dwelling, with the number fluctuating between 0.3 kW and 0.7 kW.

In comparison with the daily gas loads, Figure 3.12 demonstrates the daily electricity load profiles for different ages and types of dwellings in 2009. Unlike the daily gas load profiles, which exhibited strong seasonal fluctuations, the seasonal differences in daily electricity loads between various ages and types of dwellings appeared relatively small throughout the year. It is noticeable that the daily electricity loads for dwellings built before 1919 remained higher over the year as a whole, while those for flats were the lowest among all types of dwellings. Moreover, the daily electricity loads for flats were clearly lower than for other types of dwellings.

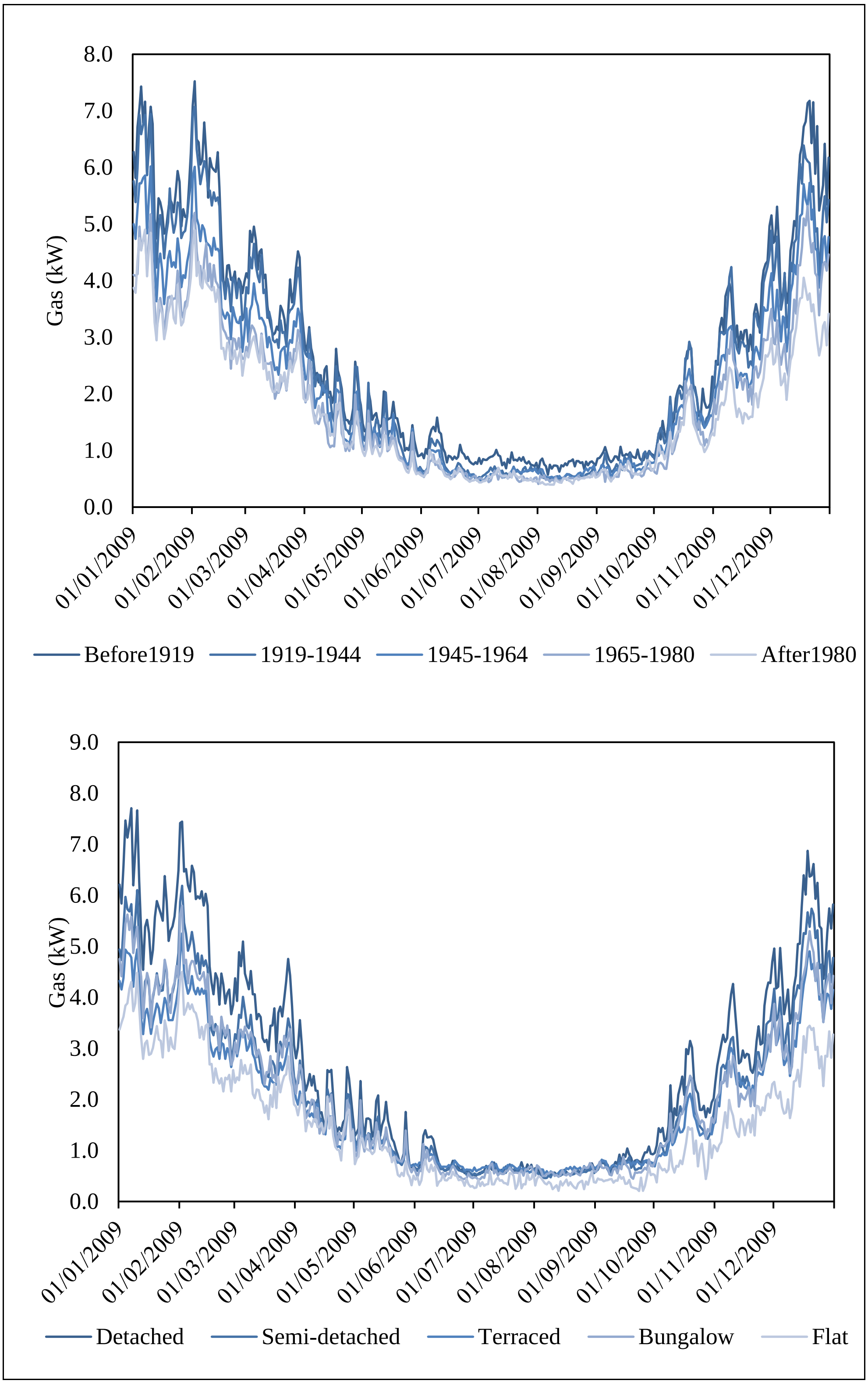

Figure 3.11: Daily gas load profiles of various dwelling ages and types.

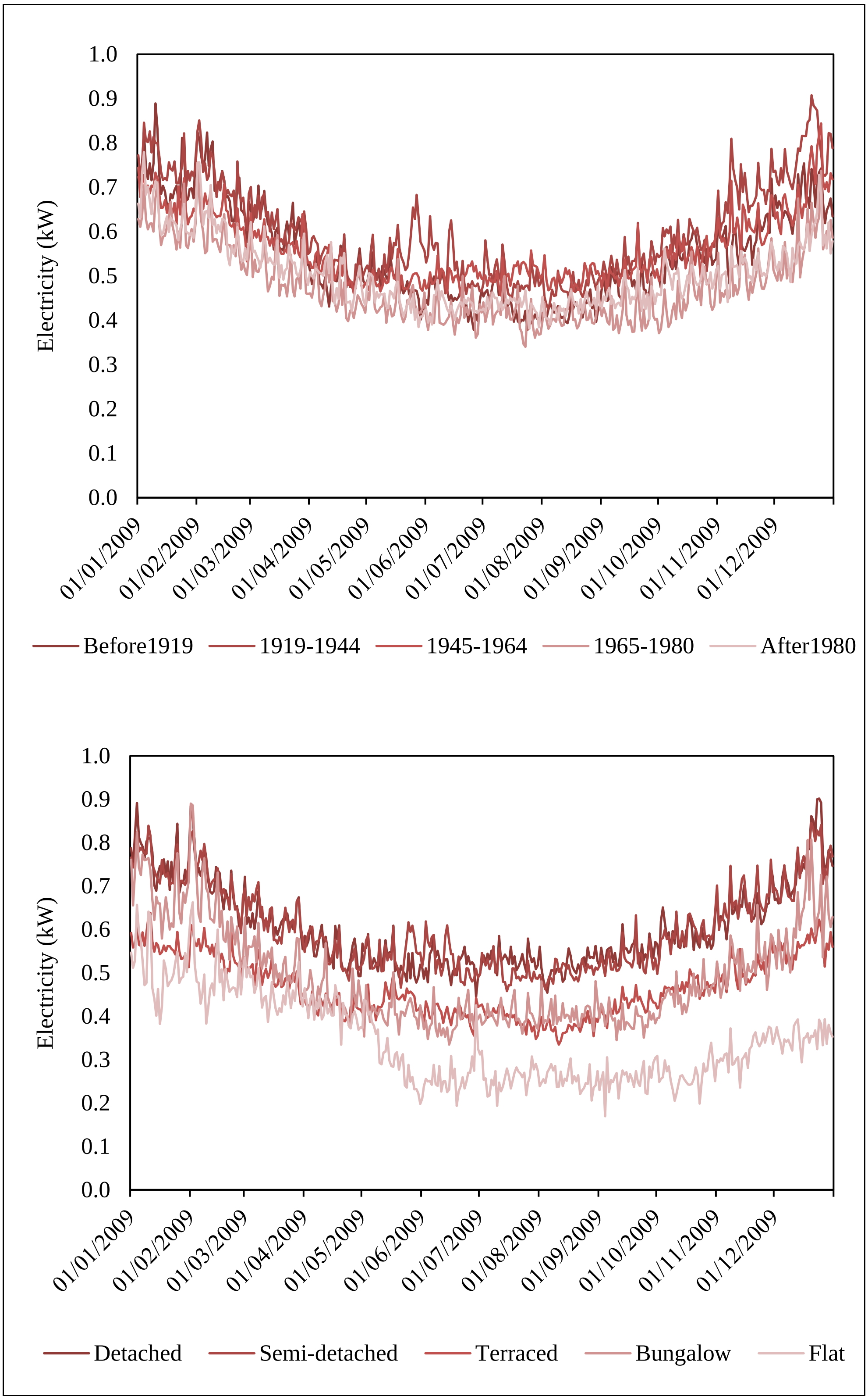

Figure 3.12: Daily electricity load profiles of various dwellings ages and types.

3.4.3 Hourly load profiles

Figure 3.13 demonstrates the average hourly electricity and gas consumption profiles per dwelling versus the average external air temperature for the year 2009. It shows that the monitored gas and electricity consumption was clearly linked to changes in the external temperature, and the volatile seasonal change in domestic gas consumption, with most of the consumption occurring between November and May.

At the aggregated scale, with the data averaged across the sampled dwellings, the maximum hourly gas consumption surpassed 9.2 kW per dwelling during the coldest periods of the year, which is about seven times higher than the winter peak hourly electricity demand (over 1.3 kW). In contrast to the high winter energy consumption due to the high heat demand, the maximum hourly gas consumption was less than 1.5 kW per dwelling in the summer, and this dropped below 0.2 kW per dwelling during summer nights – lower than the electricity consumption for the same period.

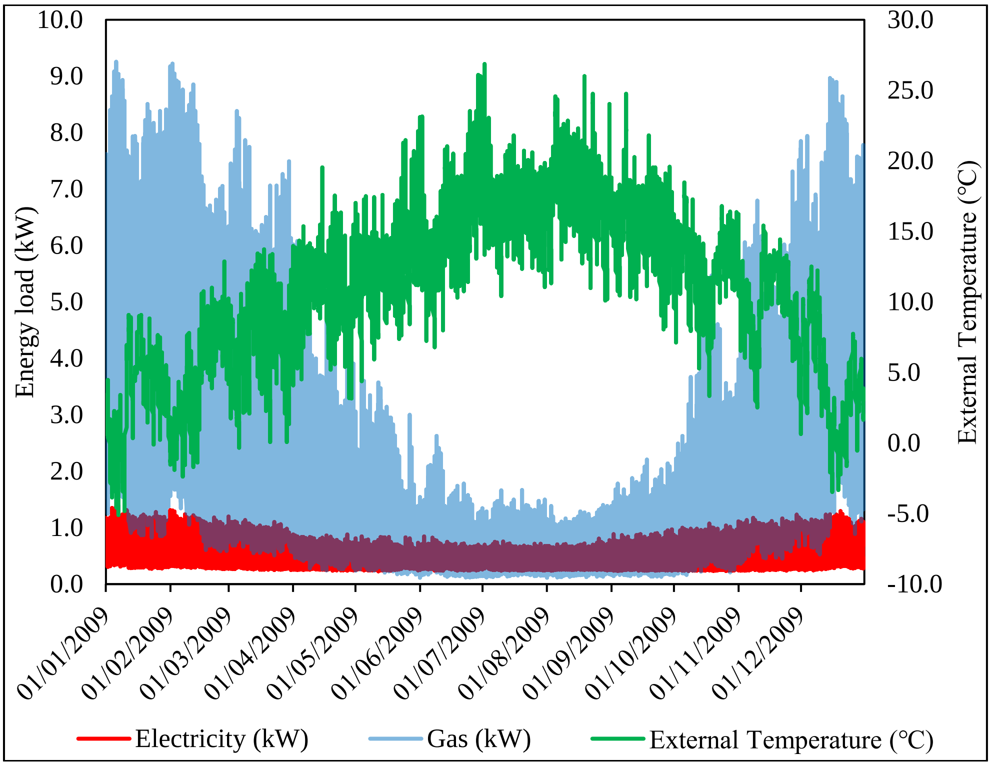

Figure 3.13: Hourly electricity and gas load profiles versus external temperature in 2009.

The diagram also reveals that the average hourly electricity consumption per dwelling throughout 2009 was steadier than the average hourly gas consumption per dwelling. The evening peaks of hourly electricity loads fluctuated from more than 1.3 kW per dwelling in the winter to below 0.7 kW in the summer. Unlike gas consumption peaks during the winter months, which were mostly triggered by demand for space heating, the electricity consumption peaks in the winter were most likely caused by additional lighting and the use of home appliances.

3.4.4 Hourly load duration curves

Because energy consumption fluctuates according to seasonal changes in weather conditions, load duration curves that cover an entire year are commonly applied in industries for the purposes of energy generation capacity sizing and cost optimising for multi-source energy co-generations such as combined heat and power (CHP) plants. The electricity and gas load duration curves for 2009 were constructed on an hourly basis for 8,760 hours from the highest hourly energy consumption to the lowest, as shown in Figure 3.14.

Both the electricity and gas load duration curves dropped from their maxima to under 60% of their peak demands after around 1,000 hours. The aggregated gas load duration curve declined continuously over the year, and fell below 50% (4.6 kW) of its winter peak after about 1,400 hours, then reached a bottom of 1% (0.1 kW). The electricity load duration curve was below 50% (0.7 kW) of its winter peak after about 2,100 hours, and terminated at 17% (0.2 kW). Moreover, the load factors for electricity and gas demands were 0.40 and 0.23, respectively, across all sampled dwellings. This may imply that some electronic appliances were continuously operating, such as fridges and broadband routers.

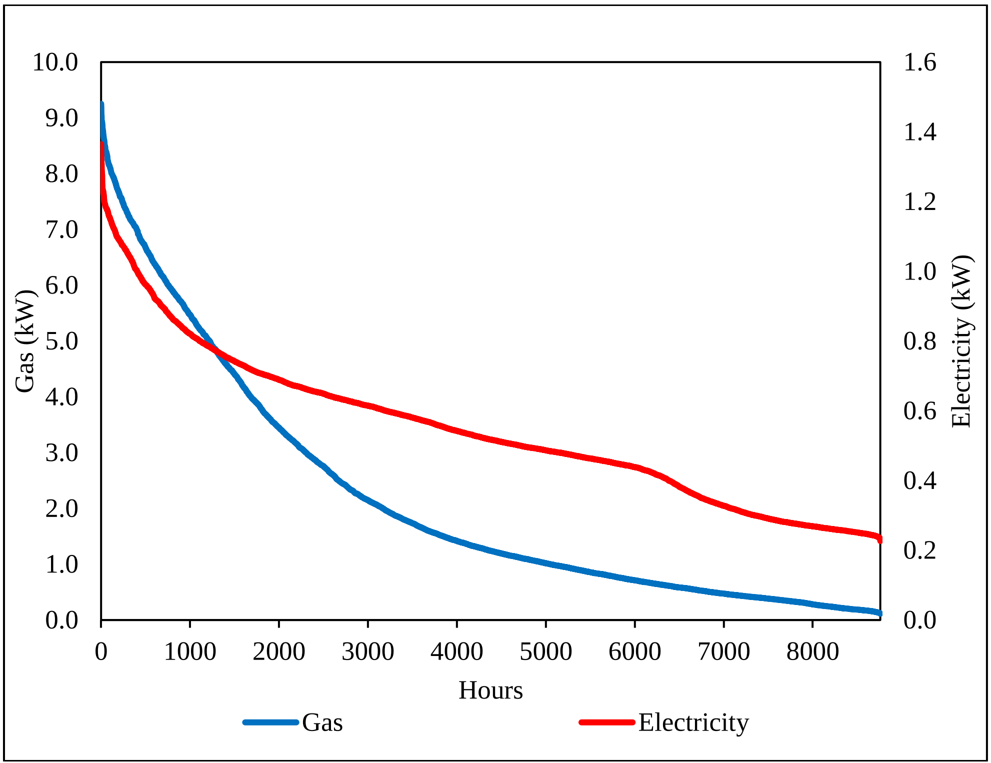

Figure 3.14: Hourly electricity and gas load duration curves over 8,760 hours.

3.4.5 Energy consumption and the external air temperature correlations

Energy consumption and external air temperature data from the sampled dwellings were averaged into daily values to examine the weather dependence of electricity and gas loads, as shown in Figure 3.15, employing the research method applied by Summerfield et al. (2015), which is a useful approach to calculating the linear response in energy demand, with respect to external temperature. The slopes in electricity and gas consumption relating to the changes in external temperature (commonly called power temperature gradients (PTG) or power signatures) were estimated through linear regression analysis, with an upper boundary temperature of 15 °C, accounting for approximately 320 W/°C for gas and 15 W/°C for electricity, respectively.

The diagram provides an empirical indication of domestic energy consumption per dwelling in response to external air temperatures, across all studied dwellings. At the aggregated level, it demonstrates the existence of linear interdependencies between energy consumption and external air temperatures (with the regression coefficient, R^2, larger than 0.9), up to around 15 °C. When external temperatures dropped, both electricity and gas demand increased almost linearly. Electricity and gas loads were noticeably higher when the external air temperature was lower, in the range from around -3 °C to 15 °C. The figure also shows that electricity consumption was less sensitive to external air temperature changes than gas consumption. Additionally, these results agree with the modelling study conducted by Summerfield et al. (2010), which identified the trajectory of total delivered energy (with an average heat loss coefficient estimated at 240 - 320 W/°C) for British dwellings.

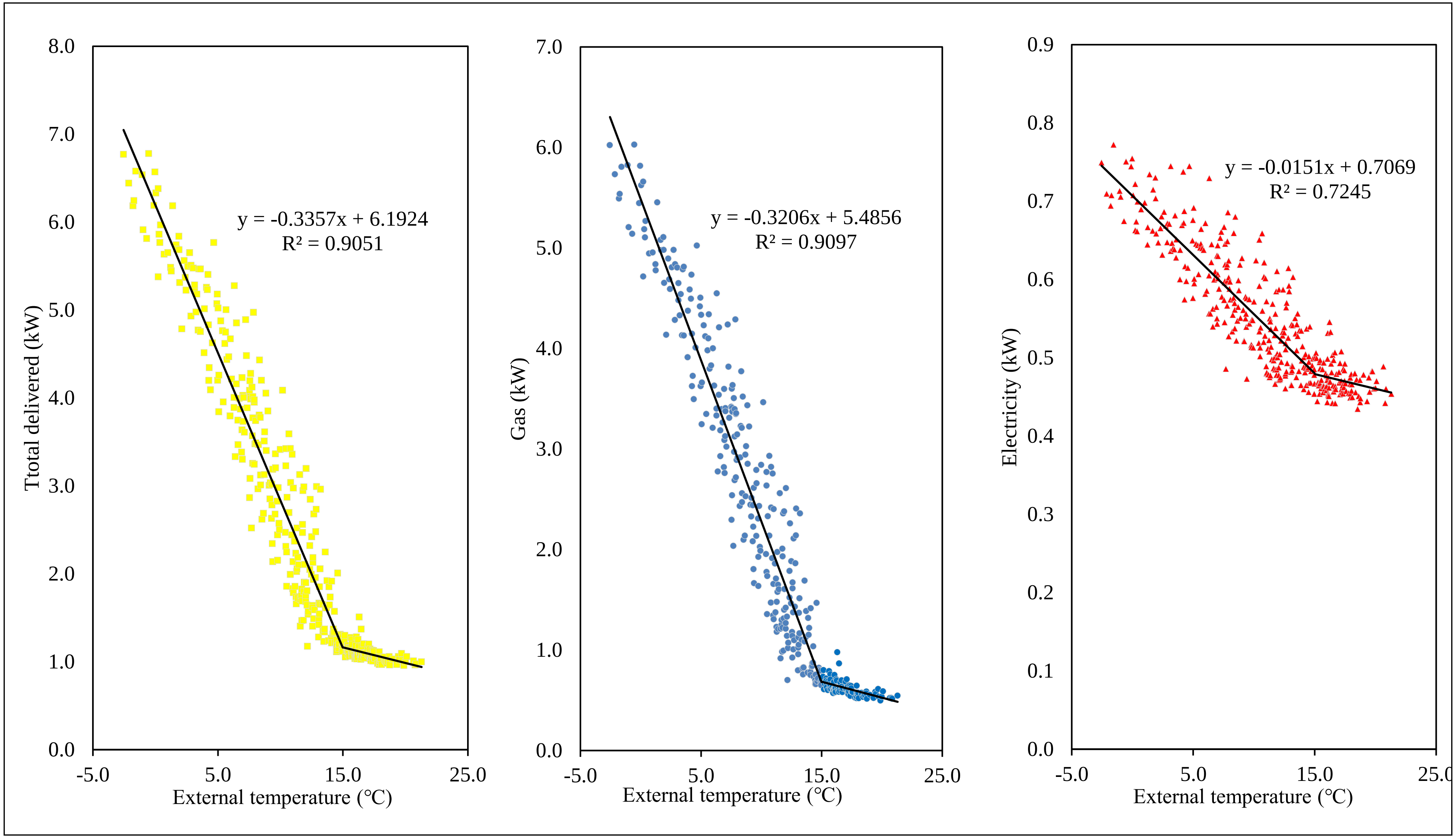

Figure 3.15: Daily delivered electricity and gas loads per dwelling in response to external air temperatures.

3.4.6 24-hour load profiles

By analysing smart meter data from the EDF subset of the EDRP dataset throughout the whole year of 2009, Figure 3.13 and Figure 3.15 previously illustrated that both electricity and gas consumption was higher when the external air temperature was lower. In this subsection, 24-hour gas and electricity load profiles are demonstrated over the seven days of the week, as well as on the hottest and coldest days (one weekday and one weekend) in 2009. Smart meter data were resampled from half-hourly raw data to hourly, and 24-hour load profiles were constructed between 0:00 and 23:00. According to the Met Office (2017), Monday 29th June and Sunday 23rd August were the two hottest days of 2009, and data from these two days were analysed to showcase load profiles when the space heating demand was deficient. The two coldest days of 2009 were identified as of Tuesday 6th January and Saturday 10th January, and smart meter data for these two days were used for the sampled dwellings to study the winter peak load profiles. The results are outlined in Figure 3.16 to Figure 3.21.

3.4.6.1 Week-long profiles

Figure 3.16 and Figure 3.17 show hourly gas and electricity load profiles for seven consecutive days, and the average 24-hour load profiles over the year 2009. According to the annual average load profiles, both electricity and gas consumption was low after midnight until around 5:00. It then increased sharply in the early morning, amounting to approximately 4.0 kW per dwelling for gas and 0.6 kW per dwelling for electricity. Unlike the gas load profiles, which have two pronounced peaks (around 6:00-7:00 and 17:00-18:00) and a shallower trough around noon, the electricity load profiles show a steady consumption until around noon, with one distinct peak at around 17:00-18:00 of roughly 0.9 kW per dwelling.

In terms of the load profiles across the seven days of the week, the gas and electricity load profiles almost overlapped from Monday to Friday, with morning peaks occurring at around 6:00-7:00, and evening peaks occurring at around 17:00-18:00. However, the morning gas peaks at weekends took place one hour later than on weekdays, while gas consumption around noon was relatively higher at weekends. Similarly, the morning peaks of electricity load profiles at weekends appeared at about 8:00-9:00, and consumption remained higher during later hours than on weekdays. This is primarily because people are more likely to be in their dwellings at weekends, which leads to higher energy consumption.

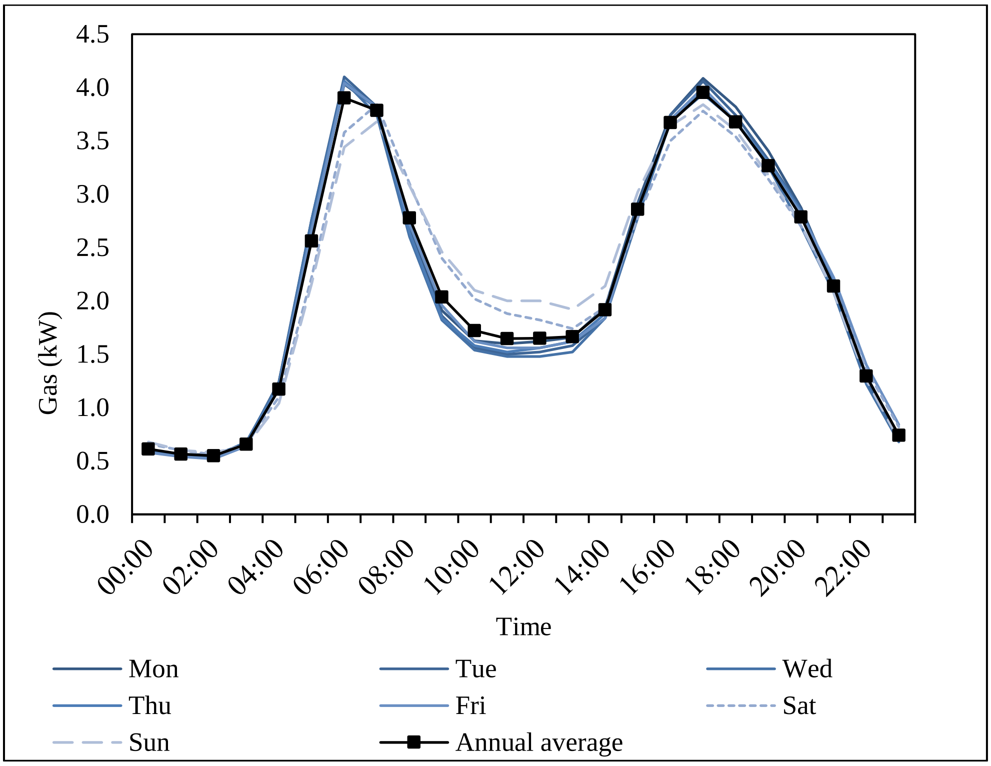

Figure 3.16: Average 24-hour gas load profiles over seven days, compared to the annual average.

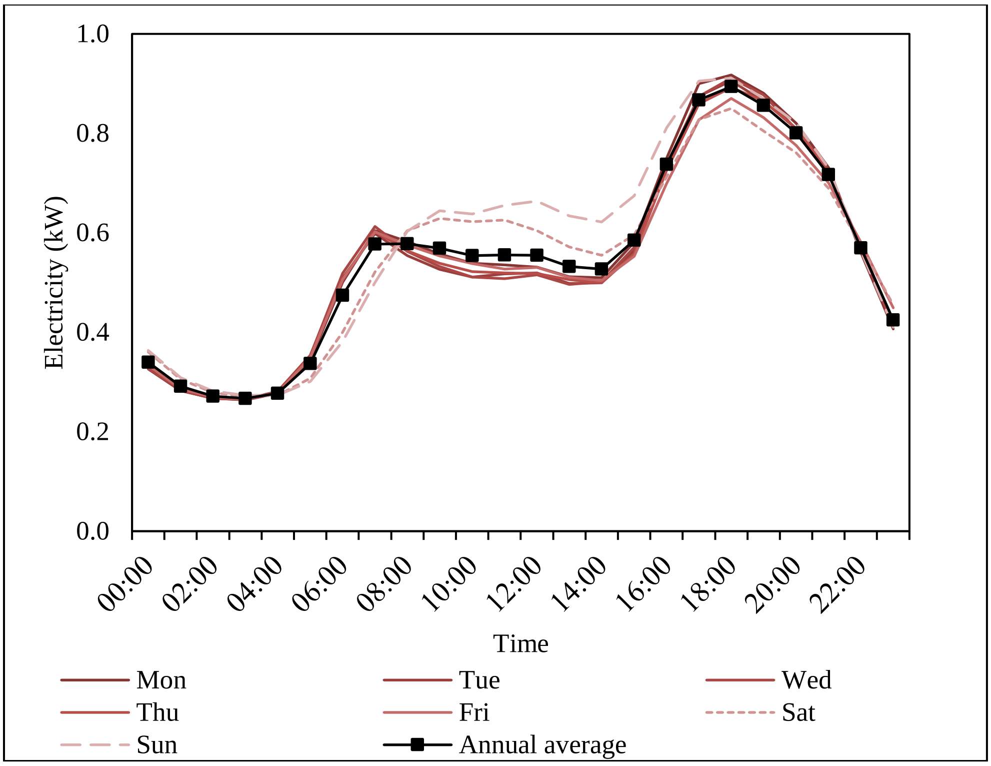

Figure 3.17: Average 24-hour electricity load profiles over seven days, compared to the annual average.

3.4.6.2 The two hottest days

Figure 3.18 and Figure 3.19 show gas and electricity load profiles for the two hottest days of 2009 (Monday 29th June and Sunday 23rd August), compared to the average 24-hour load profiles over the year. Gas consumption on the two hottest days was significantly lower than the annual average, and it is assumed that gas was primarily consumed for the purposes of domestic hot water and cooking on these two days. As outlined in Figure 3.18, the morning and evening peak gas loads were below 1.3 kW per dwelling, while the gas loads overnight were just about 0.2 kW per dwelling. Moreover, Figure 3.19 also reveals the electricity load profiles for the hottest days of 2009, indicating that the overall electricity loads were lower than the annual average in the daytime, while the evening electricity peak loads reached around 0.7 kW per dwelling – approximately 0.2 kW lower than the annual average evening electricity peak. Additionally, at night, the electricity loads on the two hottest days were similar to the annual average.

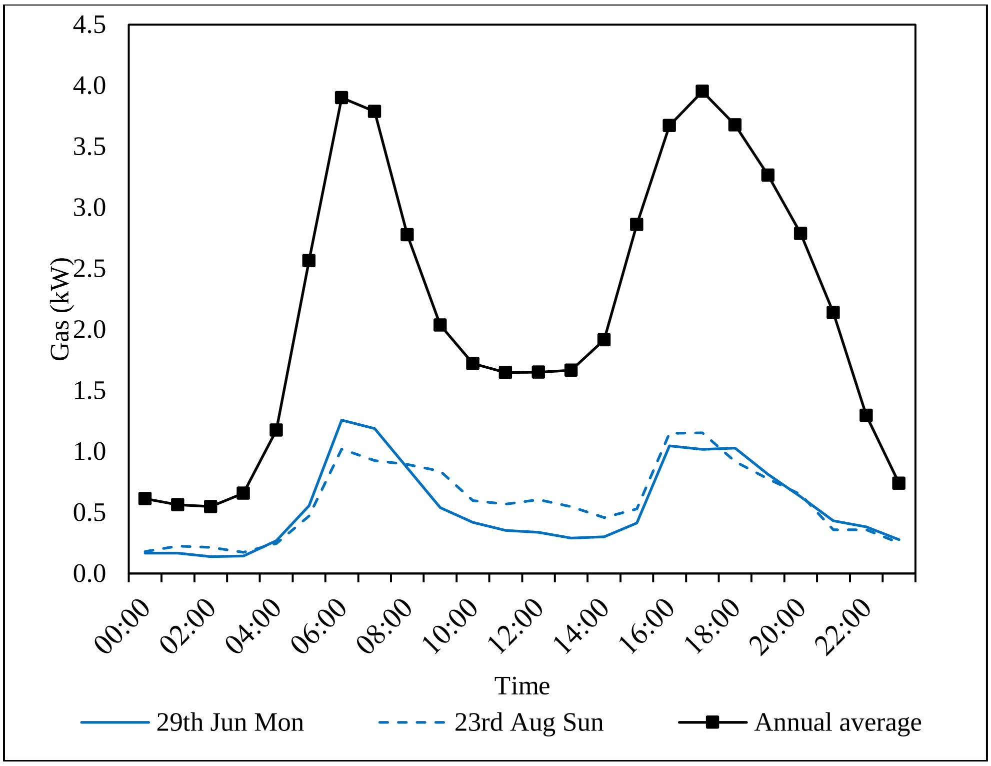

Figure 3.18: 24-hour gas load profiles of the two hottest days of 2009, compared to the annual average.

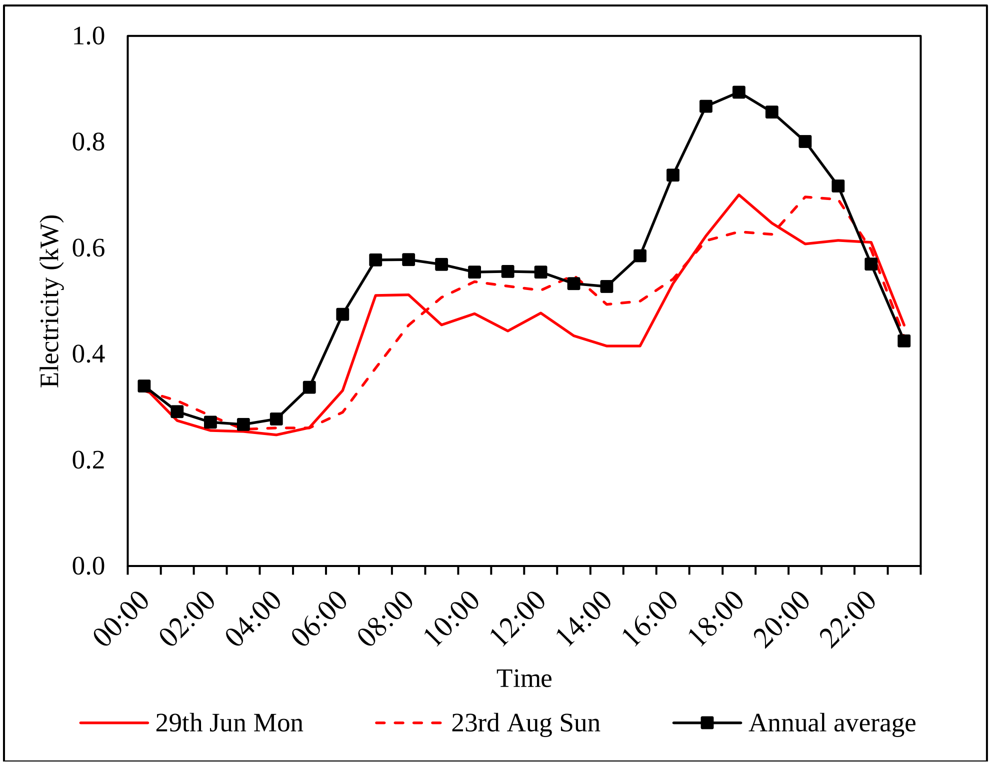

Figure 3.19: 24-hour electricity load profiles of the two hottest days of 2009, compared to the annual average.

3.4.6.3 The two coldest days

Figure 3.20 and Figure 3.21 illustrate energy consumption on the two coldest days of 2009 (Tuesday 6th January and Saturday 10th January) when the hourly average external temperatures dropped below -5 ℃ (Met Office, 2017). Both the electricity and gas peak loads occurred at around 17:00-18:00, but with much higher magnitudes, compared to the annual average 24-hour load profiles. On the coldest day of the year (Tuesday 6th January), peak gas and electricity consumption was over 9.2 kW and 1.3 kW per dwelling, due to the higher heat loss from buildings and increased usage of heating, lighting, and home appliances.

Figure 3.20 also shows that more gas consumption took place overnight on the two coldest days, compared to the annual average, while there was a slight increase in electricity consumption. Furthermore, the electricity and gas consumption at midday was higher at weekends than on weekdays, possibly because more dwellings tend to be occupied at those times, which leads to a higher demand for electricity and gas. Additionally, the gas-to-electricity evening peak ratios were 6.8 and 7.0, respectively, on the coldest weekdays and weekends, compared to the annual average of 4.4. In contrast, the morning peak ratios at 7:00 were much higher due to the relatively lower electricity demand in the morning, reaching to 11.2 (Tuesday), 14.7 (Saturday), and 6.6 (annual average).

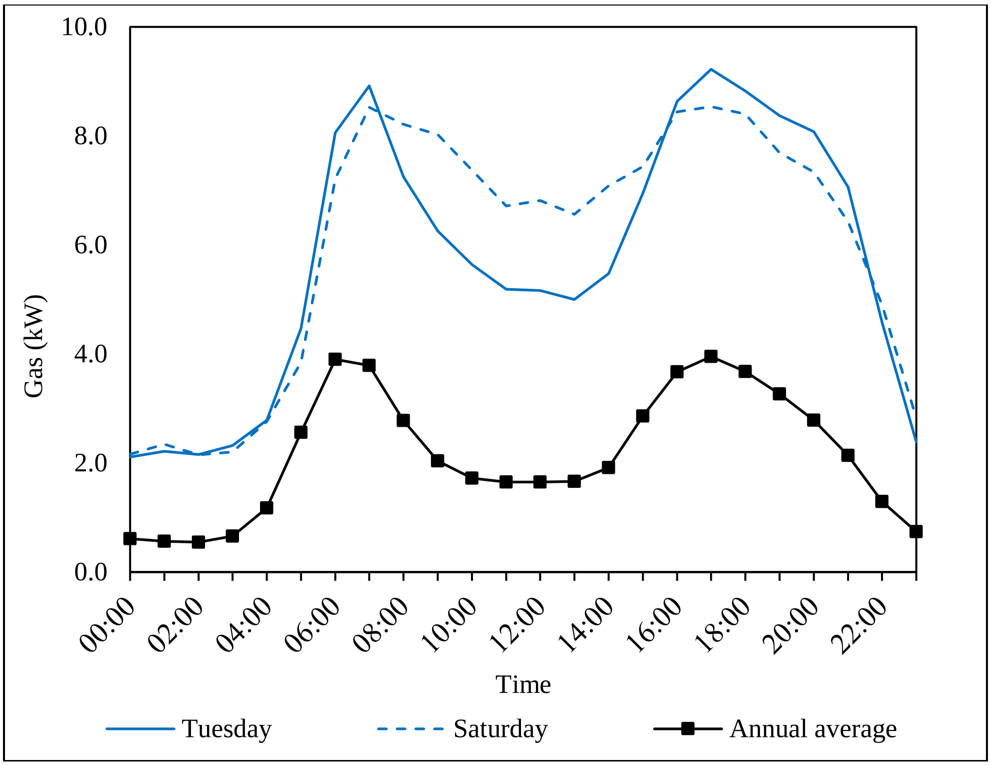

Figure 3.20: 24-hour gas load profiles of the two coldest days of 2009, compared to the annual average.

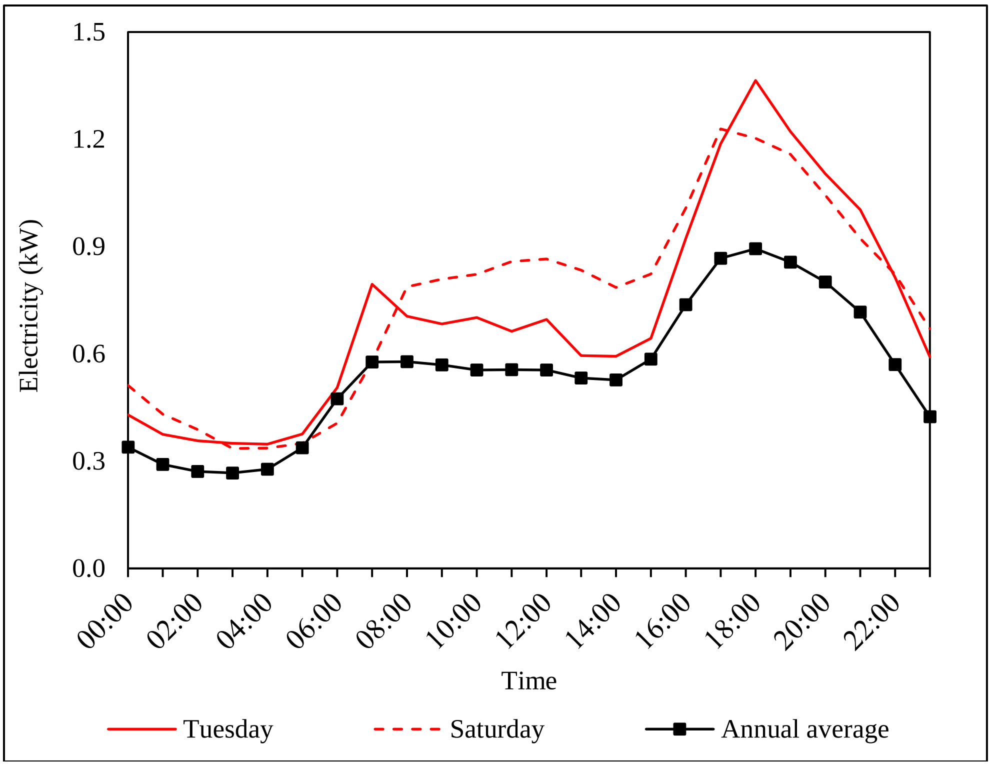

Figure 3.21: 24-hour electricity load profiles of the two coldest days of 2009, compared to the annual average.

3.4.7 Energy demand diversity of the two coldest days

As shown in the previous figures, domestic energy demand tends to be higher when the external temperature is lower. The aggregated peak gas and electricity loads for the coldest days may provide insight into the likely maximum loads a system (or a network) may experience, which may be affected by the size of the system and the energy demand diversity phenomena. The diversity effect and its impact on the aggregated peak loads was explored for the two coldest days of 2009, through the methods and equations discussed in Section 3.2.2 (page 79). The results are shown in Figure 3.22 and Figure 3.23 and summarised in Table 3.3.

In brief, the gas and electricity ADMD diagrams in Figures 3.22 and 3.23 illustrate the changes in peak hourly energy demand per dwelling due to the diversity effect, whereby the number of dwellings increased from one to 304 on the two coldest days of 2009. The figures indicate that the diversified gas and electricity peak loads per dwelling first decreased rapidly and then stabilised to approach to asymptotes when the number of aggregated dwellings increased, as expected. Furthermore, Figure 3.24 and Figure 3.25 reveal the estimated gas and electricity ADMD per dwelling with standard deviation from the mean value (using the same method applied by Barteczko-Hibbert (2015) and Love et al. (2017) for electricity ADMD), when the ADMD curves approach to asymptotes.

As shown in the figures and summarised in Table 3.3, the final gas and electricity ADMDs were lower on Saturday 10th January than on Tuesday 6th January. Due to the higher diversity factors, the final ADMDs dropped by about 33% for gas and 47% for electricity from their initial values on Saturday 10th January, whereas the final gas and electricity ADMDs decreased by less than 30% on Tuesday 6th January.

Table 3.3: A summary of ADMD and the diversity factors for gas and electricity on the two coldest days in 2009.

	Tuesday 6th January			**Saturday 10th January**		
	Average ADMD per dwelling for a single dwelling	Asymptotic ADMD per dwelling	Diversity factor	Average ADMD per dwelling for a single dwelling	Asymptotic ADMD per dwelling	Diversity factor
Gas	12.37 kW	9.20 kW	1.49	12.97 kW	8.65 kW	1.57
Electricity	1.89 kW	1.35 kW	1.48	2.3 kW	1.22 kW	1.65

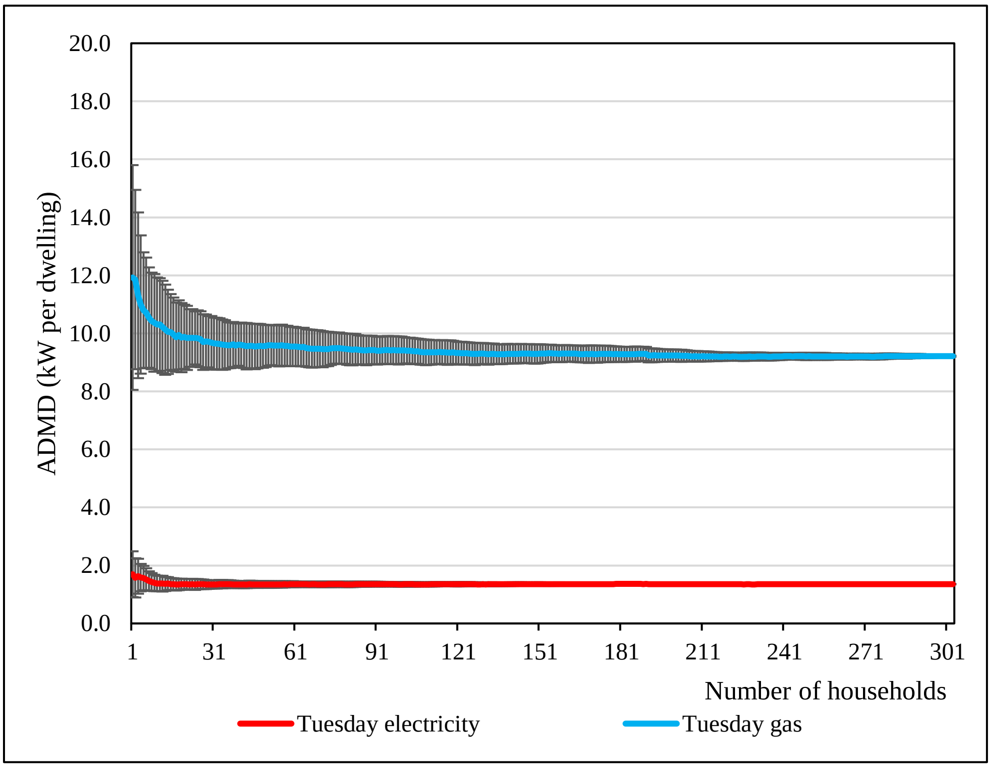

Figure 3.22: Gas and electricity ADMDs per dwelling on the coldest weekday of 2009.

Figure 3.22 shows that on the coldest weekday of 2009, the gas ADMD stood just below 12.4 kW (± 5.44 kW standard deviation from the mean) for the first dwelling, and then the value dropped rapidly to below 10.0 kW (± 1.2 kW) (80% of the initial gas ADMD) per dwelling by aggregating the load profiles of less than 20 dwellings. This number further decreased to 9.4 kW (± 0.48 kW) after 100 dwellings were aggregated, and reached its final value, to three significant figures, of 9.2 kW (± 0.24 kW), (74% of the initial gas ADMD) after 190 dwellings. In terms of electricity ADMD, the curves dropped sharply and became relatively flat, when only a few dwellings were aggregated together. The standard deviation error bars show that different samples of dwellings may provide different ADMD results, and the standard deviation from the mean of gas ADMD decreases from 5.44 kW per dwelling to 0.24 kW per dwelling from one to 190 dwellings, when the ADMD reached its final value to three significant figures.

As indicated in Figure 3.22, on the coldest weekday the electricity ADMD started from about 1.9 kW (± 1.26 kW standard deviation from the mean) at the first dwelling, and then quickly declined to 1.4 kW (± 0.28 kW) (74% of the initial electricity ADMD) per dwelling after only ten dwellings were aggregated. It only took approximately 20 aggregated dwellings for electricity ADMD per dwelling to reach to a final value of approximately 1.35 kW (± 0.17 kW) (71% of the initial electricity ADMD) per dwelling.

Likewise, as shown in Figure 3.23, the ADMD curves for the coldest weekend had similar shapes to those on the coldest weekday, but with higher starting and lower final values. However, more dwellings are needed to estimate the stabilised ADMD at the weekend than on weekdays, which implies that occupants may have more flexibility to consume energy at weekends. As the figure shows, the gas ADMD dropped rapidly from about 13.0 kW (± 6.38 kW standard deviation from the mean) at the first dwelling to below 10.0 kW (± 1.22 kW) (77% of the initial gas ADMD) per dwelling after aggregating the load profiles of 18 dwellings, and it remained below 9.0 kW (± 0.44 kW) (70%) after 80 aggregated dwellings. The gas ADMD reached its final value of below 8.7 kW (± 0.18 kW) (67% of the initial gas ADMD) per dwelling after 230 dwellings. Meanwhile, the electricity ADMD per dwelling dropped from around 2.3 kW (± 1.30 kW) to 1.3 kW (± 0.33 kW), when the number of aggregated dwellings increased from one to ten. The electricity ADMD per dwelling remained at 1.22 kW (± 0.15 kW) (53% of the initial value) with 38 aggregated dwellings.

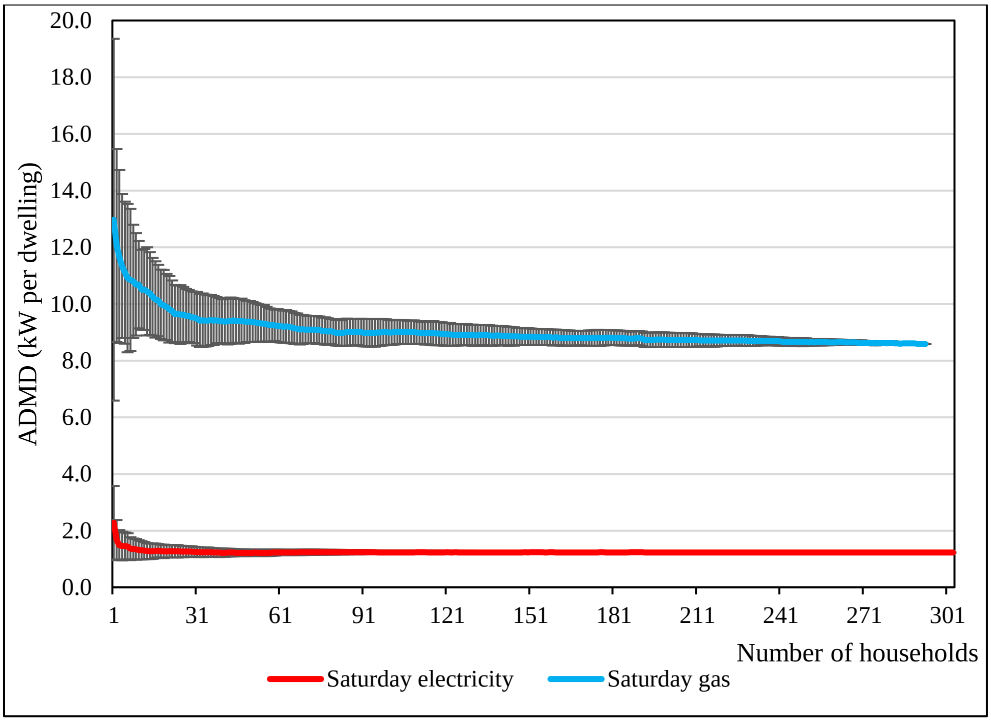

Figure 3.23: Gas and electricity ADMDs per dwelling on the two coldest weekend of 2009.

Figures 3.22 and 3.23 show that the after diversity maximum demand per dwelling drops meaningfully when less than 20 dwellings are added to the same system, and that the maximum demand per dwelling decreases towards an asymptote as more dwellings are added to the network, due to the diversity effect. Previous studies (Willis, 2004) suggest that an accurate electricity ADMD could be estimated within a group of 100 homogenous dwellings, while this study found that the electricity ADMD per dwelling remains the same to three significant figures after around 30 dwellings (during the coldest time of the year).

Nevertheless, this study also reveals that the strength of the diversity effect from gas consumption was lower than for electricity consumption within 100 dwellings, and that more than 100 dwellings are needed to estimate the final gas ADMD. Although the rate at which the ADMD per dwelling decreases becomes low after 100 dwellings, over 230 dwellings were required for gas ADMD to remain the same to three significant figures.

In addition, the graphs in Figure 3.24 and Figure 3.25 show the gas and electricity ADMDs per dwelling against 1/number of dwellings (excluding the first ten dwellings). Linear trendlines are applied in order to extrapolate the number of aggregated dwellings to infinity, based on the 304 sampled dwellings, in order to estimate the asymptotic ADMDs per dwelling. The results show that the final gas and electricity ADMDs on the coldest weekday were 9.20 kW and 1.35 kW per dwelling when the number of dwellings approached infinity, while the values dropped to 8.65 kW and 1.22 kW per dwelling on the coldest weekend due to higher diversity factors.

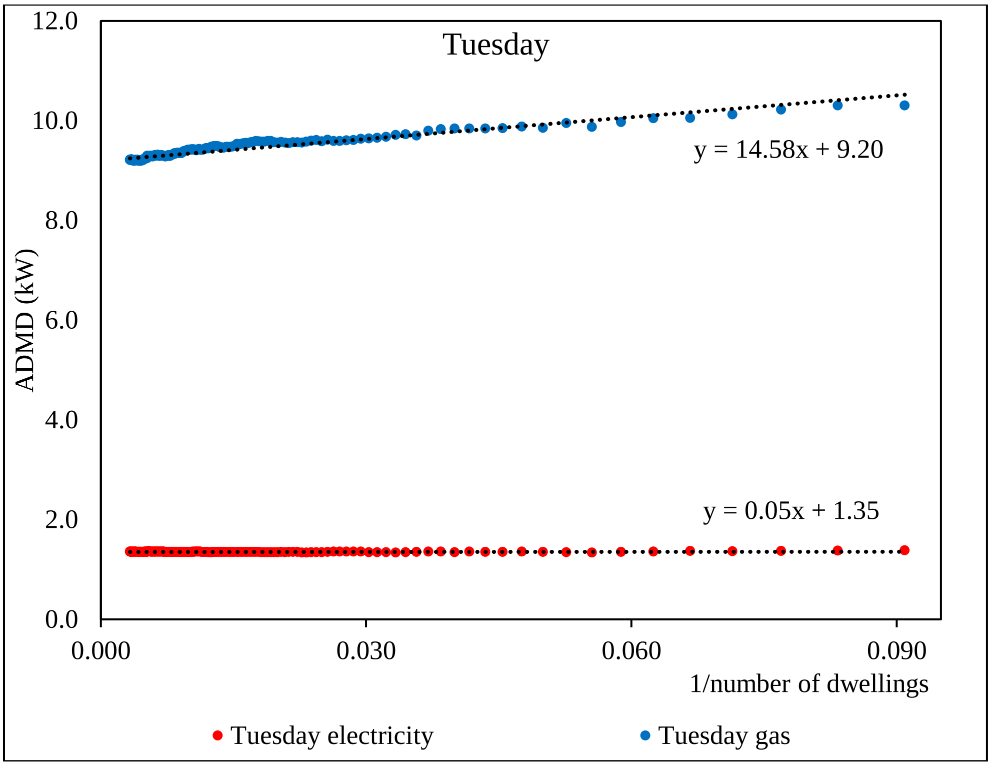

Figure 3.24: Gas and electricity asymptotic ADMDs per dwelling on Tuesday 6th January 2009 through extrapolation.

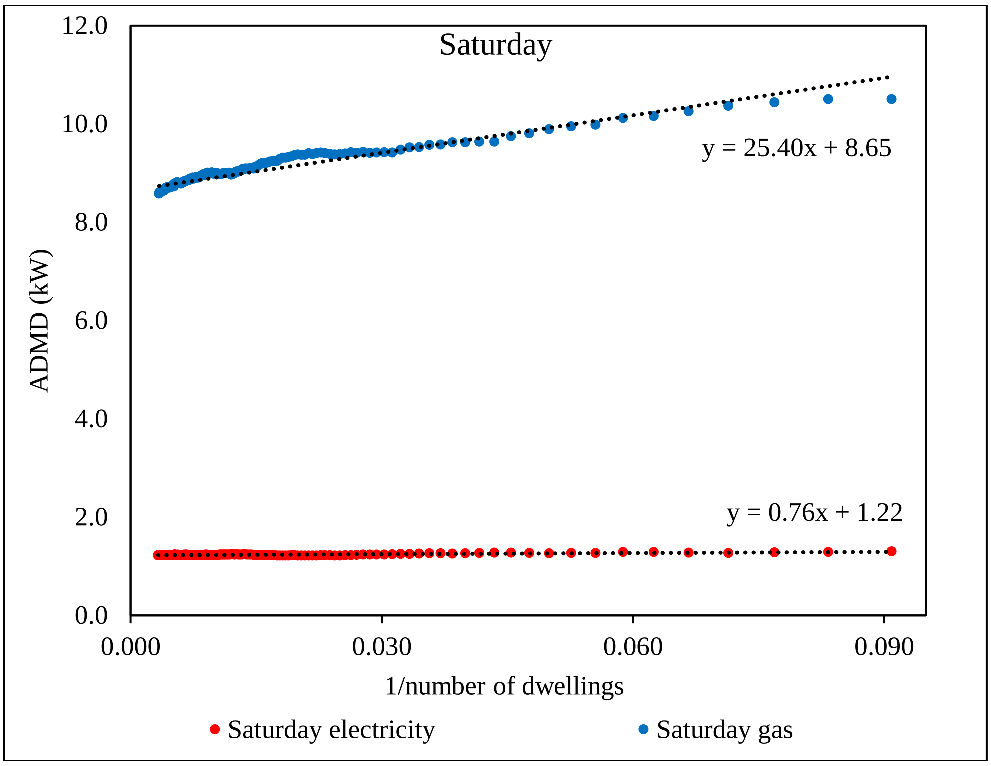

Figure 3.25: Gas and electricity asymptotic ADMDs per dwelling on Saturday 10th January 2009 through extrapolation.

3.4.7.1 External temperature and time of day when the ADMD occurred

Figure 3.26 and Figure 3.27 provide more details about ADMD, regarding the time and external temperature at which the aggregated peak demand can occur as a result of the diversity effect. Hourly gas and electricity consumption and external temperature data throughout 2009 were used to calculate gas and electricity ADMDs, as well as to identify the external temperature and time when the stabilised ADMDs occurred with 304 random trials, as the number of aggregated dwellings increased from one to 304.

As expected, Figure 3.26 indicates that at an aggregated level, both gas and electricity ADMDs tend to occur when the external temperature was negative. Figure 3.26 also validates that only about ten aggregated dwellings are needed to prove that the stabilised gas ADMD occurred on the coldest day, when the external temperatures fell below 0 °C. Nevertheless, it takes about 70 aggregated dwellings to expect that the stabilised electricity ADMD occurred when the external temperature fell below 0 °C.

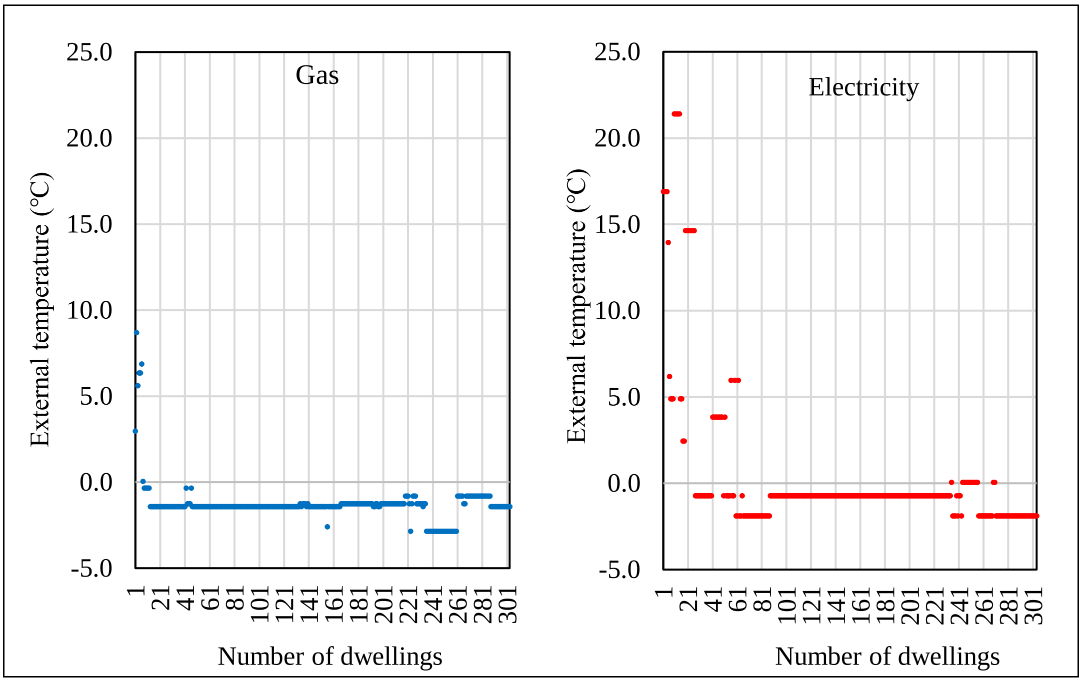

Figure 3.26: External temperatures when the gas and electricity ADMDs occurred.

Figure 3.27 answers the question regarding the time at which the gas and electricity ADMDs occurred over 24 hours, when the overall number of aggregated dwellings increased from one to 304. It reaffirms that the aggregated gas consumption peaked at either around 7:00 or 17:00, when the number of aggregated dwellings was more than 10, as previously revealed in Figure 3.20.

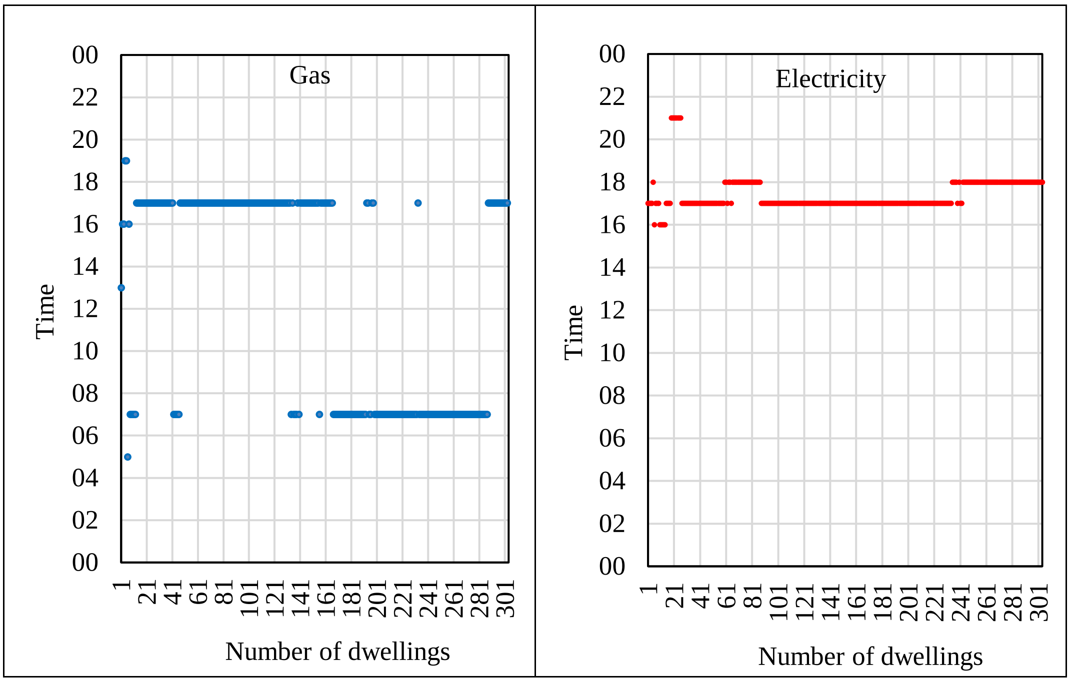

Figure 3.27: The time of day when the gas and electricity ADMDs occurred.

In contrast, electricity consumption had only one peak that occurred around 17:00 to 18:00 at the aggregated level, as in Figure 3.21. Moreover, Figure 3.27 also indicates that although the diversity effect could reduce the ADMD per dwelling on the aggregated level, when the total number of dwellings in a system (or a network) increases, it did not significantly affect the time when the aggregated gas and electricity peaks for a system occurred.

3.4.8 Gas boiler versus electric heat pump load profiles

This study analyses smart meter data from the EDRP field trials and electric heat pump data from the RHPP field trials, respectively. Because the individual dwellings involved in the EDRP and RHPP field trials have different starting and finishing times, this study averages the monitored data among all dwellings, based on the dates and months across the available datasets. Domestic heat pump electricity consumption data from Lowe et al. (2017) were averaged from two-minutely to hourly to construct the electricity load profiles for electric heat pumps over a year in order to compare the gas load profiles generated based on the EDRP smart meter field trials. Figure 3.28 shows the average hourly electricity consumption per heat pump over a year.

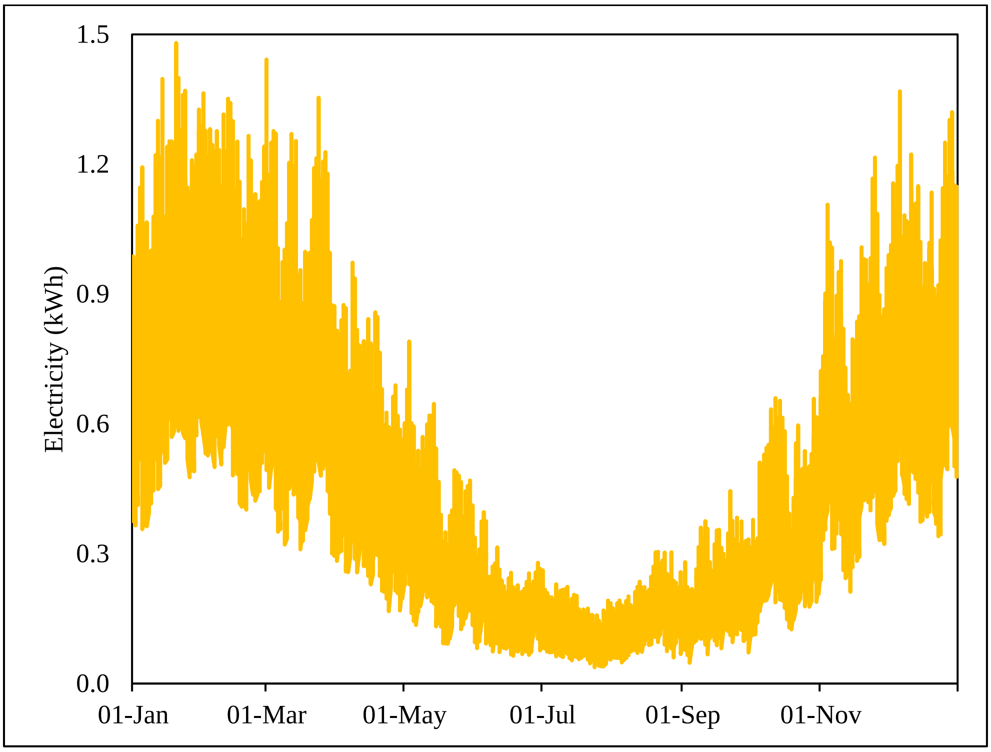

Figure 3.28: The hourly electricity load profile from electric heat pumps across a year.

As the figure displays, similarly to the seasonality features found in gas boiler load profiles (Figure 3.6), despite the variable weather conditions in different years, the electricity load profile from heat pumps reveals very strong seasonal changes, with the winter peak hourly electricity consumption reaching almost 1.5 kW per heat pump – more than five times higher than peak hourly electricity consumption in the summer (ranging from approximately 0.3 kW to 0.14 kW per heat pump during the period from June to September).

Gas loads from individual gas boilers and electricity loads from individual electric heat pumps were resampled into hourly and daily averages and normalised from 0 to 1 over a year (with peak load as 1). Figure 3.29 (daily) and Figure 3.30 (hourly) showcase a comparison between normalised load profiles over one year, looking at electricity loads from individual heat pumps (RHPP, 418 sites) and gas loads from individual gas boilers (EDRP, 8,466 sites). Although the normalised load profiles were similar on a daily basis and throughout the various seasons of one year, as shown in Figure 3.29, the hourly electricity load profile from heat pumps exhibited shallower troughs than the load profile of gas boilers. This indicates that at the aggregated scale with higher temporal resolutions, heat pumps operated differently to gas boilers.

Furthermore, the normalised (peak load as 1.0) load duration curves and 24-hour load profiles shown in Figure 3.31 and Figure 3.32 reveal that heat pumps might operate more continuously and longer than gas boilers at night. Figure 3.32 shows that the 24-hour electricity load profile from individual electric heat pumps was less peaky than the 24-hour gas load profile from individual boilers, while the electricity load profile from heat pumps shows that the morning peak is slightly higher than the evening peak, and the ratio of the electricity load at noon to the morning peak was about 0.65, whereas that of the gas load was around 0.45.

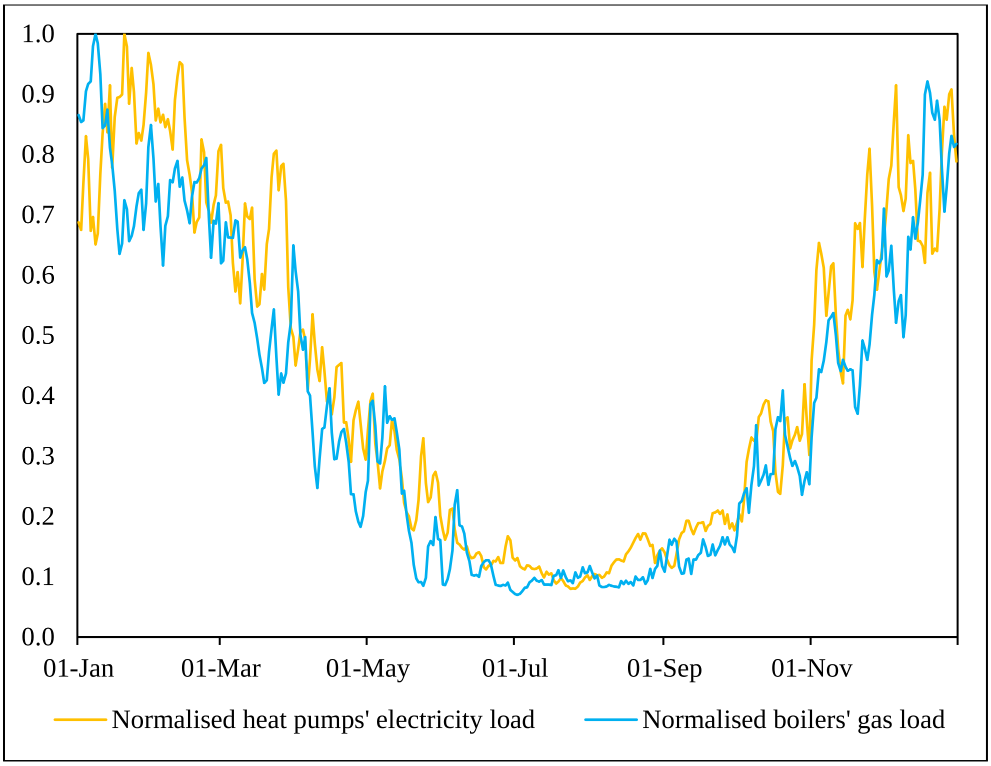

Figure 3.29: Normalised daily gas and electricity load profiles over one year.

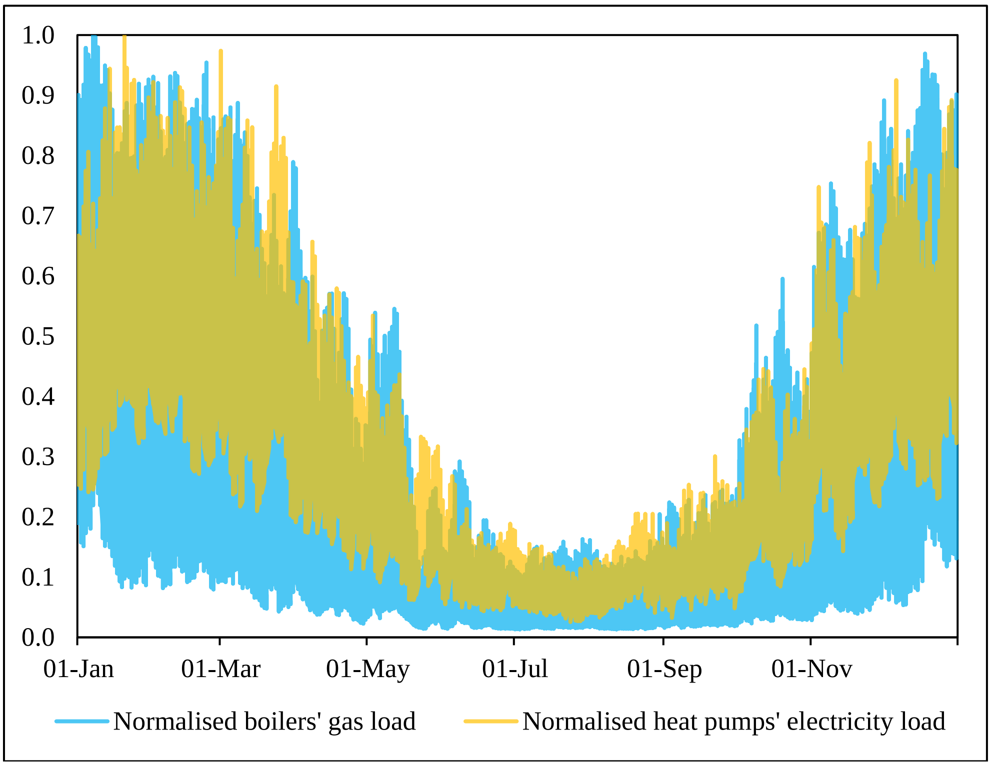

Figure 3.30: Normalised hourly gas and electricity load profiles over one year.

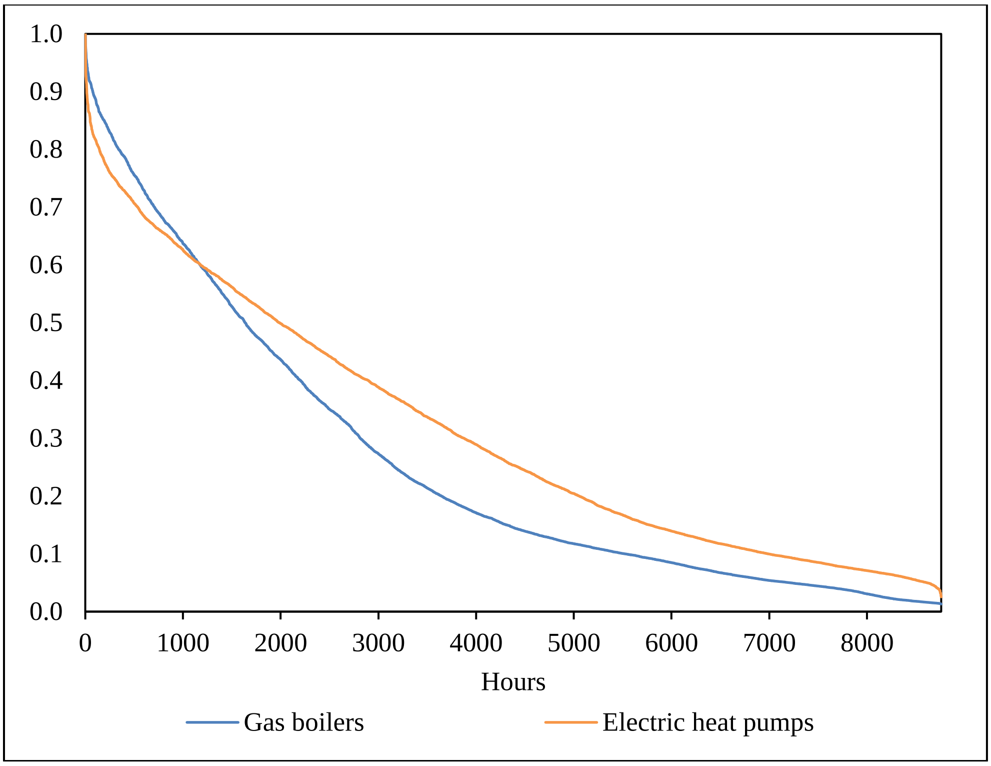

Figure 3.31: Normalised hourly gas and electricity load duration curves from gas boilers and heat pumps over a year.

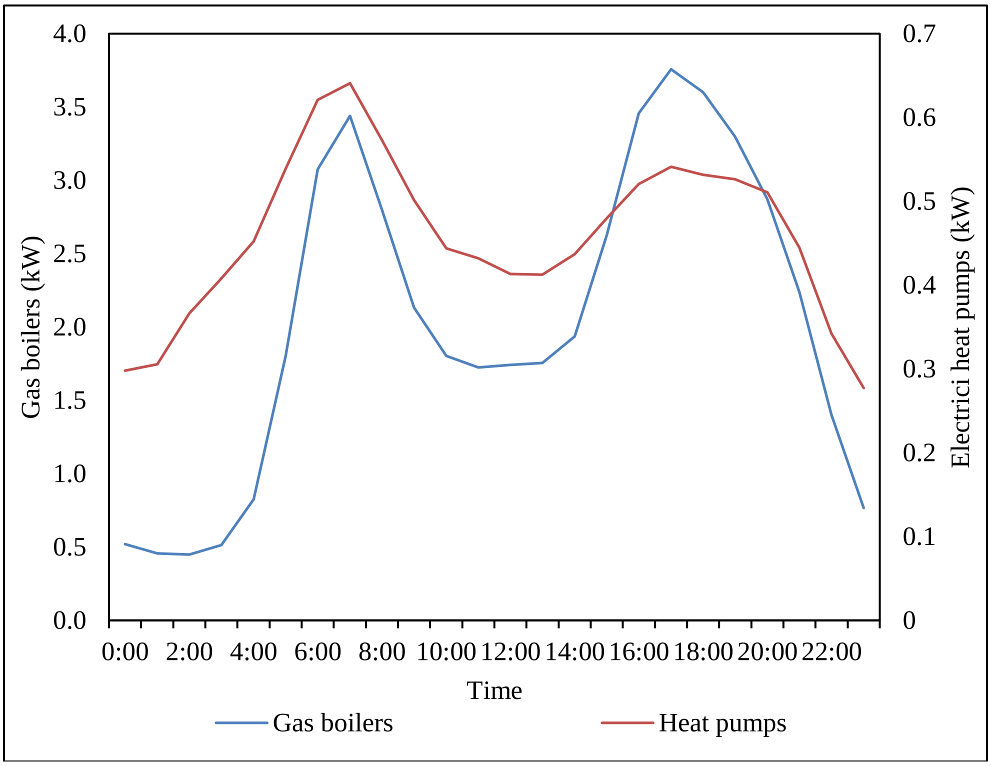

Figure 3.32: A comparison of 24-hour gas and electricity load profiles between gas boilers from the EDRP and electric heat pumps from the RHPP.

3.4.9 Implications of empirical energy load profiles and energy demand diversity studies for designing and sizing energy infrastructures

Energy consumption correspondingly changes according to the external temperature, as Figure 3.13 and Figure 3.15 illustrate, and the results from this study agree with previous research and statistics in terms of power temperature gradients and annual energy consumption in British dwellings (Druckman and Jackson, 2008; Summerfield et al., 2015; BEIS, 2018c). However, there are other variables that can influence peak energy consumption, such as heterogeneities in occupants and home appliances, and it is challenging to predict future peak energy demand. Studying energy consumption based on empirical data during cold weather conditions can offer support for the development of energy infrastructures that ensure energy security in the case of extreme weather events.

The diversity curve from the Danish standard DS439 has been widely used to size the domestic hot water supply for different numbers of dwellings for the UK's district heating networks (CIBSE and ADE, 2015). In general, the demand for the space heating of a dwelling spans over hours, whereas the demand for domestic hot water spans over minutes. However, the DS439 (Dansk Standard, 2009) calculated domestic hot water heating rates only, based on assumed usage patterns for a normative household, and admits that measured energy consumption can help to enable effective and energy-efficient operations. This being so, the DS439 may not be suitable for developing district heating networks that supply space heating only (CIBSE, 2020). Furthermore, there is no universal standard based on empirical diversity studies in the UK. Therefore, engineering design becomes defensive to ensure the reliability and continuity of service, and common practices tend to oversize the heating system (Tunzi et al., 2018).

The consequences of oversizing depend on the technologies involved. Where heating is provided by electricity, resistive losses vary inversely with the capacity of the distribution system, while oversizing may reduce distribution losses. Where heating is provided by natural gas, distribution losses are very low, and the oversizing of the gas distribution system is likely to have a minimal effect. In the case of heat networks, heat losses from distribution are roughly proportional to the capacity of the heat distribution system, and the impacts of oversizing may be significant because larger pipes are more expensive and have relatively higher heat loss.

This study explored the diversified maximum hourly energy demand in 2009, which was one of the coldest years in Britain recently. The findings could be advantageous for optimising long-term energy generation, managing short-term peak supply and demand, and designing and implementing energy facilities such as district heating networks. For example, although service pipes (tertiary pipes) must be designed based on non-diverse individual maximum heat loads for individual dwellings, distribution and transmission pipes (primary and secondary pipes) could benefit from the diversity effect to forecast maximum heat loads based on ADMD under cold weather conditions and mitigate the risk of oversizing substations and transport pipes. Because ADMD per dwelling decreases when the size of the heat network increases, economies of scale occur that reduce peak generation and transmission capacities, and therefore lead to reductions in costs.

The UK's industrial strategy involves a plan to phase out fossil fuel heating and invest in low-carbon heating technologies and expanded heat networks (BEIS, 2017). Although heat pumps and gas boilers might be used differently, the future electrification of the heating sector and the deployment of electric heat pumps would lead to amplified peak electricity loads (Love et al., 2017), which could transform both gas and electricity load profiles at all levels of aggregation. This study shows that domestic gas consumption is much higher than domestic electricity consumption in terms of both annual demand and hourly peaks, and if heat demand were switched from gas to electricity alone, the peak electricity loads would be greatly increased (Lowe and Oreszczyn, 2008; Sansom, 2015). Moreover, the expected future growth of electric vehicles could further affect domestic electricity load profiles, with a consequent need for planning and capacity upgrading, together with demand management and storage to cope with peaks in demand.

This study utilises domestic gas consumption as a proxy for representing heat demand due to the absence of access to heat data for large numbers of dwellings. It does not distinguish between the demands for space heating and domestic hot water, while neither does this study examine heat storage, due to the lack of metadata. There is limited empirical data from district heating networks because most dwellings in the UK utilise individual gas boilers for space heating and domestic hot water, and the UK has one of the lowest district heating market shares in Europe (Hannon, 2015).

Previous large scale field trials and modelling research have revealed that both gas boiler and heat pump load profiles are characterised by a morning and evening peak, but the profiles differ in detail. Furthermore, different types of heat pumps could result in different ADMDs (Navarro-Espinosa and Mancarella, 2014; Element Energy, 2017; Love et al., 2017). Future studies could gather metered data from operating heat networks with high temporal resolutions to test the differences between aggregated gas boiler load profiles and district heating load profiles, and the impact of utilising heat stores on load profiles.

The analysis of energy demand and demand diversity offers insight that can improve energy networks operations to appropriately size energy generation and distribution infrastructures and capacities, and reduce costs through economies of scale. The results from this chapter provide an empirical basis to build a techno-economic model for heat pumps and district heating networks and thereby address the second subsidiary research question proposed by this thesis, and evaluate the economic and environmental trade-offs by utilising heat pumps and district heating networks according to various topological configurations.

Chapter 4: Techno-economic analysis of topological configurations to utilise heat pumps and district heating networks

Based on the results of heat demand analyses in Chapter 3, this chapter addresses the second subsidiary research question of this thesis:

What topological configurations of heat pumps and district heating could be implemented for the UK's dwellings, and what are the economic and environmental advantages or disadvantages of deploying heat pumps in different topological configurations?

Some figures and discussions in this chapter have appeared previously in the following conference/publication:

Wang, Z. 2017. Trade-offs in Levelised Cost of Heat among different domestic heating technologies. *All Energy Conference.* Glasgow, United Kingdom.

Wang, Z. 2017. Heat pumps in the UK's district heating: individual, district level, both or neither? *The 3rd International Conference on Smart Energy Systems and 4th Generation District Heating.* Copenhagen, Denmark.

Wang, Z. 2018. Heat pumps with district heating for the UK's domestic heating: individual versus district level. *Energy Procedia,* 149**,** 354-362.

Summary of Chapter 4

Electric heat pumps and district heating, together with decarbonised electricity, have been proposed as efficient and environmentally sustainable approaches to meet the UK's future domestic heat demand. Heat pumps are versatile and can be used as a standalone heating technology for individual dwellings. Also, they can be integrated into district heating networks to utilise different heat sources. However, the application of heat pumps in conjunction with district heating networks is limited in the UK, and they are considered new and risky technologies.

Based on the empirical analysis of heat demand from different types of dwellings and the quantification of demand diversity at an aggregated level, this chapter focuses on ways to meet domestic heat demand by utilising electric heat pumps and district heating networks through different approaches to connecting dwellings, heat pumps and district heating networks. This chapter describes a techno-economic assessment model and its input data in order to evaluate the economic and environmental advantages and disadvantages of utilising heat pumps in four proposed topological configurations when compared to a reference case where gas boilers are being used to meet residential heat demand.

This chapter appraises the technical, economic and environmental trade-offs of different ways of utilising heat pumps and district heating networks at five different scales. The model compares technology efficiencies, network heat loss and associated carbon emissions under different operational conditions. It quantifies the trade-offs between heat pumps' COP and operational temperatures, as well as heat loss and pumping energy for different district heating pipes. The results demonstrate the economies of scales of heat pumps and district heating networks by comparing heat pumps' capital costs, four topological configurations' levelised cost of heat over the technologies' economic lifetimes and the initial investment costs to install different heating technologies.

Besides comparing costs and carbon emissions among different heating options, this chapter also discusses the impact of different electricity pricing schemes on the overall electricity costs and levelised costs. Furthermore, this chapter evaluates the different components that contribute to the overall costs of meeting the heat demand, discusses the uncertainties of key model assumptions and inputs, and conducts sensitivity analyses to assess the relative importance of model input parameters and their impact on the overall levelised cost results for the proposed topological configurations to utilise heat pumps in district heating networks.

4.1 Introduction

Heat is the largest component of domestic energy consumption in the UK, providing space heating and hot water, and the majority of the current domestic heat demand is still provided by the direct burning of fossil fuels (DECC, 2013b). Chapter 3.4 (page 99) demonstrates that the average annual domestic gas consumption was almost four times higher than the average annual electricity consumption, while the aggregated peak hourly gas consumption was nearly seven times higher than the electricity consumption during the cold spells. With ambitious greenhouse gas emission reduction targets (CCC, 2020), it is unlikely that the UK's current approach of providing domestic heating will be able to address future heat demand in an efficient and sustainable way. Low-carbon heat technologies, such as electric heat pumps with decarbonised electricity, are needed to replace the current prevalent gas-fired heating systems.

The UK's domestic heating systems have undergone fundamental changes in the past; they still need radical transformations to achieve current climate and energy goals. Numerous studies have investigated the low-carbon heat market in the UK and suggested future heating strategies, and there are many potentially cost-effective technologies available that could help to satisfy the domestic heat demand in a more environmentally sustainable way (Scamman et al., 2020). A frequently suggested approach is that the UK must decarbonise its electricity grid, electrify the heating sector with high-efficiency heat pumps, and develop district heating networks.

There are different ways to use heat pumps for domestic heating based on their sizes and how they are installed. They can be used as individual heating technologies to replace individual gas boilers. This approach can meet domestic heat demand and eliminate gas consumption for heating. Based on a number of factors such as heat pumps' operating temperatures, the carbon content of electricity, and heat sources, heat pumps may operate at different COPs and achieve different levels of carbon emission reduction. In district heating networks, large heat pumps can be installed at the network's upstream to supply heat for the district heating system. This approach enables heat pumps to utilise local heat sources and low-carbon electricity to supply heat to heat networks with high efficiencies and low-carbon emissions. Small heat pumps can also be installed at individual dwellings to upgrade heat from low temperature heat networks, which have lower distribution loss. There are technical, economic, and environmental trade-offs among different approaches to utilising heat pumps for domestic heating in the UK.

There has been a rapid expansion of district heating networks in the UK in recent years (ADE, 2017), of which many of the networks involve district heating connected to CHP plants (CIBSE, 2017). Although many modelling tools have been developed to explore district energy systems, together with the integration of renewables, storage, and heat pumps (Allegrini et al., 2015), the number of commercialised applications of heat pumps in district heating schemes is minimal. The UK's markets for heat pumps and district heating are currently immature, and the best economic, social and environmental balance between different heating options is unknown, which must be considered in the context of current and future technical, economic and political uncertainties (CCC, 2016).

The UK's natural gas network has been developing over the last half century, and natural gas is the principal energy carrier for heating (DECC, 2013b). Accordingly, the established supply chain of gas boilers and the relatively cheaper natural gas, compared to electricity, impose significant challenges for the decarbonisation of the domestic heating sector in the UK. Low-carbon heat technologies tend to have higher upfront costs than incumbent heating technologies, and their future deployment requires government support and public acceptance. Eyre and Baruah (2015) claimed that there are great uncertainties regarding the future of residential heating, and the UK will be locked into a gas-based heating system if there are no significant policy interventions.

This chapter explores the application of heat pumps and district heating for the UK's domestic buildings. It assesses the technical, economic and environmental trade-offs among the different topological configurations to install electric heat pumps, from individual to district levels. Previous studies are limited to focusing on either individual projects or the whole energy system without distinguishing how heat pumps are connected or operated between dwellings and networks. This chapter investigates heat pumps and district heating on five different scales according to the number of dwellings connected and the aggregated after diversity maximum demand. Techno-economic modelling assessments are conducted based on the results of empirical energy demand analysis (Chapter 3), technologies' operational parameters, and a variety of cost elements to address the question: what are the economic and environmental advantages or disadvantages of deploying heat pumps in different topological configurations?

4.1.1 Topological configurations to integrate heat pumps into district heating networks

This chapter uses the terms ‘topological configurations’ or ‘topologies’ to describe the spatial relationship and connectivity between dwellings, electric heat pumps and district heating networks. Heat pumps can be versatile. There are four topological configurations to utilise electric heat pumps and district heating based on the sizes of electric heat pumps; how heat pumps are installed and operated; and the relative locations that show how electric heat pumps are connected to dwellings and integrated into district heating networks. This study considers four topological configurations to utilise heat pumps with or without district heating networks and two sets of district heating operational temperatures (high and low) as illustrated in Figure 4.1, and their comparative economic and environmental advantages are assessed through techno-economic modelling.

Topology 1: Individual electric heat pumps that are used as standalone technologies at individual dwellings, replacing gas boilers without district heating networks to meet the domestic hot water and space heating demand. Air source heat pumps and ground source heat pumps are utilised in this topological configuration.

Topology 2: No heat-generating measures at individual dwellings that are connected to district heating networks, and large scale heat pumps are installed in the upstream of heat distribution networks, working as heat generators to meet heat demand from individual dwellings. This topological configuration operates with high temperature water as the heat carrier.

Topology 3: This topological configuration utilises small scale individual heat pumps at individual dwellings, which are connected by a low temperature district heating network. It utilises potential available free heat sources in the upstream of heat networks, such as waste heat from data centres or food processing facilities. Heat pumps are working as boosters to meet domestic heat demand by extracting heat from the low temperature district heating networks.

Topology 4: This topological configuration has a combination of topological configurations 2 and 3 without the free heat sources in the upstream of heat networks. Heat pumps are used in both district heating networks and individual dwellings: large scale heat pumps in the upstream of a low temperature district heating network as heat generators and small scale booster heat pumps at individual dwellings using the district heating network as a heat source to meet heat demand from individual dwellings.

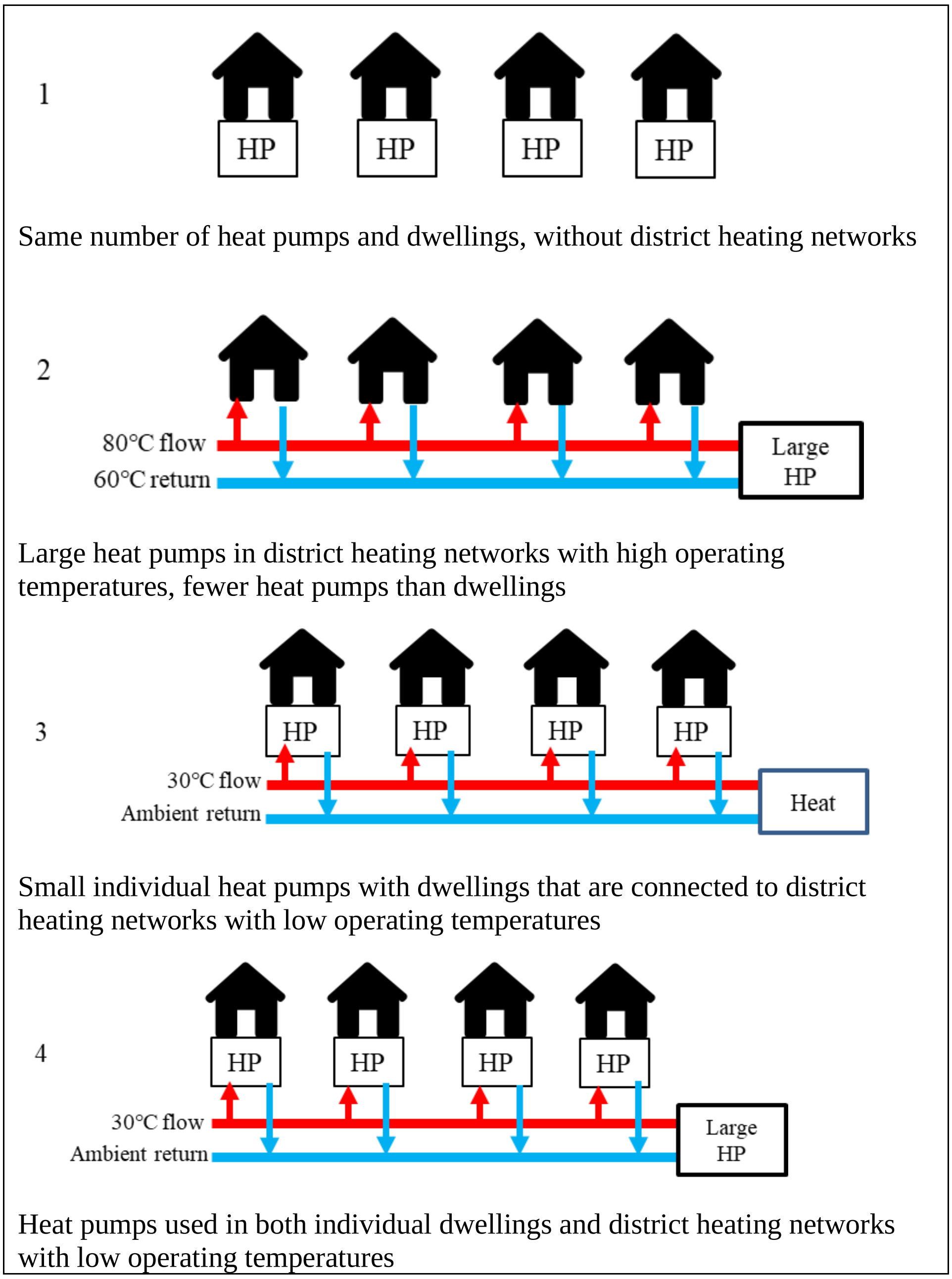

Figure 4.1: A simple abstracted illustration of four topological configurations to utilise heat pumps and district heating networks for dwellings.

4.1.2 Scales of district heating networks

There are diverse definitions regarding the size of a district heating network in different countries based on various factors such as the number of customers, heat demand densities, generation capacities, peak demand or annual consumption. There is no universal standard regarding the size of district heating networks in the UK. In previous studies, the scales of district heating networks were often vaguely defined or determined by the researchers' own experiences. This chapter proposes five scales of district heating networks adapted from two published studies conducted by the UK government (DECC, which has been incorporated into the Department for Business, Energy and Industrial Strategy [BEIS]) and the local government in London (Greater London Authority [GLA]).

The first study conducted by the UK government (DECC, 2013c) collected data from 1,765 existing district heating networks in the UK and concluded that heat networks in the UK are predominantly small. More than 70% (1,280) of the 1,765 studied networks were classified as small networks, with an average of 35 dwellings per network. Moreover, fuel types were recorded in 670 networks, and more than 90% of these networks only used natural gas to generate heat. This study defined three sizes (small, medium and large) of district heating networks based on the number of residential and non-domestic properties:

1. Small networks: less than 100 residential properties and less than three non-domestic users;
2. Medium networks: between 100 and 500 residential properties and between three and ten non-domestic users;
3. Large networks: 500 or more residential properties and more than ten non-domestic users.

Alternatively, the GLA (2014) published the district heating manual for London and defined decentralised energy with a range of technologies and scales from single building schemes to area-wide schemes connecting a large number of customers. This manual introduced three scales adapted from the Mayor's Climate Change Mitigation and Energy strategy (GLA, 2014):

1. Single development (small scale) that may include a single large building or a number of buildings with up to around 3,000 domestic customers;
2. Multi-development (medium scale) that could support up to 20,000 homes;
3. Area-wide development (large scale) that could supply 100,000 customers or more.

This chapter defines the scales of district heating networks based on the total number of dwellings in one single network adjusted from the two studies carried out in the UK by the DECC (2013c) and the GLA (2014), as shown in Table 4.1:

Table 4.1: The five scales of district heating networks and assumptions used in this study.

Scales	**Number of dwellings assumed for modelling**
1. Small heat networks (less than 100 residential properties)	100
2. Medium heat networks (between 100 and 500 residential properties)	500
3. Large heat networks (over 500 residential properties)	1,500
4. Single developments (up to 3,000 residential properties)	2,500
5. Medium multi-developments (up to 20,000 residential properties)	10,000

4.2 Literature review

This literature review section complements the literature reviewed in Chapter 2, focusing on a diverse range of research methods and tools that have been used to investigate the application of heat pumps and district heating networks for the residential heating sector. This section evaluates international studies and their results, limitations, and applicability to British dwellings, as well as discusses a range of research methods conducted for the UK's heating sector. It synthesises the similarities, differences and arguments of different modelling studies and their limitations to highlight the research gaps and opportunities in the field of electric heat pumps and district heating.

4.2.1 International studies

Different research methods have been used to investigate district heating networks in many European countries to assess heat demand and plan sustainable heat supply strategies. The Heat Roadmap Europe (HRE, 2017) applied a mapping tool, the Pan European Thermal Atlas (PETA), to study heat demand and supply densities and district heating and cooling strategies for a group of European countries and claimed that the combination of adopting energy efficiency measures, district heating in urban areas and heat pumps in rural areas is desirable to reduce energy demand, carbon emissions and fossil fuel imports. Moreover, the HRE explored district heating possibilities in five EU member states, including the UK, using an energy system model EnergyPLAN together with mapping the energy demand, distribution structures and energy assets. The results suggested that district heating could have the potential to supply over 70% of the heat demand in the UK by 2050 (Stratego, 2016). However, this study did not capture the heterogeneities in different types and ages of residential buildings, and it neither differentiated heating technology and district heating costs among different European countries nor considered different scales of district heating networks.

Besides heat demand densities, residential floor areas and the number of dwellings are also commonly used as a way to determine the size of residential district heating networks in European studies. Thyholt and Hestnes (2008) simulated heat demand and carbon emissions for residential buildings based on floor areas connected to district heating networks in Norway. The results indicated that new residential buildings with district heating had 50% lower total heat demand than dwellings built in accordance with the regulations from 1997, while the use of electricity for all heat purposes could result in an additional 1,000–1,200MW (5% of total electricity peak supply in 2008) peak power demand in 20 years. Nevertheless, this study did not discuss the impact of building regulations on the energy consumption of analysed dwellings. Moreover, Nuytten et al. (2013) modelled district heating operations using hourly electricity and gas consumption data from 100 individual dwellings in Belgium as a proxy and claimed that district heating networks offer more flexibility. However, neither of these two studies specified their definitions regarding the size of district heating networks.

Recently, several studies have been conducted in Europe to explore the application of large heat pumps in district heating schemes as well as their roles in energy systems. It is a widely held view that large scale heat pumps are critical to offering high efficiency and flexibility of an integrated smart energy system (Lund, 2015; Mathiesen et al., 2015; Connolly et al., 2016). Sayegh et al. (2018) reviewed existing district heating networks' status, recent technical feasibility assessments, case studies, and scenario studies in the EU. They pointed out that the existing networks are heavily dependent on fossil fuels; however, the network infrastructure can serve as a platform for integrated heat pumps and renewable energy to supply heat with zero or near zero emissions. They also argued that by incorporating heat pumps, district heating systems could be more cost-effective and ecologically justified. However, they did not specify the sizes and types of heat pumps they investigated, and there is no universal procedure to install, connect and operate heat pumps for all European countries as different technical characteristics and policy objectives need to be analysed for each individual case (Sayegh et al., 2018).

Furthermore, economic feasibility analyses conducted by Pensini et al. (2014) suggested that heat pumps based district heating is cheaper than resistance heating, and fossil fuels can be replaced by renewable electricity with heat pumps and only used as backups to achieve up to 97% of emission reduction from heating. Similar results were also found by modelling studies carried out by Dragićević and Bojić (2009) and Ommen et al. (2014). Scenario studies (Lauka et al., 2015) on the utilisation of heat pumps in district heating networks in the Baltic States suggested that it is feasible to utilise heat pumps in district heating to increase the consumption of renewable electricity as an approach to mitigate the non-regularity complications from fluctuating renewable electricity generation. However, none of these studies specified how heat pumps were installed or operated in their studies, and detailed data regarding the carbon content of electricity in different countries are needed to evaluate carbon emissions associated with heat pumps.

Denmark's heating system has transformed considerably from being oil-dominated in the 1970s to more than 60% of the total heating demand being met by district heating today, with heat from a diverse and evolving range of heat sources (DBDH and DEA, 2015). Many studies (Lund et al., 2010; Münster et al., 2012; Tol and Svendsen, 2012) conducted energy system modelling to investigate integrating district heating with renewable energy generation in Denmark. The common results suggested that improved building efficiency and gradual expansion of district heating with individual heat pumps were the most cost-effective solutions to meet the future heat demand in Denmark. Moreover, Lund et al. (2010) advised that in 25% of the Danish building stock, gas or oil boilers could be substituted by district heating and efficient individual heating measures.

A number of modelling case studies have been conducted to evaluate the network system efficiency and socio-economic impacts of integrating large scale heat pumps into the existing Danish district heating networks (Bach et al., 2016; Lund et al., 2016; Lund and Persson, 2016). Blarke (2012) conducted a techno-economic assessment of the Danish heating system and pointed out that well-designed heat pumps are more cost-effective than electric boilers. However, Bühler et al. (2015) argued that the economic operations of heat pumps on the large scales require a high level of utilisation of low temperature heat or renewable sources, in order to reduce its operating costs and compete with other types of heating systems.

Furthermore, Østergaard and Andersen (2016) modelled centralised large heat pumps and small booster heat pumps in Danish district heating by using energyPRO to simulate district heating temperature levels, heat loss, and heat pump performance. This study quantified that district heating with booster heat pumps for domestic hot water could reduce up to 39% of operational costs compared to district heating without booster heat pumps, mainly due to reduced heat loss and lower natural gas consumption. However, this study did not consider investment costs due to the lack of cost data for booster heat pumps.

Numerous case studies to investigate large heat pumps in district heating schemes have been carried out for Finland, Norway, and Sweden (Rinne and Syri, 2013; Ulbjerg, 2016; Averfalk et al., 2017; David et al., 2017; Nowak, 2017). Nevertheless, unlike some Scandinavian countries with well-developed district heating networks over the last few decades, the market share of district heating is very low in the UK (Hannon, 2015), and there are very limited commercial examples regarding the application of large heat pumps in the UK's district heating networks (Star Renewable Energy, 2017; EHPA, 2019a).

In addition, district heating may expand the network and increase production due to economies of scale when marginal average profits are greater than marginal average costs. The network could keep expanding until the production exceeds the optimal capacity, where the marginal average cost becomes larger than the marginal average profit to avoid diseconomies of scale. In order to develop district heating schemes, large investments in plants and pipelines are required in the early stage of construction, and this could lead to a natural or legal monopoly of district heating (Toke and Fragaki, 2008). Economies of scale have been studied in many industries that tend to have a monopolistic nature, for example, power generation (Christensen and Greene, 1976; Dornburg and Faaij, 2001), public transport (Lee and Steedman, 1970; Farsi et al., 2007), telecommunication (Gruber, 2001), and water utilities (Fraquelli et al., 2004; Bottasso and Conti, 2009).

Nevertheless, a limited number of academic studies have explored the economies of scale in district heating even though the technologies and costs have been changing over several generations. In Sweden, studies (Wibe, 2001; Söderholm and Wårell, 2011) have suggested that economies of scale were not prevalent in early Swedish district heating networks as district heating schemes were limited by fuel types and scales. Conversely, Park et al. (2016) used a variable cost function to evaluate district heating schemes in South Korea and suggested expanding district heating because the results showed that economies of scale were present and statistically significant, and economies of scale for South Korea Heating Corporation existed until the production volume surpassed 25 times the production volume in 2011. However, it is very challenging to measure economies of scale. Such studies usually require financial records, income statements, and cost reports, and no studies were found that have thoroughly investigated the economies of scale in the UK's district heating schemes.

4.2.2 Studies in the UK

Numerous studies have been carried out to compare alternative heating technologies through technical and economic valuations and market analyses in the UK (Rhodes, 2011; Element Energy, 2012; Chaudry et al., 2015). Market statistics revealed that unlike some European countries, the UK's current heat pump deployment rate is very low (IEA, 2017b), and heat pumps in the heating networks are new concepts for the UK's heating systems (Hawkey, 2012; DECC, 2016b). Sales records (Hannon, 2015) revealed that the UK had one of the lowest total installed heat pump capacities per capita among countries in Europe. Consequently, there are very few empirical studies regarding the operation of heat pumps in the UK's buildings and heat networks.

Nevertheless, many heat pump market analyses and modelling studies expected the future accelerated growth of domestic heat pump installations in the UK (EHPA, 2019a). Many of these market analyses were financially orientated with few details on the technical characteristics of heat pumps regarding their sizes and operations. Although the results were diverse according to various scenarios, it was commonly suggested that the deployment of individual heat pumps would grow dramatically over the next few decades, and electricity could become the principal supply of heat, with demand reduction (Delta-ee, 2014; National Grid, 2018).

Case studies and techno-economic studies regarding the applications of heat pumps in district heating networks have been conducted for a number of projects in the UK (Pöyry, 2009; Euroheat and Power, 2011; DECC, 2016a). A common finding is that heat pumps and district heating could substantially reduce carbon emissions but may also increase the cost of heat significantly. Moreover, many studies suggested that improving building efficiency is essential to ensure heat pump and district heating performance, and it should be considered before replacing the current heating systems (Connolly et al., 2014; ERP, 2017).

Researchers have conducted a diverse range of assessments to scrutinise individual heat pumps, including cost-benefit assessments (Self et al., 2013), cost and financial feasibility studies (Cockroft and Kelly, 2006; Kesicki, 2012), life cycle assessments (Shah et al., 2008), and environmental and social impact assessments (Fawcett, 2011; Delta-ee, 2014). Le et al. (2018) simulated the performance of air source heat pumps when retrofitted into dwellings and suggested that local climate conditions, dwellings characteristics, and operation control strategies could affect heat pumps' performance.

Moreover, a number of heat pump field trials were piloted to analyse the technical performance of heat pumps and residential heating patterns in the UK (EST, 2010; Kelly and Cockroft, 2011; Dunbabin and Wickins, 2012; Dunbabin et al., 2013; Gleeson and Lowe, 2013). Evidence suggested that carefully installed heat pumps can become a cost-effective way to meet the domestic heat demand while contributing to emission reduction targets in the UK. However, there is a lack of field trials in the UK to investigate different sizes of heat pumps in district heating networks.

Simulation modelling studies (Stratego, 2016) for the UK on the national level have suggested that district heating is more efficient and cost-effective in urban areas with high heat densities than the natural gas network, as it reduces fuel demand, carbon dioxide emissions and energy costs. Whereas, in off-gas grid rural areas, individual heat pumps may be the preferred heating option together with small shares of individual solar thermal and biomass boilers based on a balance across energy demand, emissions and costs. Furthermore, Li (2013) applied a spatially explicit model to explore the economic and technical potential of area-based deployment of district heating technologies for the UK. This study evaluated the costs of a range of individual and district heating technologies at different demand densities and suggested that electric heat pumps could be key enabling technologies for district heating to supply high proportions of heat demand through the phasing out of gas boilers.

Area-based heat maps have been created to estimate heat demand and evaluate heat supply technologies for the UK based on regional statistics. Similar to PETA, the National Heat Map was developed to support heating strategy designs in England using web-based maps and modelled heat demand data (BEIS and CSE, 2017). However, it was decommissioned and no longer working in 2018 (CSE, 2018). Likewise, Finney et al. (2012) applied geographic information system modelling to estimate heat demand and to produce heat maps for district heating in Sheffield, UK, to evaluate the economic and environmental impacts of district heating based on different heat sources and sinks. However, location-based heat maps do not capture energy demand heterogeneities in dwellings, and it is difficult to characterise area-based peak heat demand on adequate time resolution such as hourly peaks without an empirical basis. Further, there are additional features needed to be considered for district heating planning, such as building characteristics and occupants' acceptance.

Some studies investigated potential reasons for the slow development of district heating in the UK even though district heating with CHP was recognised as an economical method to supply heat in high heat demand areas over four decades ago (Marshall, 1977). Kelly and Pollitt (2010) conducted economic and policy research and noted that upfront infrastructure costs, the volatility of energy prices and uncertain energy policies are three critical barriers to adopting CHP-DH in the UK. Their findings are validated by Hawkey et al. (2013), who investigated the UK's political-economic context for district heating and cooling with case studies on CHP-DH networks in Aberdeen, Woking, and Birmingham. They emphasised the importance of combining social and financial capital to develop a long-term district heating infrastructure that has high upfront costs and long payback periods.

Several modelling studies examined the additional costs of integrating heat pumps into the UK's district heating networks and their potential to decarbonise the heating sector (Pöyry, 2009; Connolly et al., 2014; CCC, 2016). Government-commissioned scenario analyses for large heat pumps in the UK's district heating schemes have shown that there is the potential to reduce between 48% and 84% of carbon emissions; however, this may significantly increase the cost of heat (DECC, 2016b). In addition to modelling studies, case studies were developed to examine the deployment of heat pumps in district heating based on different operating methods and heating sources (DECC, 2016a). Nevertheless, none of these models distinguished the scales of heat pumps and district heating networks based on empirical evidence or specifically considered demand diversity for cost evaluations.

Furthermore, Delta-ee (2012) developed the UK's future residential heating scenarios to evaluate the optimal heating technology pathways based on detailed housing stock segmentations by modelling the building stock, technology performances, and customer choices. This study highlighted that the key challenge under any scenario to meet the emission reduction targets was to shift the majority of dwellings away from their gas-fired heating system to electric heat pumps or district heating. This study (Delta-ee, 2012) also admitted the fact that there are great uncertainties about heat pumps and district heating cost reductions, performance improvement, and their widespread 'retrofitability' in the UK.

Moreover, it is anticipated that technological innovations would further improve heat pump performance and reduce their capital costs over the next decade (LCICG, 2016). Also, the Energy Technologies Institute (ETI, 2018b) suggested that the capital costs of the UK's district heating networks could decline by 30–40% through improved designs and innovative solutions. Nonetheless, there are competing technologies such as biogas and hydrogen, and the future market development of heat pumps and district heating in the UK may be affected by the technical development and market development of these competing technologies.

Additionally, feasibility studies have been carried out in the UK to evaluate large heat pumps for different purposes, such as industrial heating and food production (Star Refrigeration, 2019). However, examples of the application of large scale heat pumps for residential heating are still very scarce in the

UK's district heating schemes, with very inadequate publicly available monitored data due to privacy and commercial sensitivities, and this restricts empirical studies in the UK. The size of heat pumps and district heating networks is rarely well-defined in the existing literature, but these are vital factors to assess their costs and explore how dwellings, heat pumps, and district heating networks are connected and operated. Based on empirical energy consumption data analysed in Chapter 3, this chapter presents techno-economic assessments to evaluate the trade-offs between different approaches to utilising electric heat pumps in district heating networks at different scales and to appraise their comparative economic and environmental advantages.

4.3 Methodology

Quantitative analysis of data and techno-economic modelling are conducted in this study to explore topological configurations to integrate buildings, heat pumps and district heating networks from the individual to the district level. This chapter analyses heat pumps and district heating networks at different scales that connect different dwellings and occupant diversities. A techno-economic model is built to explore how to utilise electric heat pumps and evaluate the economic and environmental trade-offs between the four topological configurations that integrate electric heat pumps in district heating networks (as introduced in Section 4.1.1, page 141).

Three main types of data are used to construct the model and address the secondary subsidiary research question of this thesis: heat demand in dwellings; heat pumps and district heating technology parameters; and technology costs, gas and electricity costs and carbon taxes. The following subsections explain the frameworks and components of the techno-economic model, as well as key data inputs and assumptions for the model and their sources. The key technology and cost data inputs, assumptions and equations used in the model are outlined in Section 4.3.4 (page 181), and additional data inputs such as projected future gas and electricity costs can be found in Appendices.

The techno-economic assessment model is designed to simulate individual and aggregated heat demand at various types of dwellings and different scales based on the empirical analysis of smart meter datasets and to calculate the costs and carbon emissions to meet heat demand through the application of electric heat pumps and district heating networks. This model does not simulate all the components of a district heating system or evaluate the state of a district heating system every hour of its lifetime, but it examines the most important variables which could affect the overall technical performance or costs of heat pumps or district heating networks, such as peak demand, sizes of heat pumps and district heating pipes, and operating temperatures. Then, this model evaluates the costs and carbon emissions associated with different topological configurations to utilise heat pumps in district heating networks. It compares the results among different ways to utilise heat pumps in district heating networks or individual dwellings, as well as a reference case that heat is supplied by individual gas boilers.

In brief, the techno-economic model works in three stages:

1. Quantifying heat consumption in dwellings and networks;
2. Modelling heat generation, transmission and distribution by heat pumps and district heating networks;
3. Evaluating costs and emissions to meet heat demand.

First, results from smart meter data analyses (Chapter 3) are used to quantify the hourly and annual domestic heat demand of individual dwellings from district heating networks at different scales. Furthermore, results of demand diversity analyses are used to determine the hourly peak heat demand and the sizes of heat generation capacities and district heating transmission and distribution systems.

Second, the model (discussed in Section 4.3.2, page 159) explores the operation and performance of four topological configurations to utilise heat pumps and district heating networks, by examining the COP of different types of heat pumps and heat loss from different district heating pipes and evaluating the overall energy consumption and heat generation. Meanwhile, the model investigates the district heating networks' performance based on various operational conditions, such as different flow and return temperatures and heat pump efficiencies, and then assesses heat losses and the overall network efficiencies associated with the various topological configurations at different scales.

Lastly, the model assesses the costing structures of different topological configurations to utilise heat pumps to meet domestic heat demand, including initial investment costs and levelised costs, and it then evaluates their associated carbon emissions (discussed in Section 4.3.3, page 173).

4.3.1 Techno-economic assessment

Techno-economic assessment (or techno-economic analysis, TEA) is an approach to cost-benefit analysis while additionally evaluating technical and economic performance, risks and uncertainties of specific projects or technologies (Lauer, 2008). It combines process modelling and economic evaluations to compare investment and operation related costs with benefits earned. In the field of energy, techno-economic models have been applied as essential implements for long-term technology performance assessments, energy output valuations, and system optimisations (Cui, 2019). For instance, TEA compares different technologies that offer the same services, evaluates economic feasibility and cash flows over time, and forecasts the likelihood of future technological applications and developments. This study applies the techno-economic approach to assess the key technical and cost components of heat pumps and district heating networks to evaluate their long-term cost competitiveness and emission reduction potentials.

In general, the techno-economic assessment considers a range of economic calculation methods, such as static cost-benefit assessment, annuity calculations, cash flows, net present value (NPV), and internal rate of return (IRR) (Lauer, 2008). Different methods can be tailored and applied based on specific projects or questions. This chapter applies the levelised cost method as the leading economic valuation procedure together with the overall investment costs to evaluate different topological configurations that utilise heat pumps and district heating on different scales. The levelised cost method is an adaptation of NPV calculations based on the discounted cash flow (DCF) system under specific technical and economic assumptions (IEA et al., 2015).

The levelised cost of energy is sometimes referred to as the life cycle cost of energy plants (DECC, 2013a), because it considers all cost elements of energy generating technologies over their operating life cycle at the plant level, from initial designing, planning, installation, operation, and energy generation, to site decommissioning and waste management. It is the ratio of the NPV of the overall costs of a technology over the NPV of the total amount of energy generated by this technology. Hence, the value of future costs and outputs is discounted. The levelised cost of energy characterises a plant's average lifetime cost per MWh or kWh of energy production. The levelised cost of energy can be categorised based on the types of energy or service generated, such as the levelised cost of electricity or the levelised cost of heat.

The levelised cost method commonly includes two key cost categories. These are initial investment related costs and operation related costs (IEA et al., 2015). The initial investment relative cost comprises costs to the investors for project design, development, financing, insurance, construction, and infrastructure establishment. Operation related costs include operation and maintenance costs, fuel costs, labour costs, and others, such as costs incurred by monitoring, licences, and waste management. Additionally, Lauer (2008) proposed that in economic evaluations of new technologies, the major obstacles are the ability to obtain realistic data of investment costs, and to forecast the contingencies (such as non-expected costs).

Some researchers have argued that the levelised cost method needs to improve the transparency and comparability of its technologies' cost inputs and assumptions (Khatib, 2016). Some studies have also criticised this method because it does not always consider externalities or the impact of technologies on the broader energy systems in the long term (Ouyang and Lin, 2014; Rhodes et al., 2017). Nevertheless, the levelised cost of energy is widely used to evaluate alternative electricity generation technologies at the national scale in many countries (Larsson et al., 2014; Hansen, 2018). Moreover, the levelised cost method is adopted by the OECD and IEA (2010; 2015) to assess the cost of electricity generation and its implications for policy makers regularly. However, some studies have pointed out that there are only a few applications of the levelised cost method in the heating sector (Sandvall et al., 2017; Hansen, 2019).

4.3.2 Heat pumps and district heating network modelling

The three main elements in the model and their associated technical and economic features are summarised in the flow chart, outlined in Figure 4.2:

1. **Demand analysis**: empirical quantification of heat consumption in dwellings and their peak demand;

2. **Technology modelling**: heat generation and distribution modelling through different heat pumps and district heating networks topological configurations;

3. **Economic evaluation**: comparative economic appraisals of alternative options to meet heat demand through various topological configurations of heat pumps and district heating networks. Detailed data inputs and technical assumptions used in the model are outlined in Section 4.3.4.

Key results of the techno-economic model are highlighted in yellow in Figure 4.2 to evaluate the technical, economic and environmental trade-offs among different topological configurations (highlighted in green) to utilise heat pumps and district heating networks to meet domestic heat demand, compared to a reference case which heat demand is entirely supplied by a gas boiler.

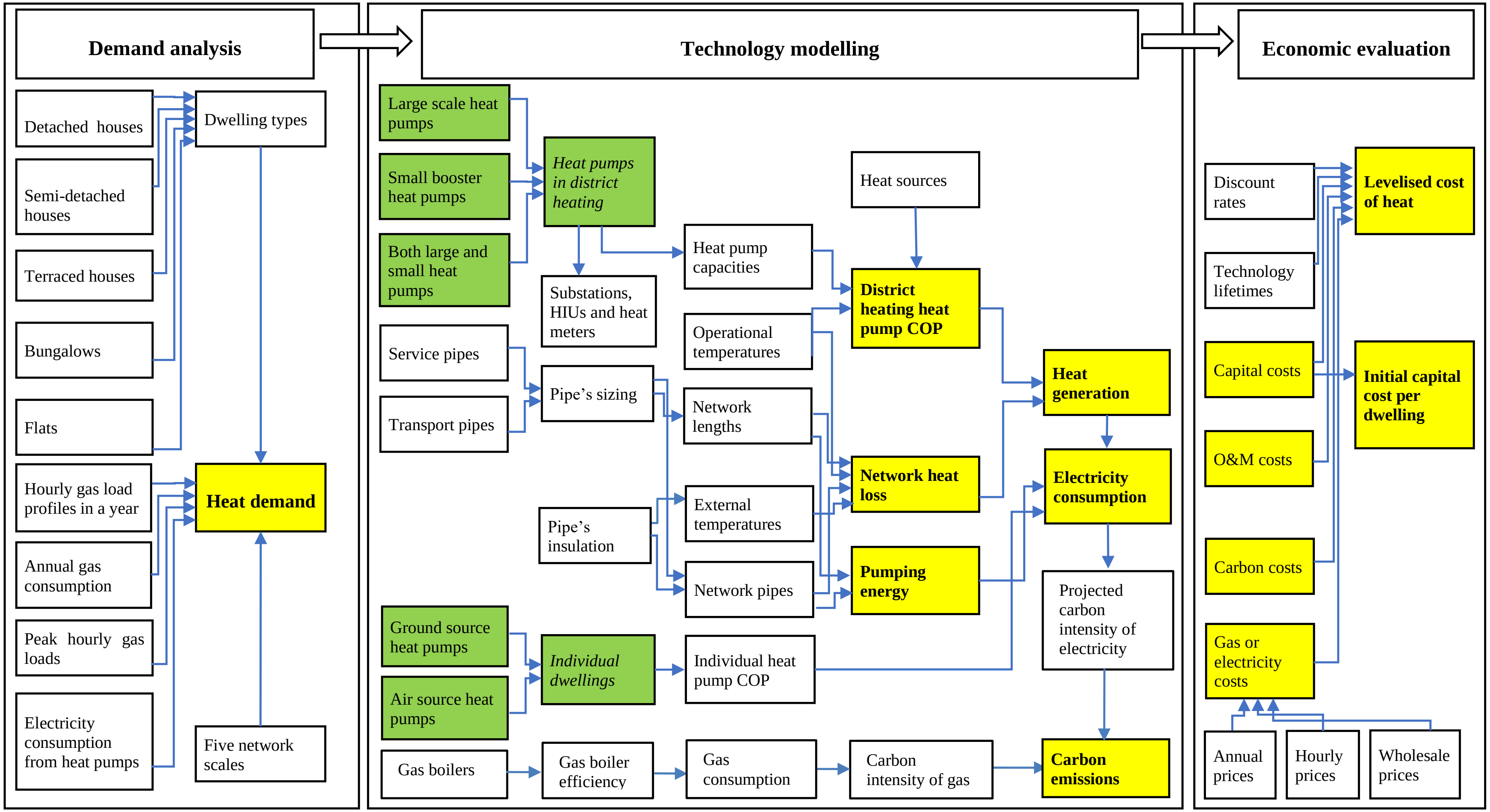

Figure 4.2: An overview of the framework of the techno-economic assessment model to evaluate the comparative advantages of various heat pump and district heating topological configurations.

4.3.2.1 Heat demand of district heating networks

For individual dwellings, evidence from smart meter field trials demonstrated that the annual demand for heat varies according to their types and ages (Section 3.4.2, page 103). Smart meter gas consumption results from Chapter 3 are converted to heat demand based on the average gas boiler efficiencies in the UK (ECUK, 2019). The average annual heating demand and peak demand for each dwelling type and age are quantified at the individual scale, so as to determine the generation capacities of individual ground source or air source heat pumps, as well as total heat generation.

Correspondingly, for district heating networks, the average annual heat demand is extrapolated from individual dwellings to estimate the overall annual heat demand for a group of dwellings at district levels according to dwelling types and the sizes of the networks. Aggregated hourly demand and the ADMD, in respect to different numbers of dwellings, are used to classify the maximum capacities of district-scale heat pumps and various components in district heating networks, such as the size of substations and main transport pipes. The overall heat generation at the district scale is calculated as the sum of aggregated heat demand from dwellings and district heating network loss. It is common that district heating networks connect, both domestic and non-domestic buildings. Due to data availability, this study only considers energy demand from dwellings.

4.3.2.2 The Coefficient of Performance of heat pumps

The efficiency, often described as the Coefficient of Performance (COP), of an electric heat pump is determined by the ratio of heat generation to its electricity consumption (W), which is affected by the heat pump's specific operational conditions and system boundaries (Nordman and Zottl, 2011). The maximum theoretical efficiency of a heat pump is described by the Carnot efficiency, which is dependent on the temperature differences between the hot and cold reservoirs (Q_{hot} and Q_{cold}) which the heat pump operates under. Equation (4.1) displays the Carnot efficiency of a heat pump used for heating: the performance of a heat pump is maximised if the temperature difference between the delivered temperature (T_{hot}) and heat sources (T_{cold}) is minimised. However, in reality, there are many factors that can affect the efficiency of a heat pump, such as heat pump designs, types of refrigerants or maintenance conditions, and practical operating temperatures. Therefore, a system efficiency factor (η in Equation (4.2)), ranging from 0.4 to above 0.7, is commonly used to calculate the practical COP of a heat pump in previous studies (Meggers et al. 2010; Wyssen et al. 2010; Gasser et al. 2017). This model considers the COP as the efficiency for heat pumps only, and it does not consider auxiliary units such as back-up heaters. Additionally, Section 4.4.1.2 (page 196) and Section 4.4.2.2.1 (Figure 4.13, page 210) explore the impact of changes in operating temperatures on heat pumps COPs, and the tornado graphs in Section 4.4.3.2 (page 261) quantify the impact of variations in heat pumps' system efficiency factor η on the overall electricity consumption and levelised cost of heat.

$$COP_{Carnot} = \frac{Q_{hot}}{W} = \frac{Q_{hot}}{Q_{hot} - Q_{cold}} = \frac{T_{hot}}{T_{hot} - T_{cold}} \tag{4.1}$$

$$COP_{practical} = \eta \cdot COP_{Carnot} \tag{4.2}$$

The amount of electricity (kWh) consumed by heat pumps is calculated according to different types of dwellings and scales of district heating networks based on Equation (4.3). This study assumes that there is no distribution heat loss or transport pumping energy associated with ground source or air source heat pumps installed inside of individual dwellings. Moreover, the total amount of heat generated from heat pumps at different scales of district heating networks is the sum of heat demand from the total connected dwellings and heat loss from the distribution networks. Furthermore, carbon emissions associated with heat generated by domestic heat pumps and heat pumps in district heating networks are calculated based on the carbon content of the electricity grid estimated by the UK government (ECUK, 2019).

$$\begin{aligned} &Electricity\ consumption \\ &\quad = \frac{Heat\ demand\ in\ dwellings + heat\ loss}{Heat\ pump\ efficiency} \\ &\quad + pumping\ energy \end{aligned} \tag{4.3}$$

$$\begin{aligned} &Carbon\ emission \\ &\quad = Electricity\ consumption \\ &\quad \times carbon\ intensity\ of\ electricity \end{aligned} \tag{4.4}$$

4.3.2.3 District heating heat loss and pumping energy

Heat loss (W/m) and pumping energy (W/m) through heat transmission and distribution are modelled based on different sizes and lengths of district heating pipes under different operating temperatures, as shown in Equations (4.5) and (4.6).

$$Heat\ loss\ from\ pipes\ = \frac{2\ \pi\ L\ (ti - to)}{\left[\frac{ln\left(\frac{ro}{ri}\right)}{k}\right] + \left[\frac{ln\left(\frac{rs}{ro}\right)}{ks}\right]} \tag{4.5}$$

Where:

L is the length of district heating pipes

ti is the water temperature inside the district heating pipes

to is the ambient temperature outside the district heating pipes

ro is the outside radius of district heating pipes

ri is the inside radius of district heating pipes

k is the thermal conductivity of district heating pipes

rs is the outside radius of insulation

ks is the thermal conductivity of insulation material

$$Pumping\ energy = (\frac{\dot{m}}{e^c})^{\frac{1}{\alpha}} \times A \times V \tag{4.6}$$

Where:

$\dot{m}$ is the mass flow rate of hot water in district heating pipes

e^c and $\frac{1}{\alpha}$ are the constants specific to pipe types. These are calculated based on the pressure loss and mass flow rate for various sizes of pipes, detailed in Appendix C.

A is the cross-sectional area inside of district heating pipes

V is the velocity of hot water

4.3.2.4 District heating pipe lengths

The overall network heat loss and pumping energy are directly affected by the length and size of district heating pipes. This model assumes that two types of district heating pipes are used: the main transport pipes which are buried underground to transfer heat (via hot water) from the energy centre to a group of dwellings, and the service pipes (internal pipes) which deliver heat from main transport pipes to each individual dwelling. For modelling purposes, this study adopts the average length of internal pipes per dwelling of existing heat networks in the UK suggested by DECC and AECOM (2015), and the lengths of transport pipes are estimated based on heat network examples on different scales.

Without conducting detailed heat mapping and route designing, estimating the distance between heat generation (energy centres) and heat consumption (dwellings) and the length of transport pipes is highly uncertain. This is because the network layout and length of transport pipes can vary significantly depending on a combination of local conditions, including building types, property ownership, local geography, heat source locations, or planning and construction restrictions. There are limited heat network examples from the UK to provide data benchmarks for the length of transport pipes, particularly for large networks. According to AECOM and DECC (2015), the majority of the UK's district heating networks are considered small or medium, with an average of 39 to 190 dwellings per network. This report stated that heat network connections and configurations were the key areas of network capital cost sensitivity, depending on the size and nature of the network schemes. The report also revealed that the overall internal service pipe lengths (13.3 m on average) could be significant at around ten times greater than the networks' overall transport pipe lengths.

For small district heating networks, it is common that the energy centres (or heat sources) are relatively close to the dwellings, while large schemes serving a great number of customers may have much longer transport pipes, and the overall length of transport pipes could become highly uncertain as the system could become more complex. A small district heating network may only connect multiple dwellings from one or a few buildings, whereas larger schemes could connect multiple real estate developments and the network components could be dispersed. For example, as one of the UK's largest networks, the London Olympic Park district heating and cooling networks have approximately 16 km of distribution pipes for heating and 2 km of cooling pipes (Ramboll, 2011).

To estimate the total length of transport pipes of district heating networks at different scales, this study gathered evidence from existing networks or proposed networks' feasibility studies. The lengths of transport pipes from the network examples were treated as model input assumptions. A range of district heating networks were reviewed based on three main data sources: district heating schemes from the Heat Networks Planning Database (BEIS and Barbour ABI, 2021), projects that Heat Networks Delivery Unit

(HNDU) and Heat Networks Investment Project (HNIP) have worked with (BEIS, 2021), and heat mapping studies from the London Heat Map and the Decentralised Energy Master Planning programme (DEMaP) (Centre for Sustainable Energy, 2021). For each district heating scale defined in this study (Table 4.1, Section 4.1.2, page 143), a similar-sized district heating network was identified, except for the smallest scale (with less than 100 dwellings).

The length of transport pipes for the identified district heating scheme examples were mapped and measured. Based on the existing network maps or the proposed network layouts from their feasibility or energy plan studies, this study mapped and estimated the lengths of transport pipes for four scales of district heating networks using the distance measurement tool of the London Heat Map (Centre for Sustainable Energy, 2021). When an example network (at the same scale) had a different number of dwellings from the model assumptions, the length of transport pipes was proportionally re-scaled to the number of connected dwellings. For example, the mapped transport length of a medium heat network was approximately 753 metres for 464 dwellings, this number was upscaled to 811 metres and used as the assumed transport pipe length for a 500-dwelling network in the model.

The layouts of existing or proposed district heating networks corresponding to the defined district heating scales in this study are shown in Figures 4.3 to 4.7. The mapped total length of transport pipes for example networks and the input assumptions for the five heat network scales defined in this model are outlined in Table 4.2 (page 173). Based on the number of dwellings in the district heating networks, the total length of transport pipes is assumed to vary from 500 metres for a small heat network to more than 15 kilometres for the largest scale.

- **Small heat networks**

Heat networks servicing a small group of dwellings are sometimes defined as community heating instead of district heating. The ADE (2018) defines networks as community heating if they supply heat to multiple dwellings in one building, such as a block of flats. DECC (2013) studied 1,765 networks in the UK and found that 1,280 of them were defined as small with less than 100 residential properties. For small district heating networks, energy centres tend to be close to the consumers, and the transport pipes are commonly within hundreds of metres (Arup, 2011).

However, some small district heating networks could have much longer transport pipes if the energy centre is not close to its customers. For example, the Bicester district heating network installed over 2.4 km of transport pipes to connect 72 dwellings to its energy centre (Vital Energi, 2014). Therefore, even for small heat networks, transport pipe length could differ significantly case by case depending on the nature of the heat network. To quote a single meaningful figure for the smallest district heating network in this model, a 250 m transport distance with a total of 500 m of transport pipes (flow plus return) are assumed for a 100-dwelling district heating network.

- **Medium heat networks**

To estimate the transport pipe length of a medium heat network, the Shoreditch heat network was identified as a comparable candidate. The network was installed in late 2012 to serve 464 dwellings in the London Borough of Hackney. The layout of the Shoreditch heat network was obtained and mapped from the London Heat Map (Centre for Sustainable Energy, 2021) as shown in Figure 4.3, and the estimated network transport route was 753 m, measured using the distance measurement tool. To estimate the total length of transport pipes for a 500-dwelling medium district heating network, the mapped network route from the Shoreditch heat network was upscaled to 811 m, and the model assumes that a total of 1,622 m transport pipes, including both flow and return pipes, were used for a medium district heating network.

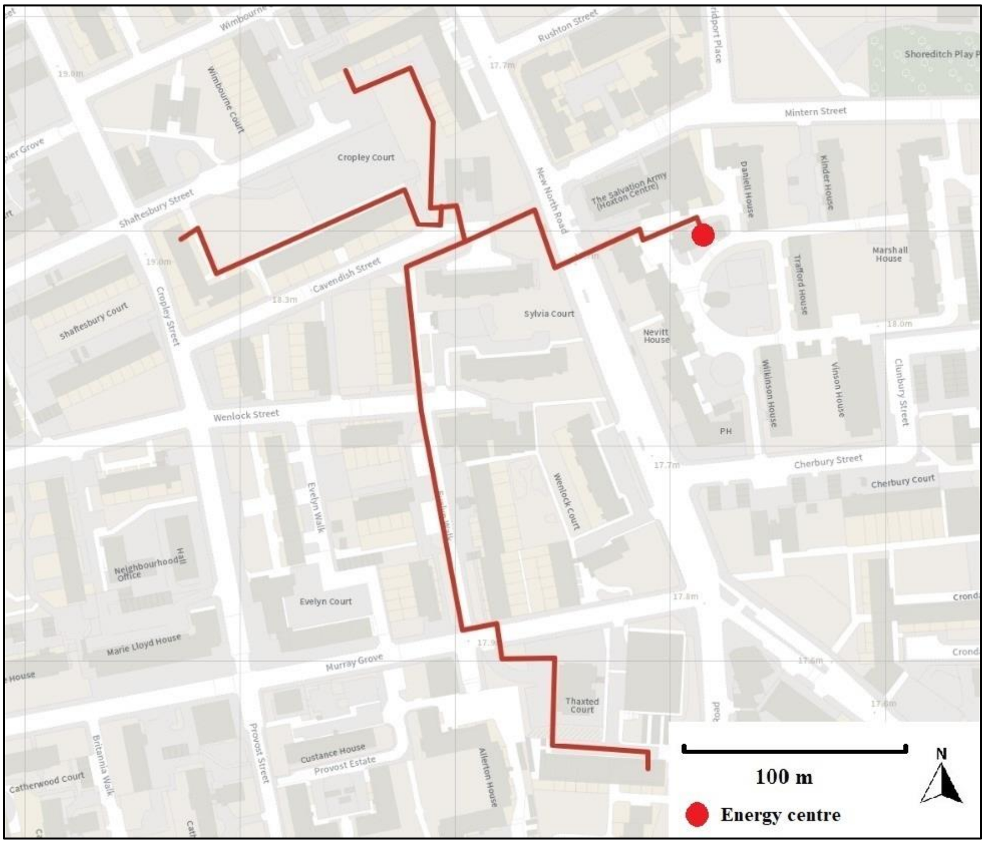

Figure 4.3: The network layout of the Shoreditch heat network.

- **Large heat networks**

Similarly, the network layout of the Catford district heating scheme was used to estimate the length of transport pipes for a large district heating network that serves 1,500 dwellings. The Catford district heating scheme was proposed as part of the Lewisham Energy Masterplan (Buro Happold, 2020). Figure 4.4 shows the proposed district heating network for the Catford region. Ramboll (2010a) conducted heat mapping and estimated the annual heat demand for potential district heating networks in the Catford region was 20,911 MWh. The network was proposed to meet the energy demand of about 1,500 residential units, with the potential to expand the network to over 3,500 dwellings and connect to the Lewisham hospital cluster (Buro Happold, 2020).

Using the same method as the Shoreditch district heating network, the length of transport pipes for the Catford district heating network was mapped and measured. It was estimated that around 3,180 metres of transport pipes were required for the Catford district heating network, and this number was applied as the model assumption for a 1,500-dwelling district heating network.

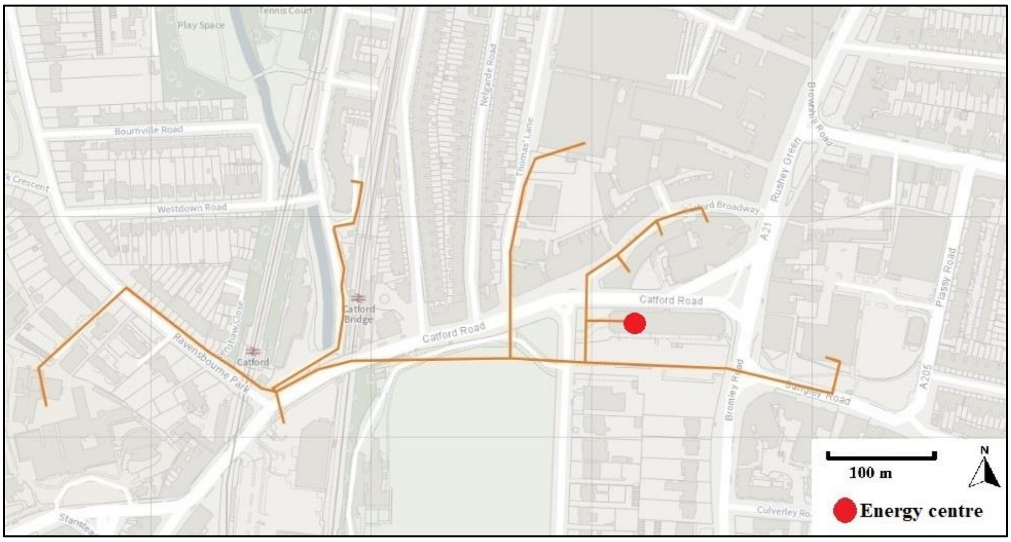

Figure 4.4: The proposed network layout of the Catford district heating network.

- **Single developments**

The proposed South Kilburn district heating network was used as an example to estimate the length of transport pipes for a district heating network with 2,500 dwellings (single developments scale). The London Borough of Brent proposed a regeneration masterplan for South Kilburn, and the South Kilburn Energy Strategy was proposed to develop a decentralised network for the area with about 2,650 residential units and a group of commercial properties (Ramboll, 2010b). The proposed district heating network layout was obtained from the London Heat Map (Centre for Sustainable Energy, 2021), as shown in Figure 4.5, and the total network length was measured. Approximately 5,120 metres of transport pipes (2,560 metres of network route) for this network were proposed, and the number was downscaled to 4,830 metres for a 2,500-dwelling district heating network for modelling purposes.

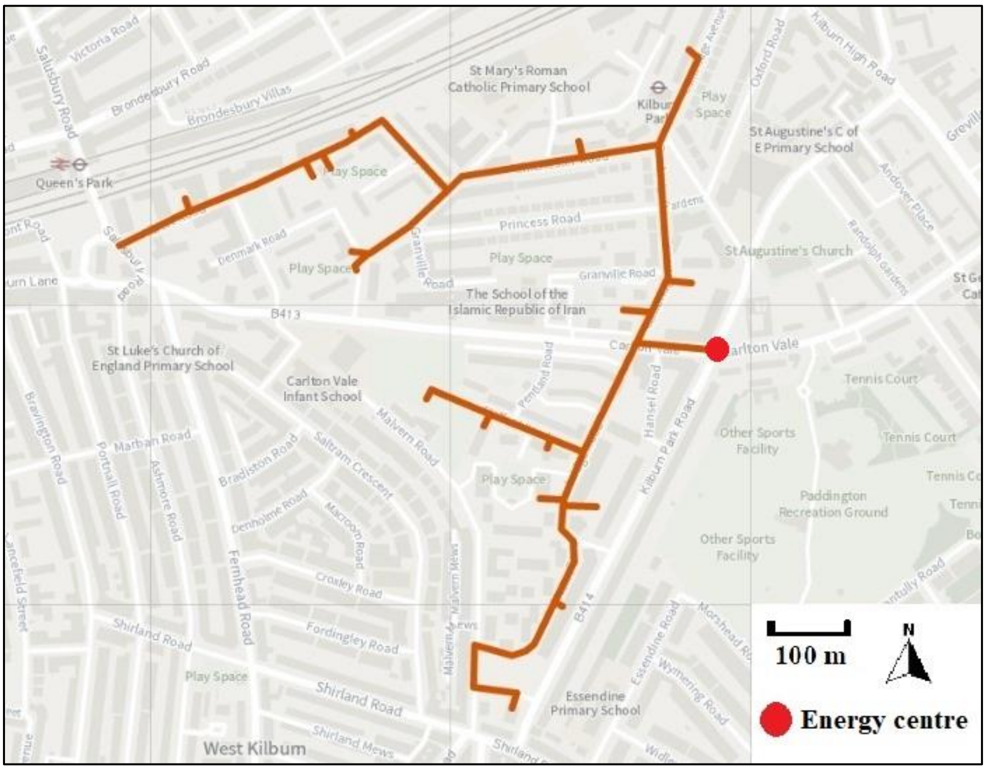

Figure 4.5: The proposed network layout of the South Kilburn district heating network.

- **Medium multi-developments**

The design of a district heating network could become more complex as the network scale grows; therefore, affecting the transport pipe lengths. Large-scale district heating networks may be developed in phased processes over years by several parties. Network schemes may become intricate and multiple organisations and energy centres may be involved (DECC and AECOM, 2015). Moreover, multiple smaller schemes may amalgamate over time to join connections and form larger schemes. To estimate the length of transport pipes for the largest scale of district heating defined in this study, the proposed Colindale district heating network was identified. Commissioned by the London Borough of Barnet and the Greater London Authority (GLA), Ramboll (2014) undertook a decentralised energy masterplan for the Colindale regeneration area.

The Colindale regeneration area is predominantly residential buildings, and the regeneration plan aims to deliver at least 10,000 dwellings for this area (Ramboll, 2014). The coordinated district heating network scenario proposed the interconnection of the major new development clusters into a single district heating network, with multiple potential energy centres. Due to the complex nature of district heating at such large scales, multiple potential network routes were assessed. An early provisional network route was evaluated by Ramboll (2014), with around 5.9 km of network route being proposed, as shown in Figure 4.6. A later network design was obtained from the London Heat Map (Centre for Sustainable Energy, 2021), and the network route was mapped to estimate the length of transport pipes, as shown in Figure 4.7. Using the distance measurement tool, approximately 7,650 metres were estimated for the network’s transport route, and this number was used as an input assumption for the largest scale of district heating network in this study, supplying heat to 10,000 dwellings.

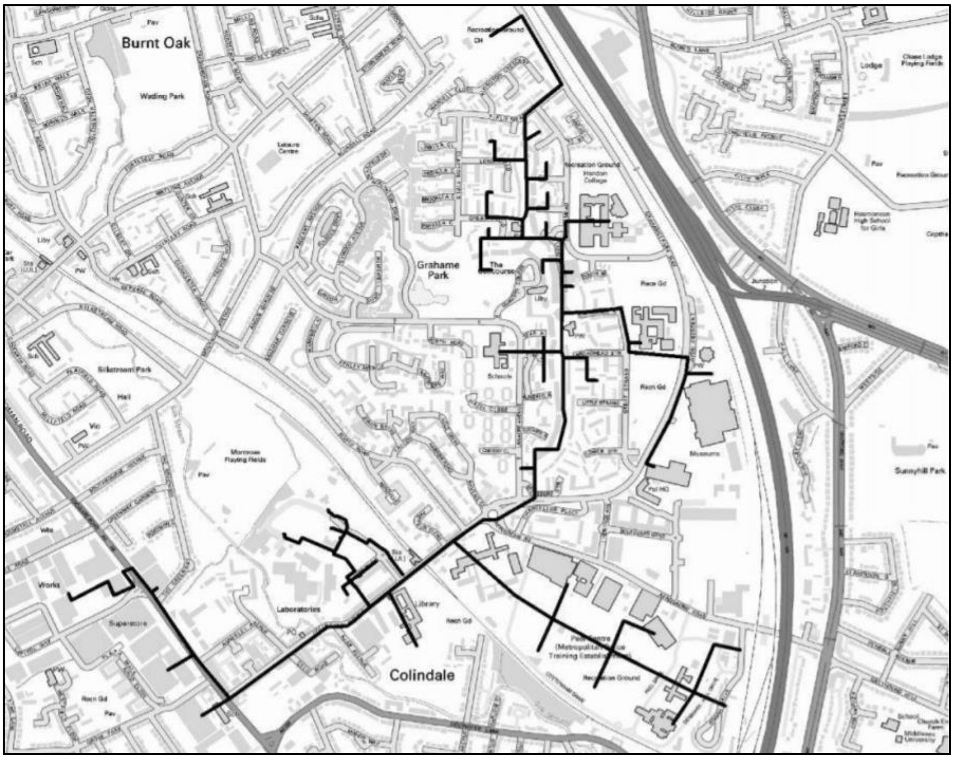

Figure 4.6: Provisional network route by Ramboll (2014) for the Colindale district heating network, with 5,907 metres of network route.

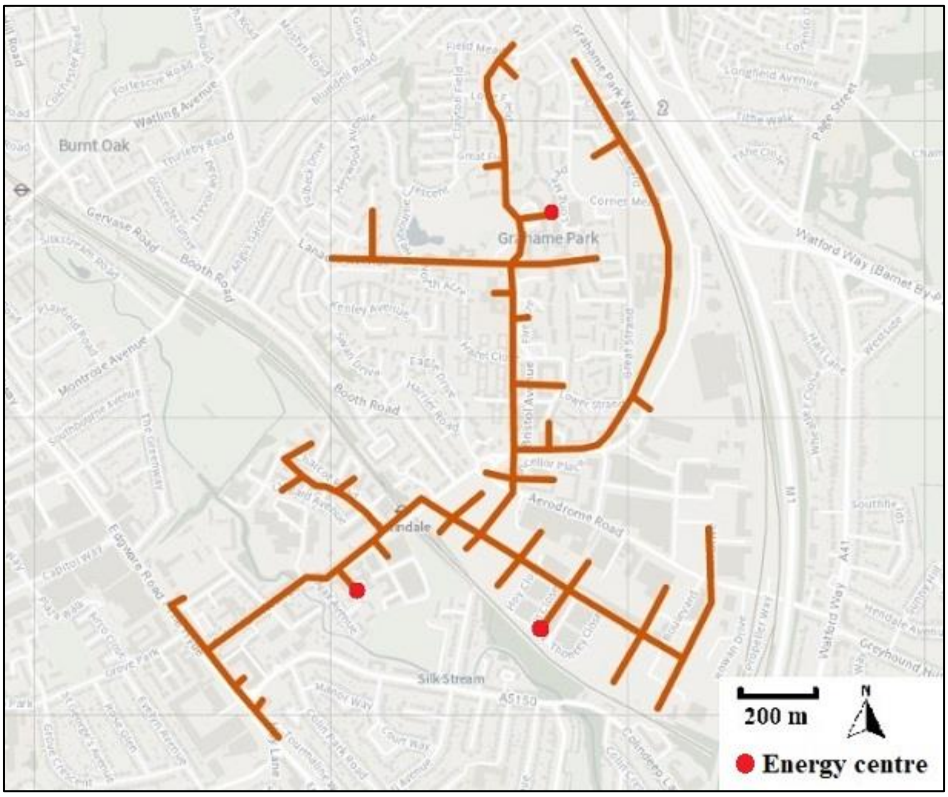

Figure 4.7: The proposed network layout of the Colindale district heating network from the London Heat Map.

Table 4.2: The assumed length of transport pipes in the five defined district heating scales.

District heating scale	Number of dwellings	Example networks with similar sizes	Network route, mapped (m)	Length of transport pipes, model assumption (m)
Small heat networks	100	NA	NA	500
Medium heat networks	500	Shoreditch district heating network (464 dwellings)	753	1622
Large heat networks	1500	Catford district heating network (≈ 1500 dwellings)	1590	3180
Single developments	2500	South Kilburn district heating network (≈ 2650 dwellings)	2560	4830
Medium multi-developments	10000	Colindale district heating network (≈ 10000 dwellings)	7650	15300

Table 4.2 summarises different scales of district heating networks defined in this study, their corresponding existing or proposed heat networks, and the lengths of transport pipes assumed in the model. In practice, every district heating network has to be treated on an individual basis when deciding the types, sizes, layouts of district heating pipes based on a combination of factors. Due to the nature of district heating networks, there are significant uncertainties in costs and heat loss from transport pipes according to district heating network designs and installations. This study applies a set of assumed transport pipe lengths based on the existing or proposed example networks' transport routes. The uncertainties and impact of variations in the total length of transport pipes for the model are discussed in Section 4.4.3.1.4 (page 253). Using the same method applied by the IEA, NEA, and OECD (2015), transport pipe lengths were adjusted by ±50% to illustrate

the quantitative impact of pipe lengths on the overall levelised cost of heat (Figures 4.43 to 4.45, page 261) and the overall electricity consumption (Figures 4.47 to 4.49, page 264), as shown in the tornado graphs in Section 4.4.3.2.

4.3.3 The levelised cost of heat model

The levelised cost of energy method is particularly useful when comparing a range of different technologies which provide the same service, but with various technology lifetimes and cost structures. In order to compare the cost of different approaches to meeting domestic heat demand through utilising heat pumps and district heating via different topological configurations, the levelised cost of heat (LCOH) model is developed for the techno-economic assessment, supporting economic evaluations based on the levelised cost formulae as shown in Equations (4.7) and (4.8) below.

The economic evaluation assumes that all technologies are installed and started to generate heat in 2018, but with different technology lifetimes. It models the operations of heat pumps and computes different types of costs for heat generation and carbon emissions to meet domestic demand from the individual level to different scales of district heating. It draws upon the results from demand analysis and technology modelling. It obtains technology cost data from a diverse range of data sources to evaluate the economic and environmental trade-offs between different topological configurations to utilise electric heat pumps and district heating networks. Moreover, the uncertainties in model input assumptions and their impact on the study results are evaluated in Section 4.4.3 (page 240) through local and global sensitivity analyses.

$$LCOH = \frac{Net\ Present\ Value\ (NPV)\ of\ costs\ over\ technology\ lifetime}{Net\ Present\ Value\ (NPV)\ of\ heat\ produced\ over\ technology\ lifetime} \tag{4.7}$$

$$LCOH = \frac{\sum\left[\frac{Capital_t + O\&M_t + Fuel_t + Carbon_t)}{(1+r)^t}\right]}{\sum\left[\frac{MWh_t}{(1+r)^t}\right]} \tag{4.8}$$

The parameters in Equation (4.8) indicate:

$Capital_t$: Capital costs during the time period of t. These are investment related costs, mainly capital expenditure (CAPEX). It is the total cost to developers or investors of design, planning, finance, purchasing and installation of heat technologies, and the construction of infrastructure for heat transmission and distribution, plus administration and insurance for heating technologies to begin regular operations. Depending on the particular project and location, the capital cost may or may not include the cost of purchasing or renting land and buildings. This is a highly variable factor depending on individual cases. As the focus of this research is to study heating technologies; therefore, this model does not assess the costs associated with land or buildings.

Moreover, the capital cost in this model includes periodical costs of replacing parts of the technology or infrastructure, which is often assessed as a share of the initial capital investment. For example, the lifetime of a district heating network may be over 50 years, but the large scale heat pumps in this network may need replacement every 25 years. Accordingly, technology replacement costs are added to the capital cost according to the lifetimes of heat pumps.

$O\&M_t$: Operational and maintenance costs during the time period of t. These are operation related costs (OPEX), i.e. the costs of operating heating technologies. O&M costs commonly involve costs caused by regular technology maintenance and labour which are dependent on the complexity of the technology, and involve cleaning, overhauling, and servicing equipment. The O&M costs are usually either fixed annually or proportional to the amount of heat generated, while regular inspections and maintenance are needed for health and safety or insurance requirements.

Additionally, in this model, the O&M costs also consider other applicable costs, including monitoring, licences, and waste management. Some studies categorise fuel costs as part of the operational cost. However, this study treats fuel cost as a different type of cost.

$Fuel_t$: Fuel costs during the time period of t. These are costs incurred by supplying fuel (gas or electricity) to generate heat using different types of technology, as well as electricity costs associated with heat generation, transmission, and distribution in district heating networks. It is calculated based on the amount of fuel consumed during a certain period of time according to various types of heating technology. It is directly affected by the specific heating technology's generation capacities, efficiencies, and operations. It is difficult to estimate or predict fuel prices in the future; however, Lauer (2008) suggested that the best method is to consider negotiated contracts for fuel supply over the technology's lifetime. Unfortunately, this information is rarely publicly available.

This study considers gas and electricity prices in the UK, both of which are continually changing as a function of supply and demand, and are affected by a number of complex factors. This model utilises three types of prices to model electricity costs. Besides the projected annual prices by BEIS (2019d) as the baseline, this model also considers historical hourly retail electricity spot prices that have been paid by consumers in the UK (Octopus Energy, 2019), and hourly wholesale prices that were traded between over 300 buyers and sellers on Nord Pool's day-ahead market (Nord Pool, 2019). Section 4.4.1.2 (Figures 4.13 and 4.14) evaluates the impact of changes in electricity prices on the overall electricity costs from individual heating options, and their impact on the overall levelised cost of heat for different heat pumps and district heating topological configurations is further discussed in the uncertainty analysis of electricity prices section (page 245).

$Carbon_t$: Carbon costs during the time period of t. These are essentially carbon emission taxes associated with heat generation using different technologies. This study considers carbon tax as a type of cost. Although electric heat pumps do not emit carbon dioxide on-site, there are emissions associated with the electricity they consume during heat generation and distribution, if the electricity is not decarbonised.

The amount of carbon emissions is modelled based on electricity consumption, heat pumps COP, and the projected carbon intensity of the electricity. Similar to fuel prices, it is difficult to predict future carbon tax and carbon intensity of electricity, therefore, this model uses the projected values published by the government (BEIS, 2019e). However, in the light of the UK's adoption of the Net-Zero emission target (CCC, 2020), the future carbon prices are likely to be higher than the currently BEIS (2019e) projections. The impact of future changes in the carbon intensity of electricity on the overall carbon emissions from different heating options is assessed in the uncertainties in the projected carbon intensity of the electricity section (page 248).

r: The discount rate, and $(1+r)^t$ designates the discount factor during the time period of t. Discount rates are used to represent the time value of money in discounted cash flow analyses in order to calculate the net present value. The UK HM Treasury (2018) suggested a discount rate of 3.5% as the 'social rate of time preference' according to the Green Book, which is a guidance published by the UK Treasury on how to appraise policy programmes and investments.

The discount rate may change based on different investment environments. A discount rate of about 7% is commonly used in corporate assessments, while discount rates of 10% or above are often used for high risk technologies or investment conditions (IEA, 2010). This model uses 3.5% as a baseline corresponding to the discount rate set by the UK Treasury, and the impact of changes in the discount rate on modelling results is evaluated in the sensitivity analysis. Variations in the overall levelised cost of heat from the baseline assumption are illustrated in Section 4.4.3.1 (page 243).

MWh_t: The amount of heat generated during the time period of t, in MWh. This study assumes that domestic heat demand is entirely supplied by the studied heating options (gas boilers, heat pumps and district heating), and that there are no supplementary heating measures used, such as fireplaces or electric fan heaters. Additionally, for individual dwellings, this model assumes that heat generation is equal to heat demand, on the premise that there is no heat loss due to heat transmission or distribution within the individual dwellings.

4.3.3.1 Modelling boundaries

District heating systems can be technologically complex, with interactions between various sub-systems and components. The primary purpose of this study is to evaluate the comparative economic and environmental advantages of different applications of heat pumps, either through installing heat pumps individually or integrating heat pumps into district heating networks. This model does not simulate all the components of a district heating system or evaluate the state of a district heating system every hour of its lifetime. As the model framework illustrated in Figure 4.2 (page 160), this study models heat pumps and district heating networks' critical technical and economic components with an idealised setup, abstracted from real situations, to estimate the cost of heat and emissions from different topological configurations to utilise heat pumps and district heating networks. Limitations and reflections on the idealised levelised cost model are discussed in Section 5.4 (page 275).

District heating could be integrated with multiple sources to provide flexible heat supplies. It is commonly linked to electricity and gas systems via combined heat and power systems. As specified in Equation 4.8 (page 175), this model assesses heat pumps and district heating at the plant level, it models the operations and costs of heat pumps and district heating components that could be affected by different topologies to integrate heat pumps, via large centralised heat pumps or small booster heat pumps. This model addresses the costs and carbon emissions to install and operate heat pumps and district heating networks. Modelling of upstream electricity or gas networks is beyond the model boundaries, and electricity or gas costs are treated as exogenous variables, sourced from other studies.

Some elements are difficult to quantify or may not be differentiated by different topologies to integrate heat pump and district heating networks. For example, this model does not address all externalities and indirect costs, social impacts, land costs, or energy system balancing and management costs. Also, this model does not capture the impact of ownership of district heating systems on the levelised cost of heat.

Moreover, the costs to construct and operate district heating energy centres are treated beyond the model boundaries. Different operating strategies and topological configurations to integrate heat pumps into district heating networks may affect the technical performance and costs of heat pumps and distribution networks significantly. However, they may not be the dominating factors that affect the costs to construct energy centres. The costs to construct and operate energy centres may vary substantially based on local conditions, and to model such factors may require detailed data of a specific network, such as locations, land prices, and local development and construction restrictions. For example, Grosse et. al. (2017) reviewed nominal investment costs of large scale heating technologies in Europe and revealed that the costs to construct energy centres could vary from 0.1 M€/MW_{th} to 2.8 M€/MW_{th} based on a number of local factors.

Besides capital costs, the design and specification of energy centres are likely to have an important impact on district heating networks' O&M costs. Large district heating systems could open up a much larger landscape of operational strategies than small scale district heating networks or individual dwelling solutions. In the context of a large scale transition from fossil fuels to renewable energy at the national and international level, this is likely to have profound impacts on costs of heat supply compared with other solutions; but quantifying this would have required a level of modelling that were beyond what could be included in the scope of this PhD. Section 5.5 (page 279) discusses potential further research to explore beyond the modelling boundaries of this study, such as assessing the costs to construct energy centres via case studies of specific district heating projects.

4.3.4 Model data inputs and key assumptions

This section describes the key data inputs and assumptions of the techno-economic assessment model. It is challenging to produce a set of realistic data for heat pumps and district heating networks' technical and cost characteristics entirely based on empirical data, due to the relatively low uptake rates and immature supply chains of electric heat pumps and district heating in the UK, especially large scale heat pumps. This model uses heat pumps and district heating technical and cost data collected from various databases or previous technical and economic investigations. Further discussions on their uncertainties and impact on the model results are included in Section 4.4.3 (page 240).

First, data corresponding to the capital and O&M costs of heat pumps and district heating, and their performance, are gathered based on previous field trials, cost assessments, and governmental statistics datasets from the UK. Then industrial catalogues are used to determine the technical characteristics of heating technologies. Some model inputs are extrapolated or parametrised based on existing data, such as the aggregated peak demand of district heating networks or the length of transport pipes.

Additionally, in case the datasets are outdated or unavailable from UK sources, data based on existing or similar applications from the Danish Energy Agency (DEA, 2019) and Ramboll (DEA and Ramboll, 2018) are used with size factors. The DEA collaborates with energy engineering consultancy companies such as Energinet and Ramboll, and regularly publishes updated catalogues of technology and financial data regarding heat generation from individual heating technologies, as well as district heating networks (DEA, 2019).

4.3.4.1 Heat demand

This model assumes that the average annual heat demand of one dwelling is 14,303 kWh. This number is calculated from an average of 17,880 kWh gas consumption per dwelling among 8,466 dwellings monitored during the EDRP field trials, as well as an average of gas boiler efficiency (80%), a statistic taken from the National Statistics (ECUK, 2019). In terms of heat demand in different dwellings, gas consumption data from various types and ages of dwellings (Table 3.1, Section 3.4.2, page 103) are used to calculate the annual heat demand for individual dwellings. Results are shown in Table 4.3. This study uses smart meter data from individual dwellings heated by gas boilers as a proxy, and it assumes that heat demand is invariant to whether it is supplied by a boiler, a heat pump or a district heating network.

Heat demand for district heating networks (before considering heat loss) is calculated according to the average heat demand and number of dwellings assumed at different scales as defined in Table 4.1 (Section 4.1.2, page 144). Additionally, this model assumes that the aggregated peak heat demand and generation capacities are determined by historical peak demand under extremely cold weather conditions. Hence, district heating networks' peak hourly demand and the aggregated after diversity peak demand are quantified based on the scale of district heating networks and the ADMD per dwelling (Figures 3.22 and 3.23, Section 3.4.7, page 121) or district heating networks that are larger than medium heat networks (500 dwellings), the asymptotic ADMD per dwelling (Figure 3.24) is used to estimate peak heat demand and generation capacities of the networks, as shown in Table 4.4.

Table 4.3: Annual heat demand from different individual dwellings.

Dwelling type	Annual heat demand (kWh per year)	Dwelling age	Annual heat demand (kWh per year)
Detached	18514	Before 1919	19011
Semi-detached	15087	1919-1944	17359
Terraced	13527	1945-1964	14996
Bungalow	14243	1965-1980	13022
Flat	10350	After 1980	11950

Table 4.4: Total heat demand from different scales of district heating networks.

District heating scale	Overall annual heat demand (kWh)	Aggregated after diversity peak demand (kW)
Small heat networks	1430300	753
Medium heat networks	7151500	3680
Large heat networks	21454500	11040
Single developments	35757500	18400
Medium multi-development scales	143030000	73600

4.3.4.2 Data inputs and assumptions for individual heating technologies

The costs of installing individual heat pumps may change substantially according to a number of factors, including brands, manufacturers, types (heat sources), installation capacity, and efficiencies. This study investigates a group of cost data sources in order to investigate heat pump costs. Installed capacities and types of heat sources are commonly used as indicators to differentiate different types of domestic heat pumps. Mainstream domestic heat pumps installed in individual dwellings are usually either air source heat pumps or ground source heat pumps, and on rare occasions, water source heat pumps. The installation capacity of a typical individual domestic heat pump can range between 2 to 45 kW, and most of the UK's individual domestic heat pumps are under 25 kW (EHPA, 2019a).

The capital costs of domestic heat pumps from the RHPP and the domestic RHI datasets are obtained for this study. The RHPP (finished) and the domestic RHI (ongoing) are two main financial incentives that were introduced by the government to encourage households to adopt domestic low-carbon heat systems in the UK (Ofgem, 2018). Installation statistics from these schemes are collected and made publicly available in the National Archives (2019). According to the domestic RHI statistics (BEIS, 2019b), about 39,400 air source heat pumps and 10,300 ground source heat pumps were installed through the RHPP and domestic RHI schemes by June 2019, and the mean installed capacities for air source heat pumps and ground source heat pumps were 10.0 kW and 13.5 kW respectively. Moreover, these statistics also revealed that the average COP of heat pumps installed after 2014 was 3.3 for air source heat pumps and 3.8 for ground source heat pumps.

Due to commercial and household privacy concerns, the domestic RHI dataset only publicly released a processed version of capital costs data for domestic heat pumps installed between April 2014 and March 2017.

Nonetheless, the median capital costs data for domestic heat pumps installed before December 2018 were further aggregated into nine groups based on their installation capacities from less than 5 kW to 41-45 kW, whereas data collected in 2019 were kept private. Therefore, the data of heat pumps installed between April 2014 and March 2017 are used for this study, with a sample of 15,669 air source heat pumps and 4,374 heat pumps. The median capital costs data for heat pumps based on nine size groups are only used for comparison purposes due to the lack of data transparency.

Furthermore, Table 4.5 summarises the key technical and cost assumptions used in the model for individual domestic heat pumps versus gas boilers in individual dwellings. A gas boiler is used as the reference technology in this study. A typical condensing gas boiler has 15 years of lifetime, and the cost may range from less than £1,500 to over £4,500, depending on the brand and capacity, and the efficiency of a new gas boiler is typically around 85% to 95% (Pöyry, 2009; Delta-ee, 2012).

To calculate the COP of heat pumps based on Equation (4.2), this study assumes different system efficiency factors (η) for different types of heat pumps, with data obtained from previous literature (Meggers et al. 2010; Wyssen et al. 2010; Gasser et al. 2017), 0.5 for air source heat pumps and booster heat pumps, 0.55 for ground source heat pumps, and 0.7 for large heat pumps integrated into district heating networks. The size and cost of an individual heat pump may change significantly from one brand to another, and different dwellings may require different sizes of heat pumps. For modelling purposes, this study assumes that the installed capacities of an individual air sources heat pump and a ground source heat pump are 10.0 kW and 13.5 kW, and their associated costs are taken accordingly from the dataset published by the RHI (BEIS, 2019b).

Table 4.5: Key technical and cost assumptions of modelled individual heating technologies.

Technology assumption	**Gas boiler**	**ASHP**	**GSHP**
Capital cost (£/kW)	70	880	1400
Technology size (kW)	30	10	13.5
O&M cost (£/year)	180	90	75
Baseline discount rate	3.5%	3.5%	3.5%
Efficiency/COP (%)	90%	Equation (4.2)	Equation (4.2)
System efficiency factor η	NA	0.50	0.55
Technology lifetime (year)	15	20	20
Carbon intensity (kg/kWh)	0.184	BEIS projection	BEIS projection
Data sources	Pöyry (2009); Wyssen et al. 2010; Delta-ee (2012); Gasser et al. (2017); HM Treasury (2018); BEIS (2019b; 2019d).		

4.3.4.3 Data inputs and assumptions for heat pumps and district heating networks

District heating only contributes to a very small proportion (2%) of the total heat demand in the UK (ADE, 2018), and the applications of large or small heat pumps in district heating networks have not been broadly commercialised. Therefore, there is little publicly available empirical data regarding the costs of large scale or small booster heat pumps in district heating networks, or how they have operated in the UK. Nevertheless, there are demonstration projects which offer technical and cost characteristics as verified examples of large scale heat pump applications in district heating networks, as well as industrial sectors in Europe (Averfalk et al., 2017; David et al., 2017; EHPA, 2018a). Based on these examples from European countries and recorded data from existing domestic and non-domestic heat pumps installed in the UK, it is possible to estimate the costs of large scale heat pumps by following the relationship between the size and the cost of heat pumps. Furthermore, the costs of small scale (less than 5kW) heat pumps may provide insights on the costs of small booster heat pumps which can be connected to the low temperature district heating networks.

Although there are a number of published costs of large scale heat pumps (larger than 100kW) in district heating networks, these costs differ significantly according to different data sources, ranging from less than €600/kW (DEA, 2019) to over £1700/kW (DECC and the Sweett Group, 2013). Moreover, much of the cost data lacked clarification in terms of whether the studied heat pumps were used to supply heat to domestic or non-domestic buildings, as well as being ambiguous regarding heat sources. Additionally, there is a tendency showing that the capital cost of large scale heat pumps has reduced continuously over recent decades, and the cost is expected to keep decreasing in the future (DEA, 2019), as heat pump technology improves, and the market develops.

According to previous studies, supply-chain assessments conducted by Pöyry (2009) NERA and AEA (2009) showed that the upfront cost of large scale heat pumps was more than £1,300/kW ten years ago. In contrast, recent RHI statistics (BEIS, 2019b) show that of 254 large scale water source or ground source heat pumps installed between 2011 and 2019, the lower quartile capital cost has dropped below £900/kW. Additionally, empirical costs estimated by Ramboll and DEA (2019) based on Danish district heating networks suggested that the upfront costs of large heat pumps integrated into district heating networks was €660/kW. Therefore, this model assumes two costs for large scale heat pumps integrated into district heating networks: £1,000/kW for heat pumps that are smaller than 5 MW and £600/kW for heat pumps that are larger than 5MW. Table 4.6 displays the capital, O&M and replacement costs and baseline assumptions incorporated in the techno-economic model for large scale and small booster heat pumps utilised in district heating networks.

Table 4.6: The baseline data inputs and assumptions for large scale and small booster heat pumps in district heating networks.

Technology assumption	**Unit**	**Large heat pumps**	**Small booster heat pumps**	**Data source**
Heat pump capital cost	£/kW	600/1000	1500	BEIS (2019b); DEA (2019)
Technology size	kW	variable	less than 5kW	
Heat pump O&M cost per year	£	£2000/MWh	£90	DECC and AECOM (2015)
Heat pump lifetime	Year	25	20	DECC and AECOM (2015)
Heat pump efficiency (COP)	%	Equation (4.2)	Equation (4.2)	
System efficiency factor η		0.70	0.50	Meggers et al. (2010); Wyssen et al. (2010); Gasser et al. (2017)
Technology replacement cost (%)	%	50%	50%	DEA (2019)

This study proposed three district heating topological configurations regarding how individual dwellings, heat pumps and district heating networks are connected under different operational temperatures. District heating operational temperatures may vary according to specific networks, and they can be altered according to the networks' heat demand and operational strategies. This study assumes two sets of baseline operational temperatures: 80 ℃ and 60 ℃ are used as the flow and return temperatures for high temperature district heating networks with large scale heat pumps (Topology 2), and 30 ℃ (flow) and ground ambient temperature (return) are assumed for low temperature district heating networks with individual booster heat pumps (Topology 3 and 4).

Furthermore, Table 4.7 and Table 4.8 present a summary of key technical features, additional costs, and baseline assumptions used in the techno-economic model, for various components of district heating networks. In terms of data input for heat transmission and distribution, a set of benchmarks or typical values of district heating costs and operations is gathered from an empirical study conducted by DECC and AECOM (2015). This was taken from 14 networks that were considered to be representative of district heating schemes in the UK.

The DECC and AECOM (2015) report investigated operational features and costs of various components in district heating networks, such as capital and operational costs of district heating infrastructure, HIUs and substations, heat loss, and carbon emissions. However, this report did not gather detailed operation data and costs for district heating pipes, and the majority of current operating heat networks in the UK are considered small networks. Therefore, additional data associated with the technical features and costs of district heating pipes are collected from data sources which examined European district heating networks.

To model district heating pipes, this study obtained a set of detailed technical data for different types of district heating pipes from various sources, including district heating pipe manufacturers (Brugg and Logster), engineering consultancy companies (DEA and Ramboll), and previous modelling studies (4GDH studies). The techno-economic model of this study differentiates district heating pipes and their technical characteristics according to their sizes based on the European Standard (BS EN13941, 2019), ranging from DN15 (110mm diameter) to DN300 (500mm diameter). However, it is difficult to find detailed and reliable cost data for district heating pipes in the UK due to the fact that this is considered commercially sensitive data, and corporations may apply different pricing schemes when estimating pipe prices. Therefore, this study utilises district heating pipe costs from the DEA and Ramboll (2018) based on empirical data from German and Danish district heating networks, and prices are converted from euro (EUR) to pound sterling (GBP) based on an exchange rate of 1:1.1, as shown in Table 4.8.

Table 4.7: Key baseline data inputs and technical assumptions for components of district heating.

Technology assumption	**Unit**	**Value**
Ground ambient temperature	℃	10
The average length of service pipe per dwelling	m	13.3
Baseline operating temperature flow	℃	80
Baseline operating temperature return	℃	60
Cost of domestic HIUs per dwelling	£	1075
Heat meter cost per building	£	3343
Heat meter cost per dwelling	£	579
Heat meter maintenance	£/MWh	3.4
Heat network maintenance	£/MWh	0.6
HIUs maintenance cost	£/MWh	9
Labour cost for metering, billing and revenue	£/MWh	16.9
Network lifetime	year	50
Substation cost	£/kW	35
Thermal conductivity of pipe insulation	W/mK	0.03
Thermal conductivity of pipe tube	W/mK	401
Thickness of insulation	m	0.05
Data sources	DECC (2013); DECC and AECOM (2015); BEIS (2020); DEA (2019).	

Table 4.8: Size and cost data of different district heating pipes, data from the DEA and Ramboll (2018).

District heating pipes				**Cost (including design, administration and installation)**	
	Ri (pipe inside radius)	Ro (pipe outside radius)	Rs (outside radius of insulation)	Investment costs (price in 2018)	
Unit	m	m	m	€/m	£/m
DN15	0.009	0.011	0.061	432	393
DN20	0.011	0.013	0.063	442	402
DN25	0.015	0.017	0.067	456	415
DN32	0.019	0.021	0.071	496	451
DN40	0.022	0.024	0.074	517	470
DN50	0.027	0.030	0.080	551	501
DN65	0.035	0.038	0.088	607	552
DN80	0.041	0.044	0.094	675	614
DN100	0.054	0.057	0.107	783	712
DN125	0.066	0.070	0.120	924	840
DN150	0.080	0.084	0.134	954	867
DN200	0.105	0.110	0.160	1343	1221
DN250	0.132	0.137	0.187	1760	1600
DN300	0.156	0.162	0.212	2124	1931

4.4 Results and discussions

This section discusses the results of the techno-economic assessment. This section first evaluates individual heating technologies installed in individual dwellings. Section 4.4.1 compares individual air source and ground source heat pumps to a gas boiler in relation to meeting heat demand in different types of British dwellings and discusses the impacts of different electricity pricing schemes on the overall electricity costs. Following this, the model evaluates the balance between the levelised cost of heat and carbon emissions for different individual heating measures.

This section then explores the potential approaches to utilising large centralised or small individual booster heat pumps in district heating networks on five scales and their comparative advantages. Section 4.4.2 assesses the technical performance of district heating networks under different operational conditions at different scales, with an assessment of the trade-offs between heat loss and pumping energy for different sizes of district heating pipes. It then appraises the economic and environmental benefits or drawbacks according to different topological configurations for utilising heat pumps in district heating networks. This subchapter also discusses the uncertainties of model inputs and assumptions via sensitivity analyses in Section 4.4.3.

4.4.1 Individual heating technologies in individual dwellings

Currently, installing individual heat pumps to replace gas boilers (Topology 1) is the most common way to use heat pumps in the five typical types of British dwellings. This subchapter discusses the capital costs to install individual heat pumps according to different technology capacities. Besides, it evaluates the levelised cost of heat and different cost components for a gas boiler, an air source heat pump, and a ground source heat pump over their technology lifetimes. Furthermore, by comparing with a gas boiler, this subchapter quantifies the potential to reduce carbon emissions from domestic heating through high-efficiency heat pumps and utilisation of projected decarbonised electricity.

4.4.1.1 Capital costs of heat pumps and their capacities

According to the RHPP and the domestic RHI statistics (BEIS, 2019c), the majority of heat pumps installed through these two schemes have an installed capacity of less than 20 kW, while the total number of installed air course heat pumps was almost four times higher than that of ground source heat pumps as of 2019. Two sources of capital costs data from a total of 20,043 heat pumps (15,669 air source and 4,374 ground source) are accessed for this study using the domestic RHI statistics: the total capital cost (£) to install heat pumps and the costs (£ per kW) according to the installation capacities (sizes) of heat pumps. Figure 4.8 outlines the number of domestic air source and ground source heat pump installations and the overall capital costs (£) according to their installation capacities, while Figure 4.9 shows their capital costs (£ per kW) in relation to the installed capacity. In addition, Figure 4.8 also shows the linear trends related to the relationship between installed domestic heat pump capacities and capital costs.

From Figure 4.8, it is clear that among the majority of installed domestic heat pumps (with individual capacity under 20 kW), the overall capital costs increase steadily when the installation capacity of the heat pump increases, while Figure 4.9 shows that the unit costs (£ per kW) decrease when the size of the heat pump increases, an indication of economies of scale. To provide one example, the overall capital cost of an air source heat pump increases from around £7,000 to more than £13,000 when the heat pump installation capacity increases from under 5 kW to over 15 kW, while the capital cost per kW declines rapidly from more than £1,500/kW to less than £900/kW. Similar tendencies are also found in the dataset of the median capital costs of heat pumps installed by December 2018, as is shown in Figure 4.10. Here, while the median capital costs per kW of ground source heat pumps and air source heat pumps reach £1,800/kW and £1,500/kW, respectively, in the group of heat pumps that are smaller than 5 kW, the cost decreases to around £1,100/kW and £500/kW, respectively, when the heat pump installation capacities become larger than 40 kW.

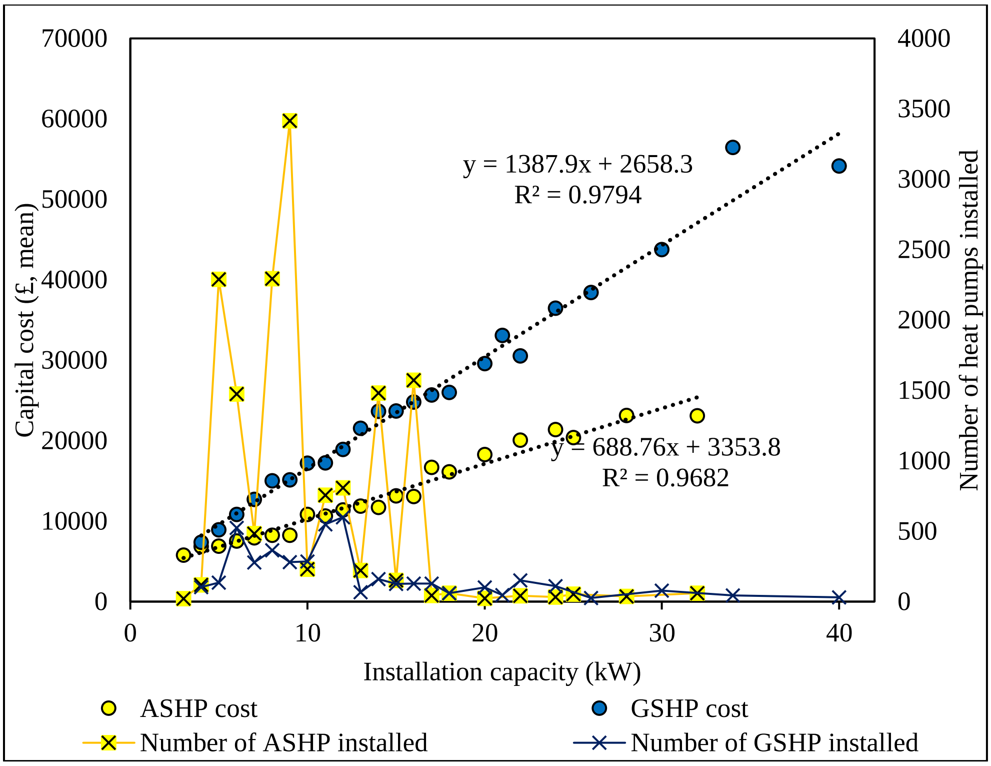

Figure 4.8: The numbers of installations and the average capital costs (£) of domestic air source and ground source heat pumps according to their installation capacities.

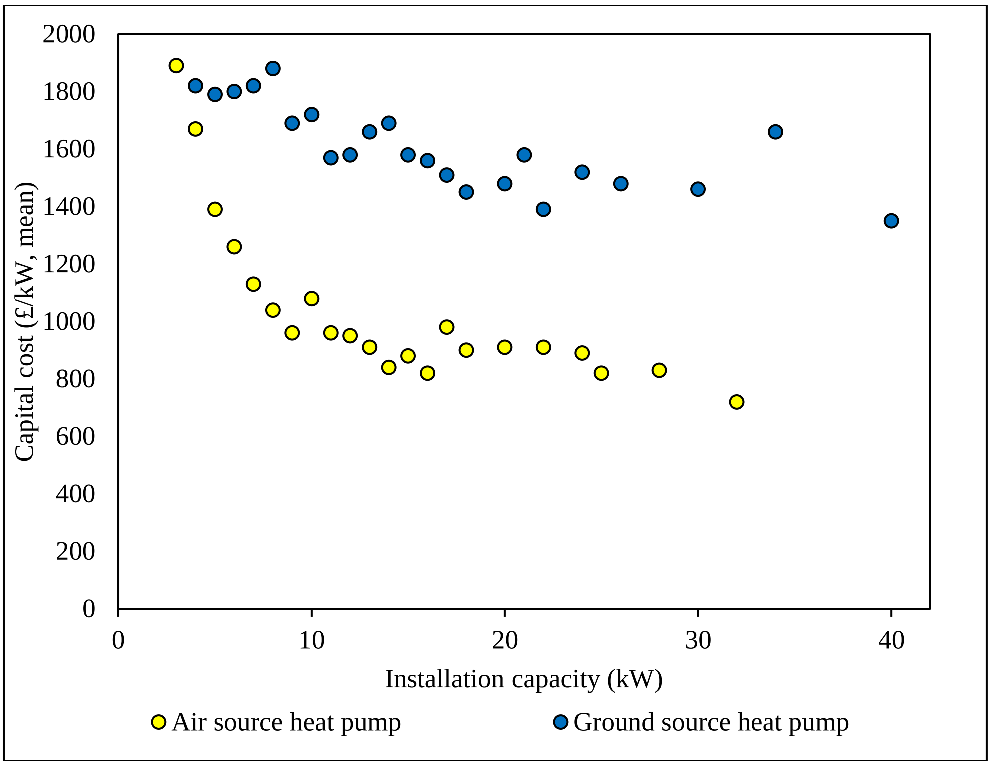

Figure 4.9: The average capital costs (£/kW) of domestic air source and ground heat pumps in relation to their installation capacities.

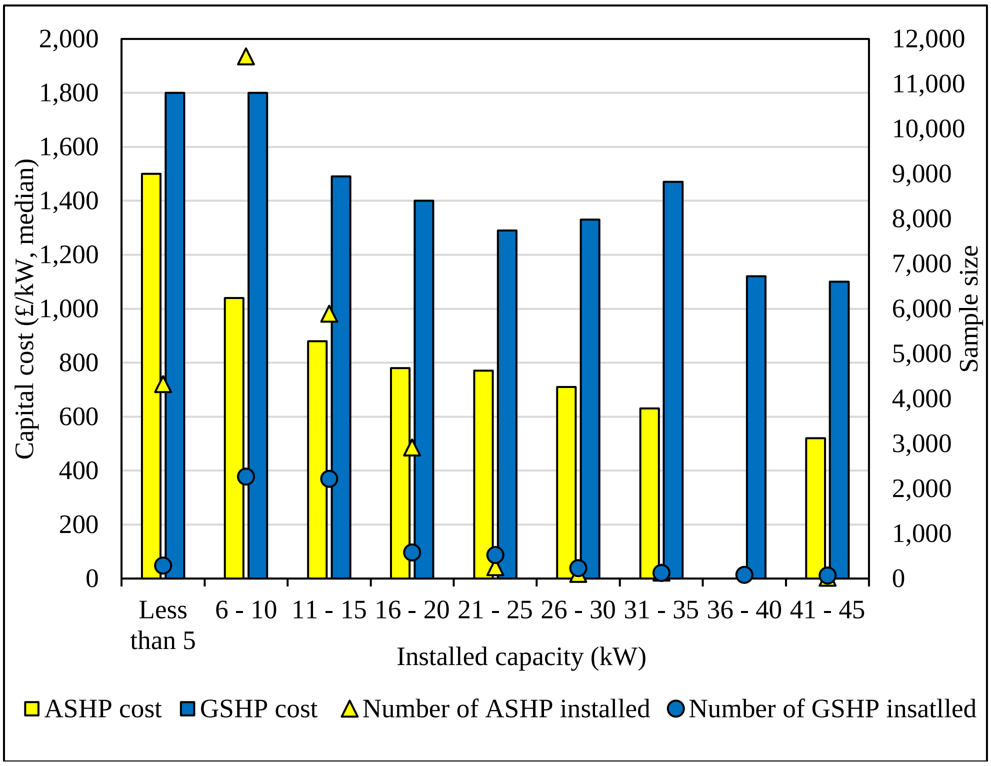

Figure 4.10: The median capital costs (£/kW) of domestic air source and ground source heat pumps according to their installation capacity groups.

4.4.1.2 Operations, efficiencies and gas and electricity costs of individual heating technologies

While the performance of a heat pump can be affected by numerous factors, fundamentally, its efficiency (COP) is substantially affected by the operating temperatures of the heat pump. Consequently, the operational temperature of heat pumps and the temperature of their heat sources become the dominating features that affect the overall technology performance. This study obtained the UK's 2009 average hourly external air temperature profile (Section 3.3.1.3, page 92) to model how the hourly COPs of an air source heat pump change.

It is relatively more challenging to gather monitored hourly underground temperature data to model the hourly COPs of ground source heat pumps. The underground temperature remains relatively more stable than the air temperature, and it can be affected by complex local conditions such as soil composition, moisture and vegetative cover. For modelling purposes, this study uses the 2009 monitored daily soil temperatures at a depth of one metre from a monitoring site in London (Met Office and CEDA, 2019b) and assumes that the underground temperature remains the same over a 24-hour period.

Based on Equation (4.2) and the hourly external air and underground temperatures over a one-year period, the hourly COPs of an air source heat pump and a ground source heat pump are simulated, assuming that the supplying temperature reaches 60 ℃, which is the minimum temperature set by the HSE to avoid the risk of Legionella contamination (Bartram et al., 2007; HSE, 2019). Moreover, the seasonal changes of the COP of a ground source heat pump are comparatively less significant than with an air source heat pump, because the model assumes that the underground temperature varies less seasonally and tends to be higher than the air temperature in the winter. Also, the evaporator of a ground source heat pump does not normally operate below zero Celsius degree because the underground temperature typically stays above zero Celsius degree, and there is no need to defrost the external heat exchanger.

Consequently, the heat pumps' electricity consumption per unit of heat generated is modelled hourly through a whole year. Figure 4.11 shows how the modelled COPs of heat pumps fluctuate. On average, the COPs for an air source heat pump and a ground source heat pump are 3.4 and 3.9, respectively, over a one-year period, while the COP of both heat pumps is lower in the winter due to the higher difference between the operating temperature and heat source temperature. The COPs of an air source heat pump and a ground source heat pump peaked at around 5.0 and 4.5 in summer, while the lowest COPs are less than 2.6 and 3.4 in winter.

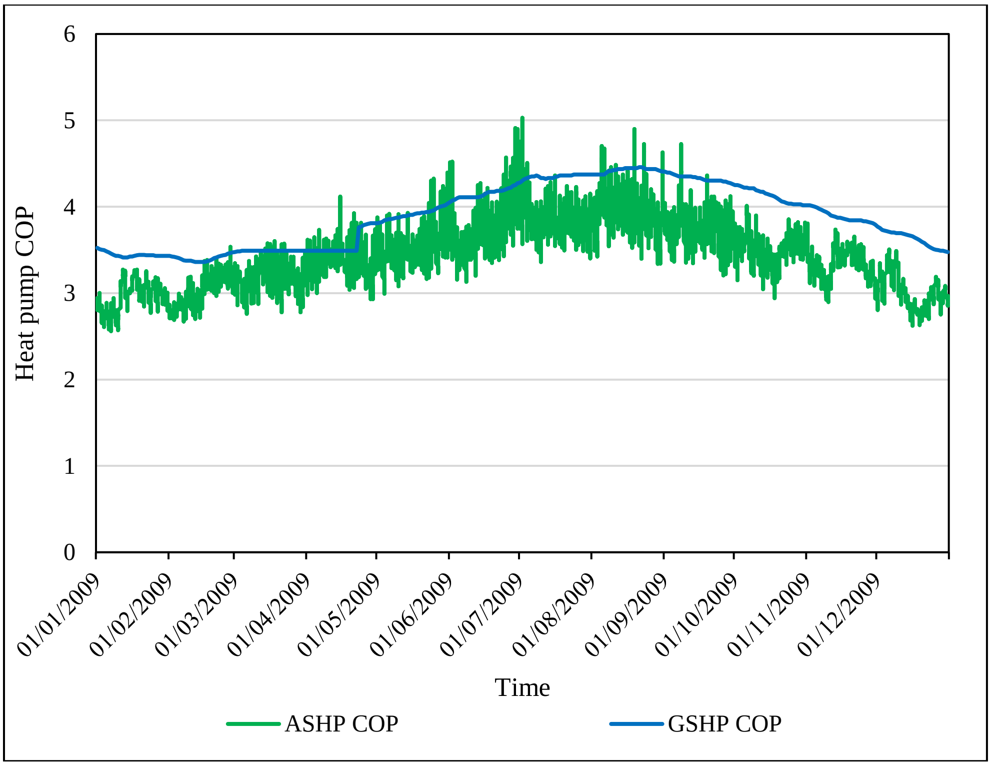

Figure 4.11: Modelled COPs of a domestic air source heat pump and a domestic ground source heat pump over a one-year period.

In terms of gas and electricity costs, it is relatively more straightforward to estimate the fuel consumption of a gas boiler than that of an electric heat pump, because it is assumed that the efficiency of the former remains comparatively more stable than that of the latter in relation to the seasonal weather changes. This model thus assumes that the efficiency of a gas boiler remains constant over a year and that the COP of heat pumps varies, as is illustrated in Figure 4.11. Moreover, Table 4.9 shows the amount of gas and electricity consumed over a one year period by the three heating options in meeting the domestic heat demand based on the average heat consumption per dwelling (14,303 kWh) from the EDRP field trials.

Table 4.9: Annual fuel consumption from three types of heating technologies.

Annual fuel consumption	**Gas boiler**	**ASHP**	**GSHP**
Gas or electricity (kWh)	15892	4495	3916

Two types of hourly load profiles are used to model how individual heat pumps are operated. The first assumes that individual heat pumps are operated as gas boilers based on the gas boiler load profile from the EDRP field trials (Figure 3.30, in Section 3.4.8, page 130). In contrast, the second assumes that individual heat pumps are operated based on the heat pump load profile from the RHPP field trials.

Furthermore, three types of electricity and the annual gas prices from 2018 are incorporated within the model in order to compare the gas and electricity costs over a whole year under different pricing mechanisms, as shown in Figure 4.12. These three electricity price types are as follows: the annual fixed retail electricity price (as well as gas) published by the government (BEIS, 2019d); the hourly spot retail electricity prices from a utility company (Octopus Energy, 2019); and the hourly wholesale price from a power trading market (Nord Pool, 2019).

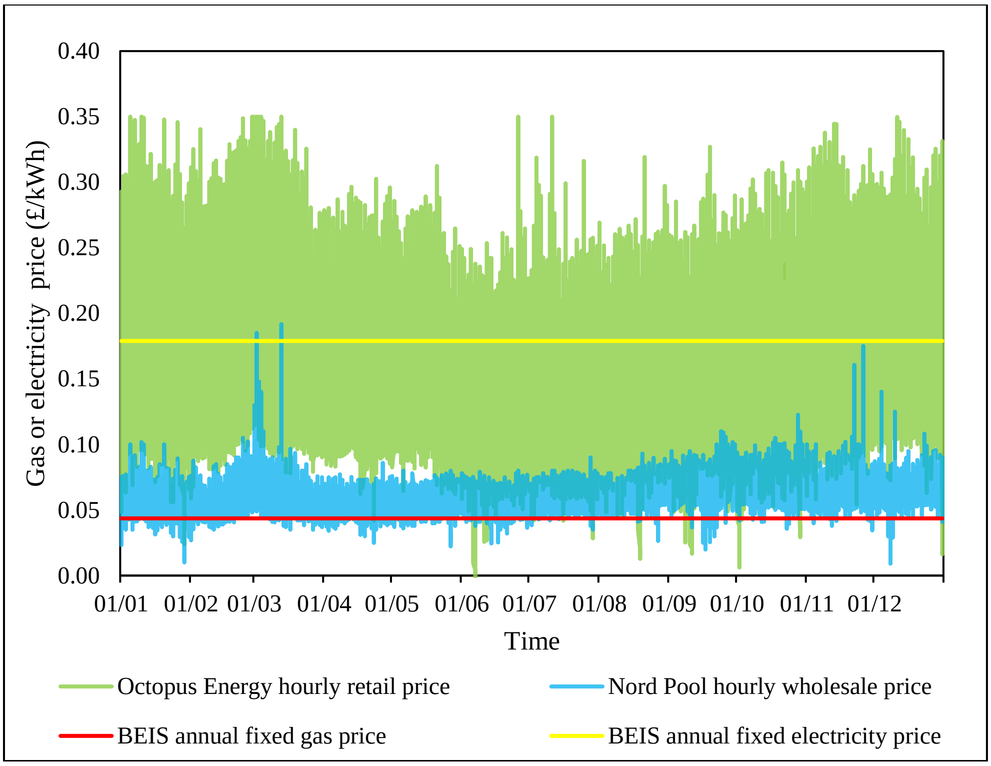

Figure 4.12: Three types of gas and electricity prices for a one-year period.

Based on these three types of electricity price, Figure 4.13 presents a comparison of the overall annual fuel costs of a gas boiler versus those of electric heat pumps in meeting the annual heat demand of one dwelling, under the condition that electric heat pumps are operated the same as gas boilers according to the EDRP load profiles. Meanwhile, Figure 4.14 shows the differences in the annual electricity costs of electric heat pumps based on the hourly retail and wholesale prices, when they are operated in accordance with the RHPP heat pump load profiles versus the EDRP gas boiler load profiles.

As Figure 4.13 indicates, with fixed gas and electricity prices (BEIS, 2019d) over a one-year period, the fuel costs for a gas boiler stand at around £690, while the costs for an air course heat pump and a ground source heat pump are about £740 and £660, respectively. However, the annual electricity costs decrease if the hourly prices (Octopus Energy, 2019) are applied. Here, compared to the annual fixed electricity price, the annual electricity costs for heat pumps drop by over 10% if hourly retail prices are applied, and by around 34%, to around £270 per air source heat pump and £230 per ground source heat pump, if hourly wholesale prices (Nord Pool, 2019) are applied.

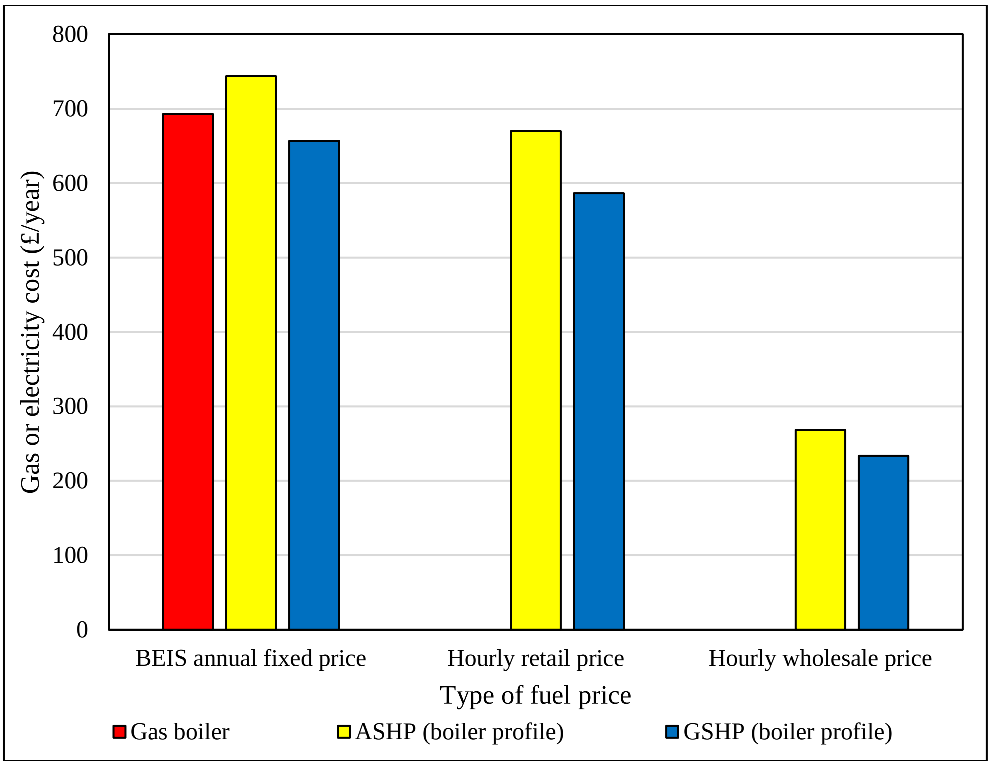

Figure 4.13: Annual gas or electricity costs from three individual heating options based on three types of fuel price (assuming that heat pumps operate like gas boilers).

Furthermore, as demonstrated in Section 3.4.8 (page 128), the EDRP hourly gas boiler load profiles are different from the RHPP hourly heat pump load profiles. Individual heat pumps might operate more continuously with less heat generated during peak hours while hourly electricity prices are higher. Hence, heat pumps operating under the RHPP load profiles and hourly electricity price schemes may take advantage of the low hourly electricity prices outside of the peak hours with decreased overall electricity costs. Consequently, as Figure 4.14 indicates that the electricity costs of heat pumps may decrease by a further 11–14%, to about £250 (air source) and £220 (ground source) per year, if they are operated according to the load profiles from the RHPP field trials. Although wholesale fuel prices are much cheaper than retail fuel prices, it is unlikely that individual customers have access to the wholesale prices in practice.

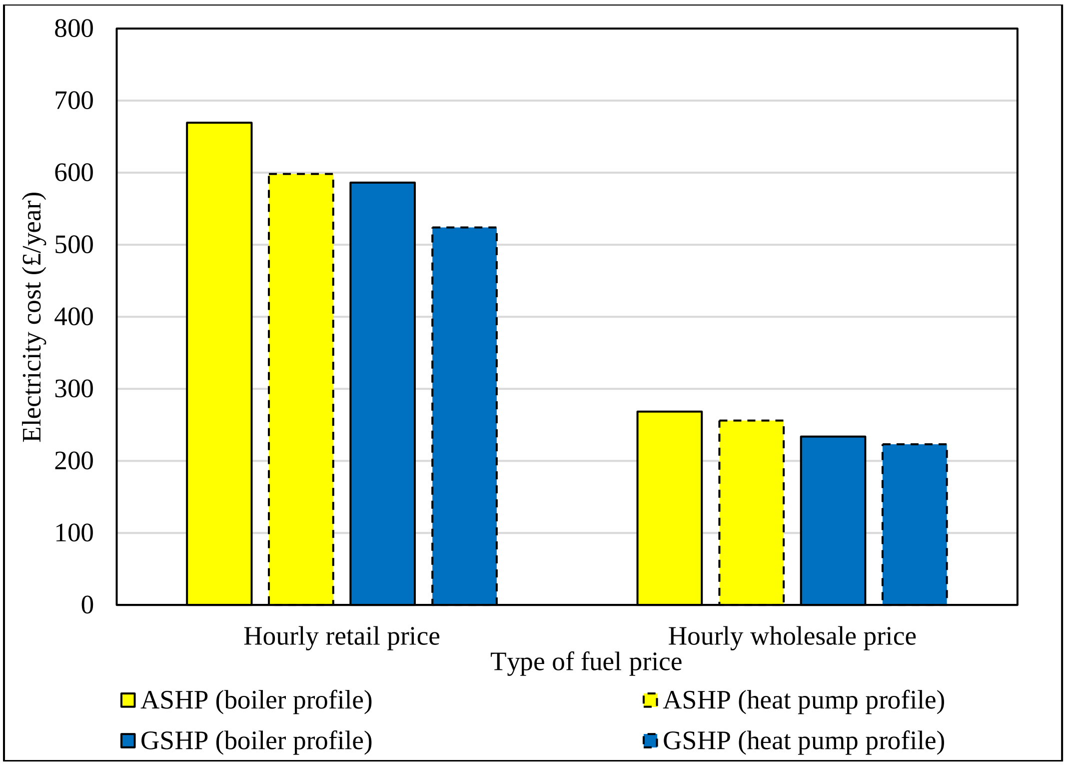

Figure 4.14: Annual electricity costs of individual air source and ground source heat pumps based on two types of load profiles.

4.4.1.3 Levelised cost of heat and carbon emissions for individual heating technologies

The levelised cost of heat (LCOH) model is constructed for different individual heating technologies and district heating networks, meeting the heat demand of various types of British dwellings. With a baseline 3.5% discount rate used throughout the technologies' lifetimes, Figure 4.15 shows the overall LCOH for individual heating technologies in different dwelling types. It is assumed that all the heating measures came into service in 2018, and that a gas boiler has a 15-year technology lifespan, while heat pumps have a 20-year lifespan. This model assumes that all the heat pumps can be installed in different types of dwellings, with the exception that individual ground source heat pumps are not suitable for individual flats due to the lack of underground spaces or suitable heat sources.

Figure 4.15 summarises the overall LCOH for different individual heating technologies based on the estimated heat demand (Section 3.4.2, page 103) from the five typical types of British dwellings. In general, the overall LCOH is lower in dwellings with a higher annual heat demand, while the difference between the LCOH for a gas boiler and those for heat pumps becomes larger when heat demand decreases among the five dwelling types. As expected, a gas boiler is the cheapest way to meet the heat demand in all the individual dwellings, with an overall LCOH of just over £75/MWh in a detached house and just under £95/MWh in a flat. A ground source heat pump is clearly shown to be the most expensive individual technology for meeting heat demand in all the dwelling types, with the LCOH reaching £135/MWh for a terraced house.

Figure 4.15 also indicates that the overall LCOH for a flat is relatively higher than that for other dwelling types due to its low annual heat demand, with the LCOH for an air source heat pump reaching more than £120/MWh. Meanwhile, based on the average heat demand across all the dwellings of the EDRP field trials, the LCOH for a gas boiler is around £83/MWh, which means it is roughly 20% cheaper than an air source heat pump and 35% cheaper than a ground source heat pump.

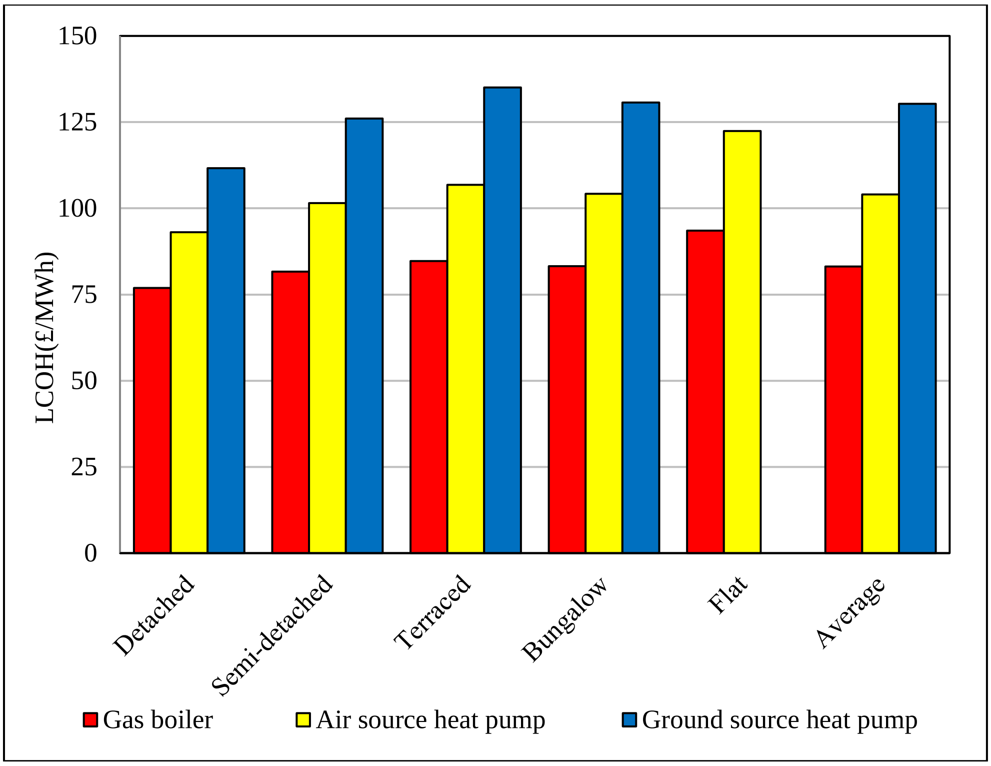

Figure 4.15: The overall LCOH for individual heating technologies in different types of dwelling.

Furthermore, Figure 4.16 reveals additional details about the composition of the overall levelised cost based on different cost elements of each type of heating measure. As the figure clearly shows, capital cost accounts for less than 20% of the overall LCOH for a gas boiler, while it accounts for over 40% and 60% of the LCOH for an air source heat pump and a ground source heat pump, respectively. In fact, fuel (gas or electricity) cost is the largest component of the LCOH for both a gas boiler (63%) and an air source heat pump (53%), while the figure drops to less than 37% with the ground source heat pump which has a higher overall COP.

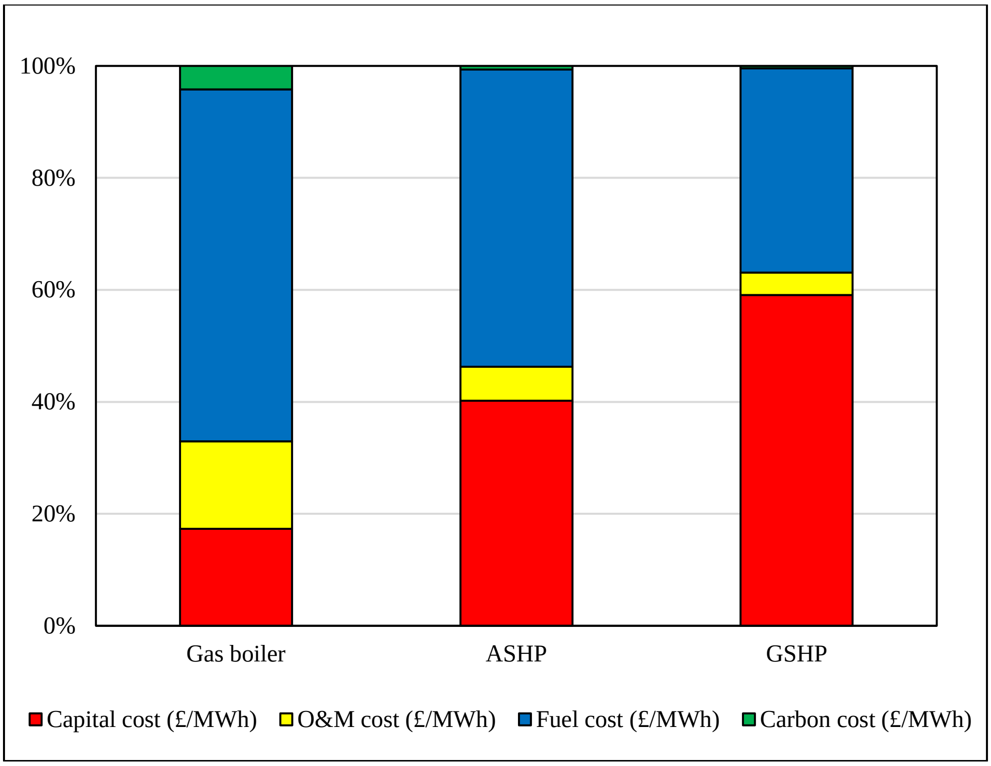

Figure 4.16: The components of the overall LCOH for individual heating technologies.

Furthermore, across the three individual heating technologies, the proportion of operational cost decreases from more than 15% of the LCOH for a gas boiler, to 6% and 4% of the overall LCOH for air source heat pumps and ground source heat pumps, respectively. In addition, carbon cost only accounts for a small percentage of the LCOH for all three heating measures (4% for a gas boiler and less than 1% for the heat pumps) due to the low projected carbon prices and the projected intensive future reductions in the carbon intensity of the electricity grid.

However, the projected carbon prices by BEIS (2019e) do not reflect the actual costs to remove atmospheric carbon emissions. The real cost of carbon is likely to be much higher than the prices projected by BEIS to evaluate energy investments. Also, in light of the recently introduced targets to achieve net-zero emission by 2050, carbon prices are likely to be raised by the government to discourage fossil fuels consumption.

While heat pumps are more expensive than gas boilers, in terms of both capital costs and the LOCH, for supplying heat to all individual dwellings, they can significantly reduce the carbon emissions from domestic heating, on the condition that the carbon intensity of the electricity grid in the UK continues to decrease as per future projections (BEIS, 2019d). In terms of the total carbon emissions associated with the three types of individual heating technologies over their respective lifetimes, the model calculates that a gas boiler may emit around 44 tonnes of carbon dioxide over a 15-year period, while heat pumps may emit between ten tonnes (ground source) and more than 12 tonnes (air source) of carbon emissions in a 20-year period based on the average annual heat demand.

Based on the carbon content of natural gas and the projected future carbon intensity of electricity in the UK, Figure 4.17 shows the average annual carbon dioxide emissions from the three individual heating measures over their respective lifetimes in the five main types of British dwelling. On average, a gas boiler may emit approximately three tonnes of carbon dioxide a year. In contrast, a heat pump could reduce a household's carbon emissions by up to 82% per year in meeting the heat demand, with roughly 0.5 and 0.6 tonnes of annual carbon emissions from a ground source heat pump and an air source heat pump, respectively, thanks to high technology efficiencies and projected low-carbon electricity.

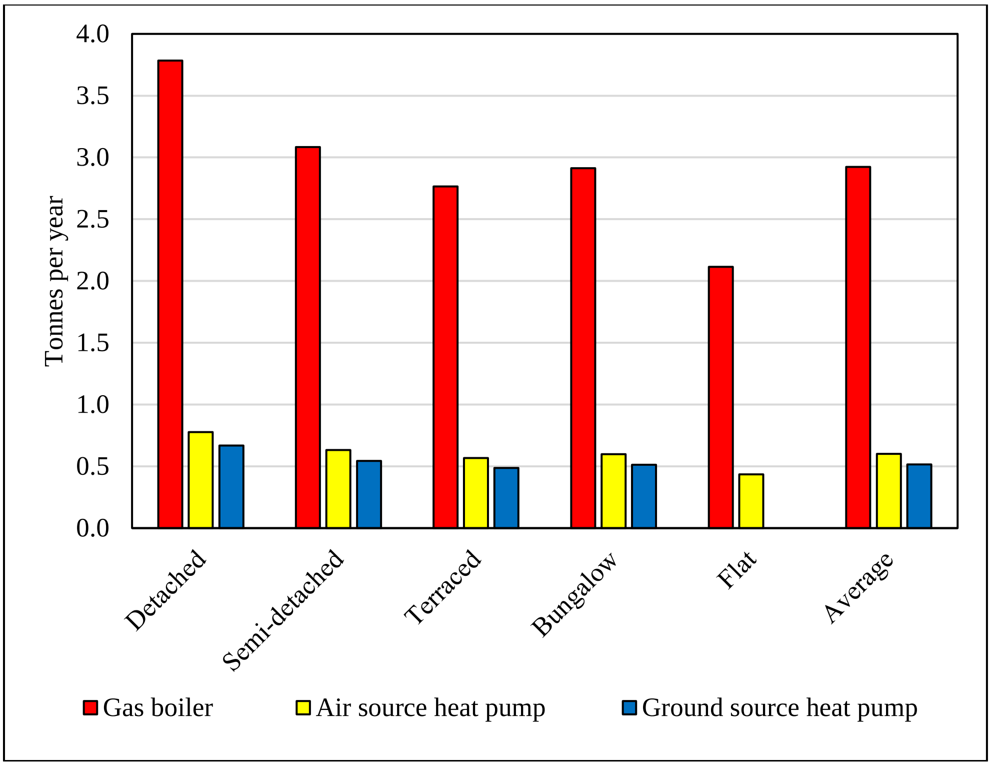

Figure 4.17: Average annual carbon emissions of different types of heating measures in various dwelling types.

4.4.2 Three topological configurations to utilise electric heat pumps in district heating networks

Besides installing heat pumps at individual dwellings, heat pumps can be integrated into district heating networks through three topological configurations based on the sizes of heat pumps and operating strategies of district heating networks as previously illustrated in Figure 4.1. Integrating heat pumps into district heating networks provides an opportunity to remove incumbent heating appliances at the individual level or utilise heat sources which are difficult to get accessed by individual households. The following subsections quantify the aggregated heat demand at district scales and then evaluate technical, economic and environmental comparative advantages among the three topological configurations to utilise heat pumps in district heating networks on different scales.

4.4.2.1 Aggregated heat consumption and peak hourly demand of district heating networks

Chapter 3 of this study quantified the aggregated annual heat consumption from dwellings according to the five defined district heating scales, as well as the potential hourly 'after diversity peak demand', which may occur in the networks based on the demand diversity analysis under extremely cold weather conditions. Table 4.10 provides a summary of the annual heat demand for the five scales of district heating networks, and the ADMD used to determine the sizes of large scale heat pumps installed in district heating networks, the capacities of the technological elements in a district heating systems (e.g. substations), and their associated capital and operational costs.

Because the current existing single largest heat pump units may meet the peak demand by up to 35MW (EHPA, 2018b), the model assumes that multiple large scale heat pumps (a group of connected heat pumps) are installed, in order to ensure the security of heat supply and that the peak heat demand is met for district heating networks with a large number of dwellings. For example, as Table 4.10 indicates, a single large scale heat pump with an installed capacity of 753 kW is able to meet the hourly peak demand of a small district heating network. In contrast, a group of large scale heat pumps with a combined capacity of 73.6 MW will be needed for a district heating network that connects over 10,000 dwellings.

Table 4.10: Annual and peak hourly heat demand of district heating networks on five scales.

District heating scale	Number of dwellings assumed in one network	Hourly ADMD (MW) of the network	Annual demand (without transmission heat loss, MWh)
Small heat networks	100	0.75	1430
Medium heat networks	500	3.68	7152
Large heat networks	1500	11.04	21455
Single developments	2500	18.40	35758
Medium multi-developments	10000	73.60	143030

4.4.2.2 Technical and environmental trade-offs among different heat pumps and district heating topological configurations

4.4.2.2.1 District heating network operational temperatures and technology performance

Operational temperature is one of the fundamental factors that differentiate technical performance and the economics of the three heat pump and district heating topological configurations in this study. Indeed, the operational temperatures of district heating systems may influence the overall performance of the district heating network as it can directly affect the efficiency (COP) of heat pumps, as well as the amount of heat loss from the transmission and distribution systems of networks. Heat loss from different district heating network topological configurations may change, depending on the operational temperatures, sizes and lengths of district heating pipes in the network. Hence, they have an impact on overall electricity consumption and carbon emissions, and they consequently influence costs to construct and operate district heating schemes. Additionally, a low operational temperature may allow a heat network to adopt flexible plastic pipes instead of pre-insulated steel pipes, which may lead to cost reductions.

For example, assuming that the temperature of the heat source is 10 ℃ when based on Equations (4.1) and (4.2), the theoretical maximum COP (COP_{carnot}) of a heat pump may drop from over 8.0 to 5.7 and 4.5, respectively, when the delivered temperature correspondingly increases from 50 ℃ to 70 ℃ and 90 ℃, which is shown in Figure 4.18. Moreover, Figure 4.19 shows linear heat loss increases from district heating pipe, DN300 (0.156 m of inner pipe radius), when the distribution temperature changes from 20 ℃ to 90 ℃, and when assuming that the external ambient temperature is 10 ℃.

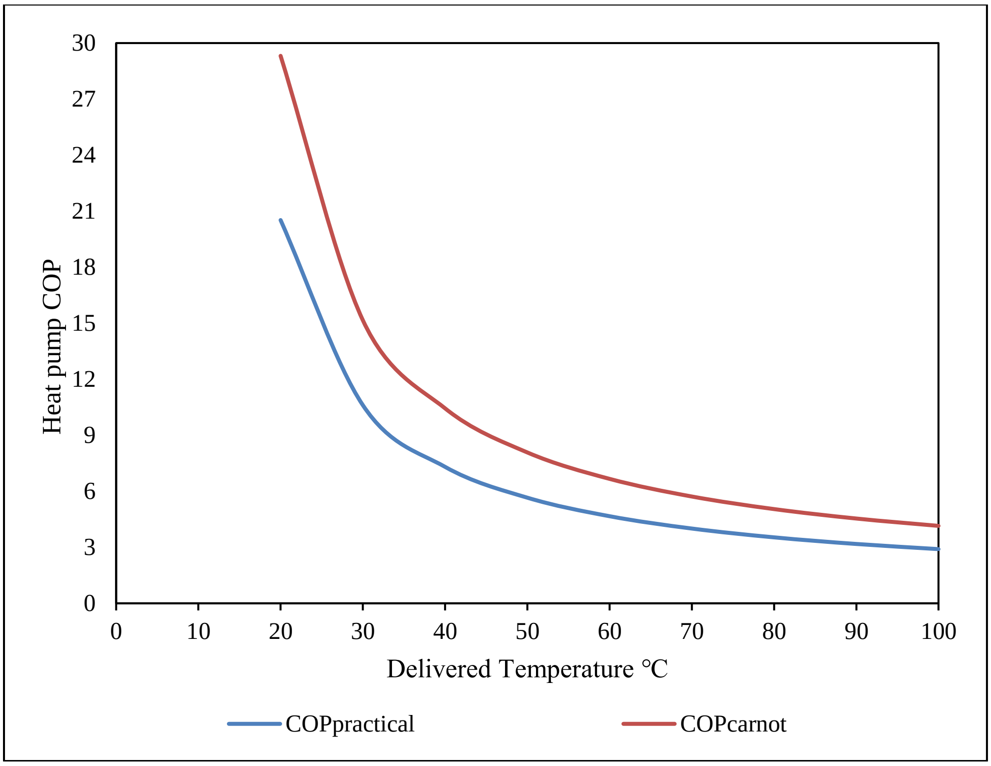

Figure 4.18: Theoretical maximum versus practical COP of a heat pump according to different delivered temperatures, assuming η=0.7 for COP practical (Gasser et al., 2017).

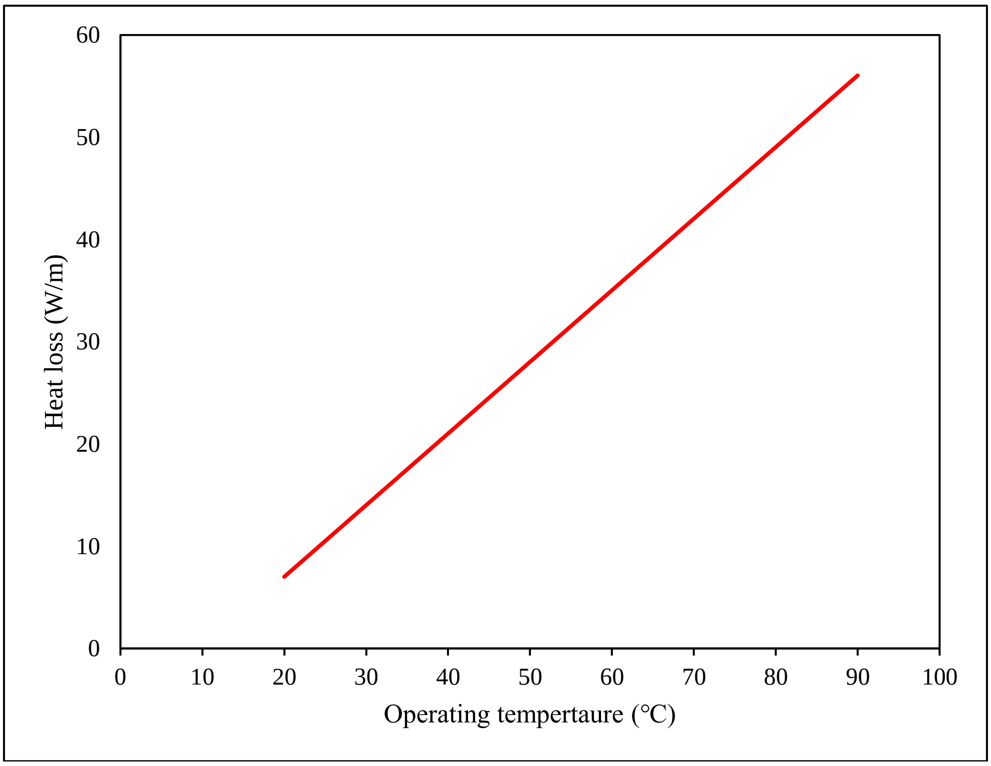

Figure 4.19: Heat loss changes from the DN300 district heating pipe according to various operating temperatures.

To improve the overall performance of the district heating system, reducing the temperature difference between heat sources and delivered heat is an effective way of improving the efficiency (COP) of heat pumps, while also reducing the network heat loss from distribution and transmission systems, such as pipes. However, in practice, it is common for district heating networks (mostly 3GDH) in the UK to operate with supply temperatures of over 80 °C (GLA, 2014), which requires higher levels of insulation in order to reduce transmission heat loss and maintain the required temperature at the delivery dwellings. In turn, this will lead to higher construction and operational costs with regards to district heating networks.

Another critical element that could affect the operation and cost of a district heating network relates to the piping used therein. The price of piping is itself a major component of the cost profile of a district heating network. Furthermore, the operational and physical characteristics of district heating pipes can determine the amount of heat loss and pumping energy consumed during the transmission and distribution processes. These characteristics contribute to the overall heat generation and fuel consumption, as well as the overall efficiency and costs of a district heating system.

When designing the network, optimisation in terms of size, insulation, price, and the cost of pumping is desirable. The thickness of the pipe insulation should be determined by the trade-off between the cost of insulation and the savings made by preventing heat loss. While thicker pipe insulation can reduce heat loss, it can also contribute to higher costs. In practice, pre-insulated bonded pipes are manufactured according to EN standardised dimensions (BS EN13941, 2019), with the pipes' external diameter ranging between 110mm and 1400mm (DN15 to DN1100). District heating network developers select a set of suitable pipes according to the network's characteristics such as designed capacity, transport distance, building and transport layouts and costs.

According to the physical and technical properties and cost data from 14 types of district heating pipes (DN15 to DN300) obtained by this study, Figure 4.20 illustrates the amount of heat loss (W/m/K) from differently sized pipes. It has been calculated based on Equation (4.5), assuming that all pipes are manufactured with the same casting and insulation materials. It is clear that the heat loss from pipes increases when the size of the pipe does too, which is due to the increased surface area. Moreover, according to the cost data of different pipes obtained from DEA and Ramboll (2018), the capital cost (including designing and installation) of pipes per metre increases fourfold when the inner radius of pipes increases from 0.009 m (DN15) to 0.156 m (DN300).

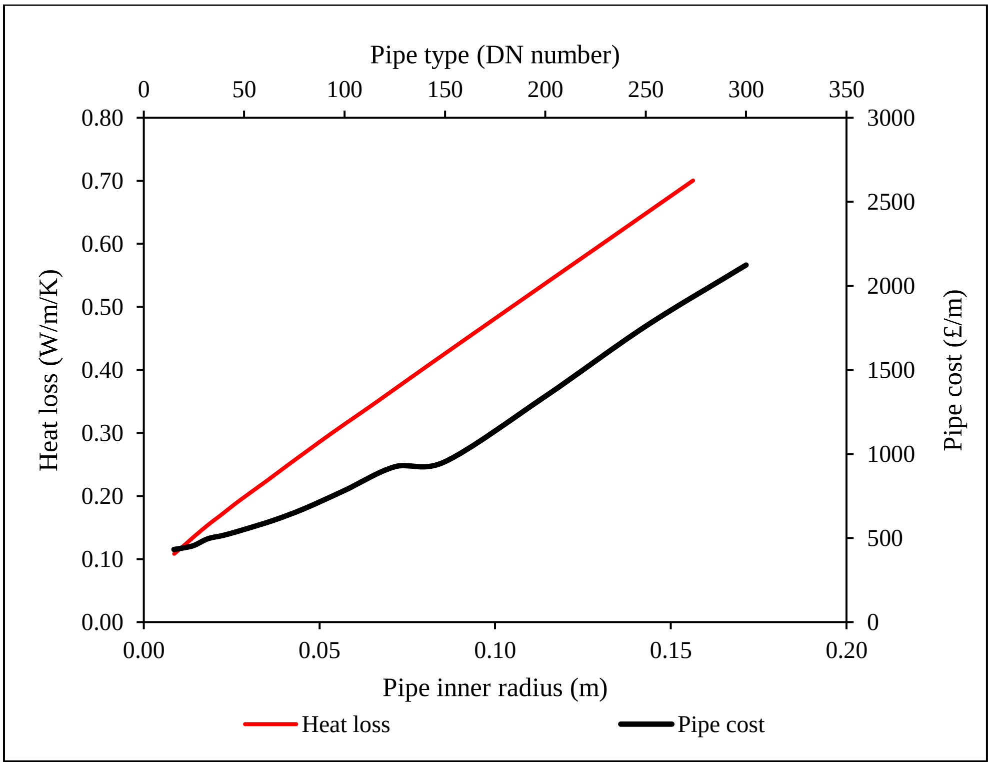

Figure 4.20: Heat loss and pipe cost from 14 sizes of district heating pipes.

In a district heating network that utilises electric heat pumps to generate heat, electricity is also consumed to pump water along the transmission and distribution systems. Although heat loss goes down when the pipe size decreases, it is not always the best option to use the smallest suitable pipes in district heating networks. This is because the energy consumed to pump water across the pipes will increase, which would lead to additional electricity consumption. Depending on how district heating suppliers value electricity, trade-offs exist between the electricity consumed to generate heat and the electricity consumed to pump water within the district heating system.

Based on the technical characteristics of district heating pipes obtained from industrial catalogues (Brugg, 2003; DEA and Ramboll, 2018), and while assuming that all of the piping has the same operating conditions (80 °C hot water temperature, 10 °C external ambient temperature and 0.007mm pipe surface roughness), this study modelled and quantified heat loss versus pumping energy for different sizes of district heating pipe via Equations (4.5) and (4.6).

Figure 4.21 illustrates the trade-offs between pumping energy and heat loss among different pipes. When the size of the district heating pipes increases, heat loss rises as well; meanwhile, the pumping energy required decreases. As shown in Figure 4.22, in terms of the overall loss (W/m) for a particular size of pipe under a specified set of operational conditions, when heat loss and pumping energy are combined, a minimum overall loss may occur.

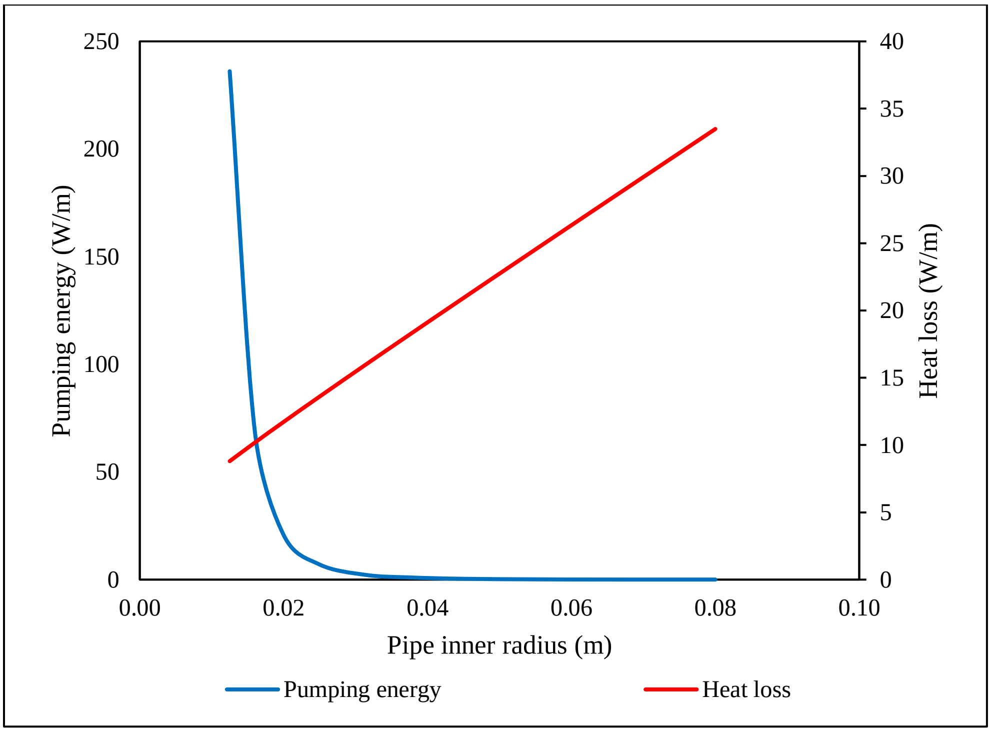

Figure 4.21: Heat loss, pumping energy and total loss with respect to the sizes of district heating pipes.

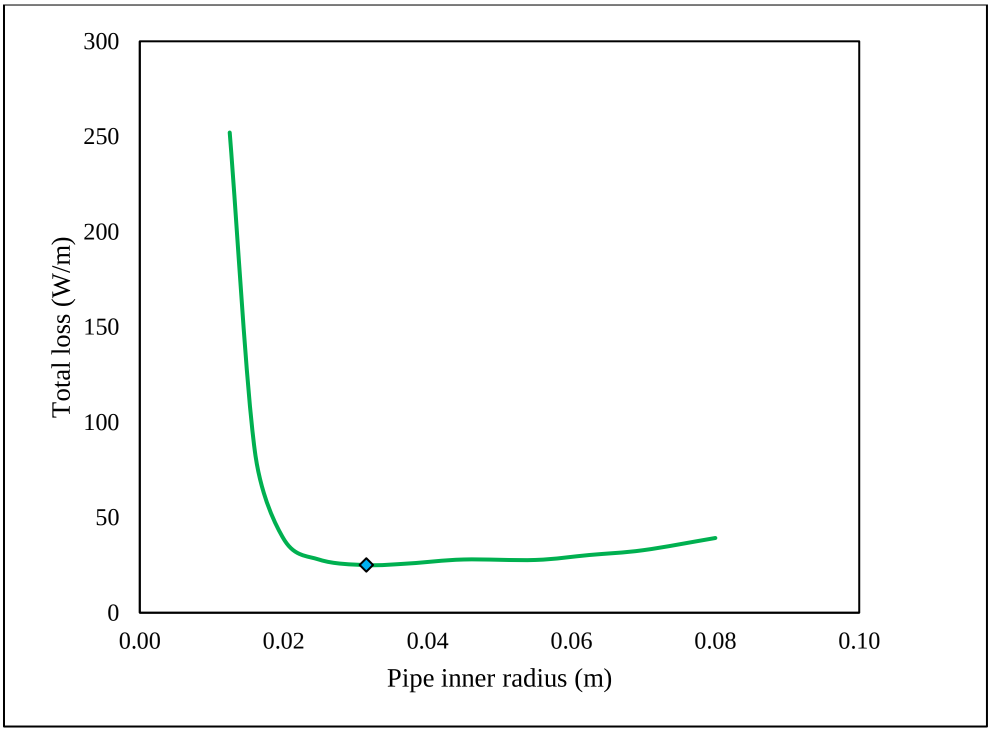

Figure 4.22: Heat loss, pumping energy and total loss with respect to the sizes of district heating pipes.

Existing literature suggests that the pumping energy needed is an order of magnitude smaller than heat loss, which is around 0.5% of the heat delivered (Frederiksen and Werner, 2013). Many previous modelling studies simply assumed that a small proportion of network energy was used for pumping. For instance, AECOM and DECC (2015) used the phrase 'network parasitic electricity consumption' to describe energy consumption, including pumping energy, which they found to account for 1.9% of heat demand on average. Nevertheless, the amount of pumping energy is comparatively larger in bigger district heating networks because the distance between supply and demand tends to be greater, as does the pressure drop.

In relation to this, district heating systems tend to be oversized in order to ensure supply security, and oversized district heating pipes may be associated with additional heat loss and reduced pumping energy. Nonetheless, just as Figure 4.21 and Figure 4.22 demonstrate, undersizing district pipes may significantly increase the overall energy loss due to the additional pumping energy needed for network operation. Additional energy loss increases much more when pipe size decreases than when it increases;

hence, the negative impact of undersizing is worse than oversizing for the district heating pipes investigated here. Furthermore, the penalty for incorrect sizing is asymmetric, because more electricity for pumping is needed when pipes are undersized, whereas more heat is lost when pipes are oversized. When heat pumps are utilised in district heating networks, the trade-off between using electricity for pumping and generating additional heat to compensate for distribution heat loss should be evaluated, when selecting district heating pipes, because heat pumps transfer more heat than the electricity they consume depending on their COPs.

This study found that the pumping energy used for large pipes is dramatically lower than small pipes, with the model only considering the energy needed to move water along the pipes. In reality, pumping energy is also required to move water along other parts of the district heating system, such as control valves or exchangers. Although pumping energy appears to be an order of magnitude lower than heat loss from large pipes in district heating networks, it is contentious that pumping energy should not be treated simply as a loss. The mechanical energy is converted into heat due to friction, hence the energy is not actually lost. In addition, pumping energy in networks with low temperatures tends to be relatively larger than with high temperature networks because of the denser water.

Furthermore, the trade-offs between operational temperatures, flow rate, heat loss and pumping energy become more significant when designing future low temperature district heating networks. When the supply temperature decreases, the flow rate needs to increase in order to supply the same amount of heat. On the other hand, if the supply temperature does not change, but the flow and return temperature difference (delta T) increases, (i.e. there is a lower return temperature and more heat is delivered), this means that lower flow rates are needed and consequently less pumping energy as well; all the while, there will be less heat loss due to the lower return temperature. Furthermore, a very low operating temperature may provide the opportunity to utilise plastic pipes, which could reduce capital costs.

4.4.2.2.2 Heat loss, overall electricity consumption and carbon emissions from different heat pumps and district heating topological configurations

The model developed in this study assumes that there are two sets of operating temperatures for district heating networks. This is according to how heat pumps are integrated into the networks (Topologies 2, 3 and 4). For Topology 2 (T2), the model assumes large centralised heat pumps are utilised to supply heat for a high temperature network (80 ℃ flow and 60 ℃ return), which is similar to a conventional district heating network where heat is initially generated centrally, and it is then distributed to individual dwellings through hot water pipes.

Meanwhile, Topology 3 and 4 (T3 and T4) assume that centralised heat sources (either through a free source or generated by large scale heat pumps) are used to supply heat to low temperature networks (30 ℃ flow and ambient return), and additional heat is generated in a decentralised manner at individual household level by individual booster heat pumps to satisfy heat demand. Consequently, different topological configurations to utilise heat pumps may cause changing levels of heat loss through heat transmission and distribution, as well as heat pump performance (mainly COPs). These lead to the variances in overall heat generation, electricity consumption and carbon emissions among different topological configurations when operating heat pumps and district heating systems.

This study assumes that two types of pre-insulated district heating pipes are installed for different district heating topological configurations: transport pipes and service pipes. Transport pipes are used to transfer hot water from energy centres to the group of dwellings in the heat network, and service pipes are used to deliver heat from transport pipes to individual dwellings. These two types of district heating pipes are selected from the DEA and Ramboll (2018) pre-insulated pipes database (Table 4.8, page 191), according to their designed peak capacities and aggregated peak demand for different scales of district heating networks.

The district heating network's aggregated peak demand is calculated based on the ADMD per dwelling and the total number of dwellings connected in the network (as previously quantified in Table 4.10). In order to meet pre-diversified individual peak demand, DN25 pipes (with a peak capacity of 35 kW) are used for all district heating scales as service pipes that connect individual dwellings to the main transport networks.

As previously indicated in Section 4.3.2 (page 173), a district heating network's layout and the length of transport pipes can vary significantly depending on a combination of local conditions. This study applies the average length (13.3 m) of internal service pipes indicated by AECOM and DECC (2015). For transport pipes, DN100, DN150, DN200, DN250, and DN300 are used in different scales of district heating networks based on the ADMD. This study assumes that in a small district heating network with 100 dwellings, only one type of transport pipe is used as the network's transport pipes, and additional tiers of transport pipes are utilised when the scale of the district heating network expands.

For modelling purposes, this model assumes that one extra tier of transport pipe is utilised when the district heating network expands from a smaller to a larger scale, and each additional tier of transport pipe contributes to 20% of the total length of the network's transport pipes. For example, in a medium scale network with 500 dwellings, DN150 pipes contribute to 20% of the network's transport pipes and DN100 pipes are used for the remaining 80%. For a large scale network with 1,500 dwellings, DN200 and DN150 pipes contribute to 20% each of the total transport pipes, and DN100 pipes are used for the remaining 60%. For the largest district heating scale with 10,000 dwellings, each of the five tiers of transport pipes contributes to 20% of the total length of the network's transport pipes. Furthermore, the technical features (data from the DEA and Ramboll (2018)) of these pipes are used to calculate network pipe heat loss (based on Equation (4.5)), as shown in Table 4.11 below. Table 4.12 shows the lengths and types of transport and service pipes assumed in the model.

Table 4.11: District heating service and transport pipes used in different scales of networks.

Pipe (DN)*	Outer diameter (mm)*	Inner diameter (mm)*	Heat loss (W/m/K)**	Designed peak capacity (kW)*
DN25	33.7	29.1	0.137	35
DN100	114.3	107.1	0.300	1129
DN150	168.3	160.3	0.404	3262
DN200	219.1	210.1	0.501	6603
DN250	273.0	263.0	0.604	11912
DN300	323.9	312.7	0.701	18764

*Data from the DEA and Ramboll (2018).
**Heat loss calculated based on Equation (4.5).

Table 4.12: Lengths of transport and service pipes assumed for five scales of district heating networks.

District heating scale	Number of dwellings	The total length of transport pipes (m)	Type of transport pipes used	The total length of service pipes, DN25 (m)
Small heat networks	100	500	DN100	1330
Medium heat networks	500	1622	DN100, DN150	6650
Large heat networks	1500	3180	DN100, DN150, DN200	19950
Single developments	2500	4830	DN100, DN150, DN200, DN250	33250
Medium multi-developments	10000	15200	DN100, DN150, DN200, DN250, DN300	133000

Figure 4.23 and Figure 4.24 indicate distribution heat loss and pumping energy from transport and services pipes of different district heating networks when they are operating with two different temperature levels. These two figures also compare the relative heat loss from district heating pipes as a percentage of the overall annual heat generation on the five defined district heating scales. As expected, lowering operational temperatures can significantly reduce rates of heat loss from district heating networks.

When taking a large district heating network (1,500 dwellings) with high operational temperatures as an example, as in Topology 2, the total heat loss from district heating pipes accounts for more than 15% of the total annual heat generation (Figure 4.23), whereas the value is less than 3% for low temperature district heating networks (Figure 4.24, Topology 3 and 4), assuming that both topological configurations have the same type of district heating transport and service pipes under the same scale category. Additionally, this study assumes the same pumping energy under different network operating temperatures for the same type of district heating pipes, due to data availability.

Moreover, these two figures also indicate total heat loss and heat loss as a percentage of the overall heat generation. The accumulated length of district heating pipes becomes longer when the size of the district heating network increases, which causes total heat loss and pumping energy (in terms of total kWh) to increase. On the other hand, heat loss as a percentage of the overall heat generation decreases under the same operating condition when the scale of the district heating network changes from the smallest heat network to the largest heat network. When the scale of district heating networks expands, longer and larger pipes are used. This leads to higher distribution heat loss; nevertheless, the total heat demand of the network increases at a larger scale than heat loss. Consequently, heat loss from transport pipes as a percentage of the total heat generation could decrease when the network becomes very large.

This is exemplified with high operational temperatures (Figure 4.23, Topology 2) when more than 2,700 kWh of heat per dwelling per year is lost from district heating pipes in a small network (100 dwellings), which accounts for approximately 16% of the overall heat generation. Both total heat loss and heat loss as percentages of total heat generation increase when the scale of the district heating expands from 100 dwellings to 500 dwellings. On the other hand, heat loss per dwelling drops by around 10% to 2,470 kWh per year for a medium multi-development scale district heating network, where the number of dwellings connected to a single network increases a hundredfold from 100 to 10,000.

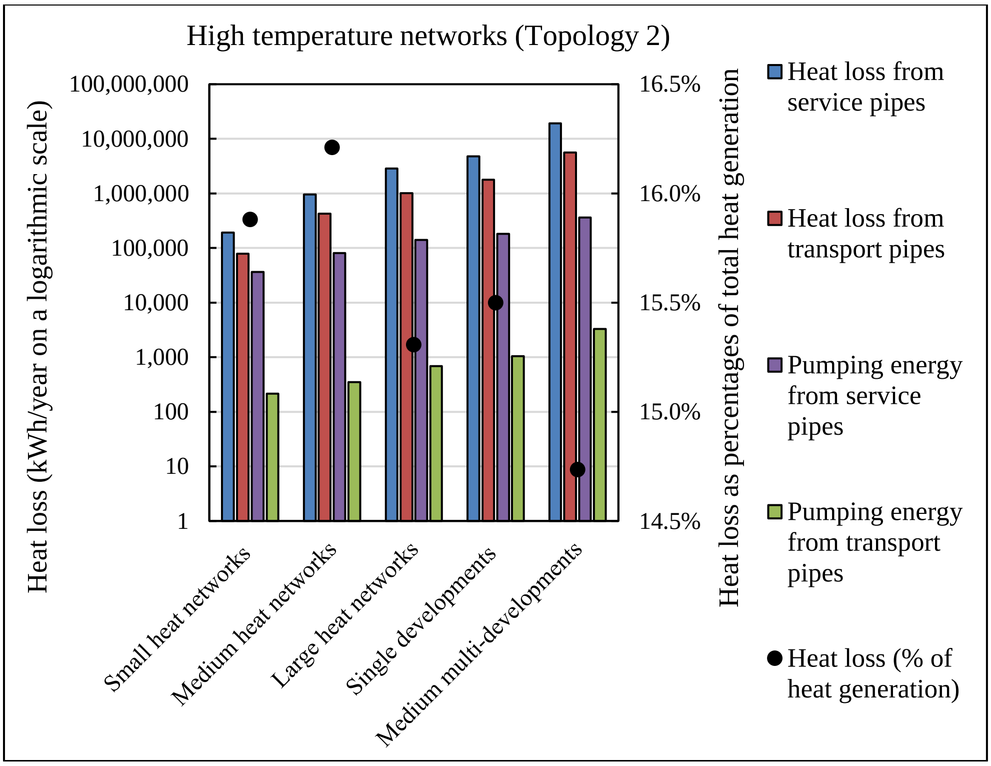

Figure 4.23: Pipe heat loss, pumping energy, and heat loss as a percentage of total heat generation in high temperature networks across five district heating scales.

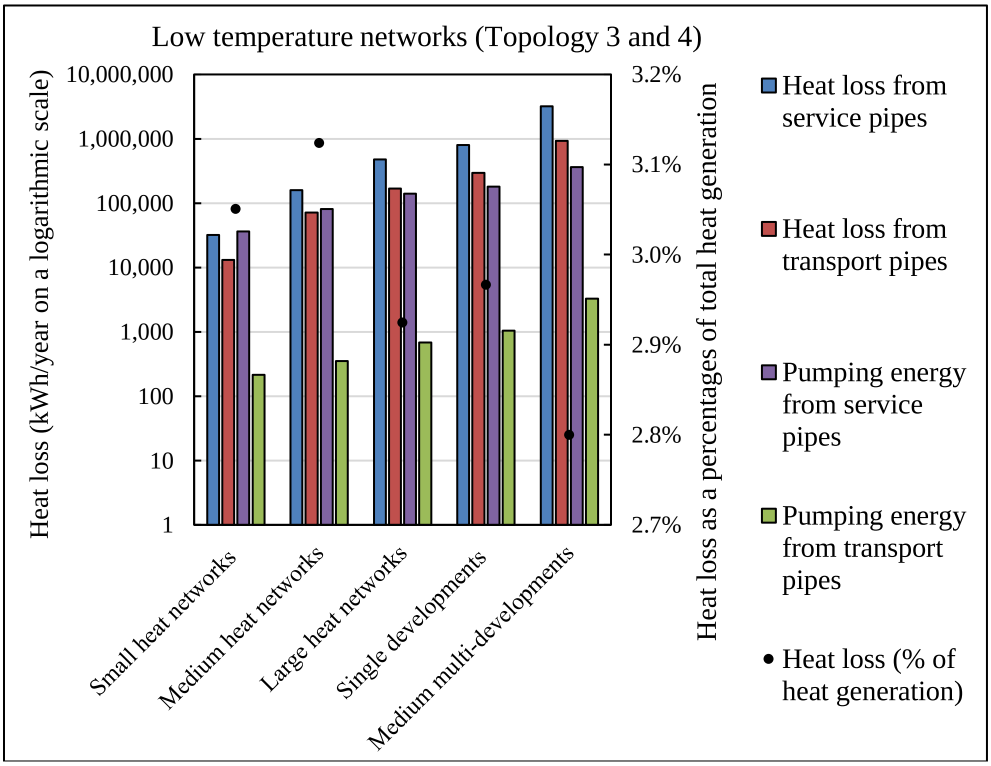

Figure 4.24: Pipe heat loss, pumping energy, and heat loss as a percentage of total heat generation in low temperature networks across five district heating scales.

As previously illustrated in Figure 4.11 (in Section 4.4.1.2, page 197) and Equations (4.1) and (4.2) (in Section 4.3.2), the modelled COPs of heat pumps are dependent on delivered temperatures, heat source temperatures, and assumed system efficiency factors (η). Table 4.13 shows the average annual COPs of heat pumps when they are utilised in different topological configurations under different district heating network operating temperatures. After quantifying heat loss and pumping energy for different heat pumps and district heating topological configurations, the overall heat generation and total electricity consumption are calculated for different topological configurations to utilise heat pumps.

Table 4.13: The COPs of heat pumps when utilised in different topological configurations and district heating operating temperatures.

	Individual ASHP	**Individual GSHP**	**Large heat pumps in high temperature network**	**Small booster heat pumps**	**Large heat pumps in low temperature network**
Assumed efficiency factors (η)*	0.50	0.55	0.70	0.50	0.70
Average annual COP	3.44	3.90	3.68	5.55	10.61

*Data based on Meggers et al. (2010), Wyssen et al. (2010), and Gasser et al. (2017).

Figure 4.25 displays the annual electricity consumption per dwelling from three district heating network topological configurations in comparison with an individual air source heat pump and a ground source heat pump, assuming that all district heating networks are large networks with 1,500 dwellings. Results, which range from around 3,000 kWh to more than 5,000 kWh, show that the average amount of electricity consumed to meet heat demand per dwelling in a year differs considerably depending on the different topological configurations to utilise heat pumps and district heating.

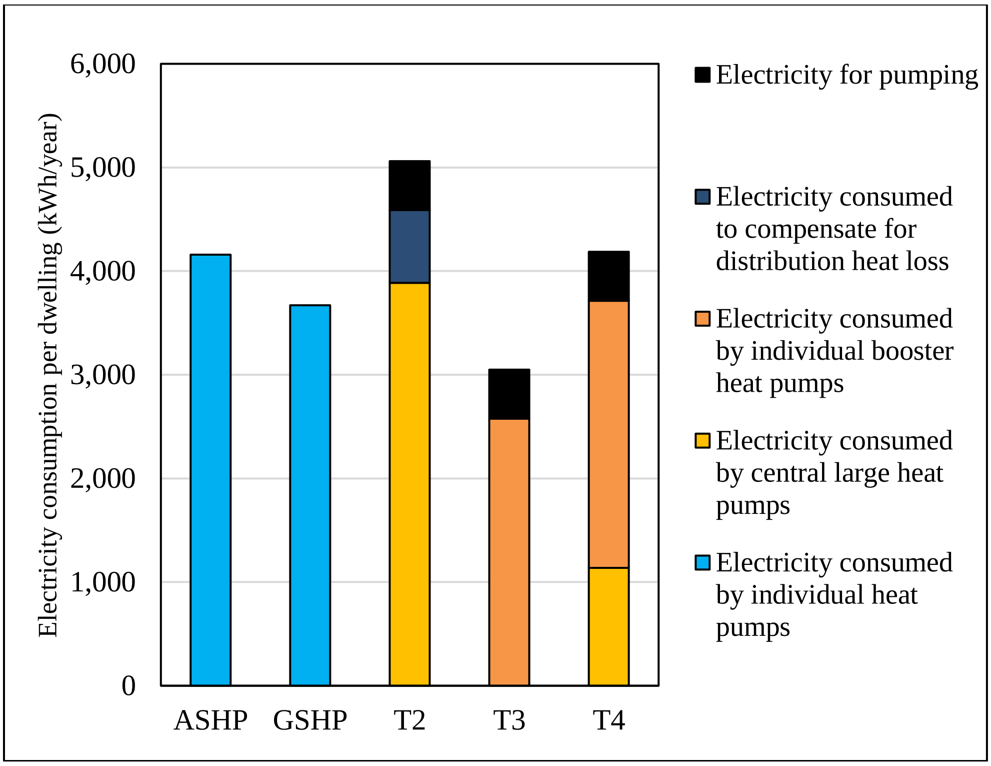

Figure 4.25: Annual electricity consumption per dwelling from each of the four topological configurations to utilise heat pumps and district heating when assuming district heating networks are large.

At an individual level, a ground source heat pump consumes less electricity over the course of a year than an air source heat pump. This is thanks to the higher overall COP, which was previously discussed in Section 4.4.1.2 (page 196). At the district level, among the three topological configurations to employ heat pumps in district heating, T2 (using large scale heat pumps in a high temperature district heating network) consumes the highest amount of electricity per dwelling. Extra electricity is needed to generate more heat in the upstream of the network because of high levels of heat loss throughout transmission and distribution. Meanwhile, large scale heat pumps operate at relatively lower COPs in a high temperature network compared to their low temperature counterparts, which has been indicated in Figure 4.18.

In contrast, T3 (small individual booster heat pumps connected to a low temperature network) consumes the lowest amount of electricity per dwelling due to there being available heat sources and higher heat pump COPs. In addition, T4 (both large scale and small individual heat pumps are used in a low temperature network) consumes around 4,200 kWh per dwelling per year to meet heat demand, which is nearly 1,200 kWh higher than T3 because of the lack of free heat sources in the upstream of the system.

Based on different technology lifespans (DECC and AECOM, 2015), as well as the projected carbon intensity of the electricity grid in the UK (BEIS, 2019d), the carbon emissions associated with different heat pumps and district heating topological configurations have been modelled. Table 4.14 lists the annual and overall lifetime carbon emissions of different heating technologies.

Table 4.14: The overall lifetime and average annual carbon emission per dwelling from different heating options to meet heat demand.

Per dwelling	**Gas boiler**	**ASHP**	**GSHP**	**T2**	**T3**	**T4**
Technology lifetime (years)	15	20	20	50	50	50
Lifetime carbon emission (t)	43.86	12.01	10.60	23.34	14.35	18.39
Annual carbon emission (t)	2.92	0.60	0.53	0.47	0.29	0.37

As the results reveal, carbon emissions from heat pumps and district heating are significantly lower than gas boilers because of their higher degree of technological efficiency and the projected decrease in the carbon intensity of electricity over the next few decades. Furthermore, between different topological configurations to utilise heat pumps in district heating networks, topological configurations with low operating temperatures are associated with much lower carbon emissions due to high heat pump COPs and low network heat loss.

Also, utilising heat pumps in district heating networks leads to smaller average annual carbon emissions than installing air source or ground source heat pumps in individual dwellings. On average, throughout their technology lifetimes, an individual heat pump could reduce up to 82% of annual carbon emissions from heat when compared with using a gas boiler over a period of 20 years. Furthermore, suppose the carbon intensity of the electricity grid keeps declining as projected. In that case, low temperature district heating with individual small heat pumps could cut annual carbon emissions by up to 90% when a free heat source is available, in comparison with utilising a gas boiler over their technology lifespans.

This study makes use of the annual carbon intensity of electricity figures projected by BEIS (2019d) to model carbon emissions. However, the carbon intensity of the electricity grid may fluctuate in accordance with different seasons of the year and the level of renewable electricity generation, with higher carbon intensity occurring in the winter when the heat demand is high and lower intensity taking place in the summer months when the heat demand is low. By contrast, the carbon intensity of natural gas remains relatively stable over time. Therefore, the carbon emissions from heat pumps and district heating would be higher if the hourly carbon intensity of electricity was applied. Hence, these findings might underestimate the carbon emissions from electric heat pumps and district heating networks. Regardless, in the long term, heat pumps and district heating could well enormously reduce carbon emissions from domestic heating and might potentially revolutionise the domestic heating sector with decarbonised electricity.

4.4.2.3 Economic trade-offs among different heat pumps and district heating topological configurations and scales

Different heating options may have different cost structures, which may affect the deployment of different domestic heating technologies. This study categorises the costs of heat pumps and district heating networks into four groups: capital costs, O&M costs, fuel (gas or electricity) costs and carbon costs. This section discusses the economic results from the techno-economic model and evaluates the comparative economic advantages of utilising heat pumps and district heating in different topological configurations.

Comparisons are discussed according to their levelised costs over technology lifetimes, initial capital costs (to install heat pumps or construct heat networks) and gas or electricity costs of operating the topological configurations over a year to meet domestic heat demand. This section first explores costs across all four heat pumps and district heating topological configurations and compares them to the costs of individual gas boilers. It then discusses the economies of scale of district heating through analysis of the costs across five scales when district heating networks are operated with two types of heat pumps under high or low temperature levels.

Based on the four topological configurations and five scales of heat pumps and district heating networks defined in Section 4.1 (page 141), the lifetime costs of heating technologies are modelled to meet domestic heat demand via different topological configurations and compared to the costs of a gas boiler. This study assumes that heating technologies are used to generate heat for both space heating and domestic hot water for all dwellings connected to the networks. Figure 4.26 provides an overview of the levelised cost of heat (primary vertical axis) and the initial capital cost per dwelling (secondary vertical axis) across the four heat pumps and district heating topological configurations, assuming all district heating networks are large networks (with 1,500 dwellings connected) and that the baseline discount rate is 3.5%. The uncertainties of input assumptions and their impact on the overall LCOH results are discussed in Section 4.4.3 (page 240) with local and global sensitivity analyses. Moreover, a set of tornado graphs (Figures 4.43 to 4.45, page 261) illustrate the potential ranges of the LCOH for different heat pumps and district heating topologies, as well as how changes in these inputs affect the model results.

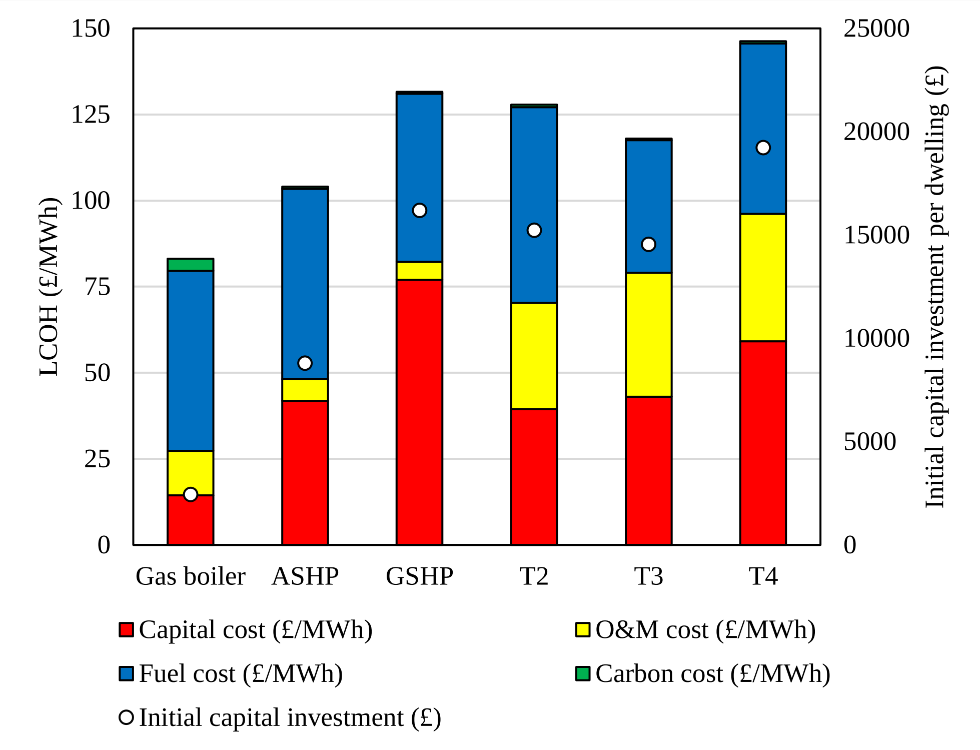

Figure 4.26: Overall LCOH and initial capital investment costs per dwelling for four topological configurations to utilise heat pumps and district heating, compared to a gas boiler.

As expected, a gas boiler has the lowest LCOH and initial capital investment of all heating options considered in this study, due to its significantly lower capital cost and the low price of gas. It costs less than £2,500 to install a gas boiler, and the LCOH is just above £83/MWh over its 15-year lifespan. In contrast, as discussed in Section 4.4.1 (page 202), installing an individual ground source heat pump is the most expensive way to meet heat demand on the individual scale, with the highest LCOH (£132/MWh) and initial capital investment (£16,200 per dwelling on average). Meanwhile, the LCOH and initial capital costs vary considerably with the different ways of utilising heat pumps in district heating networks.

Figure 4.26 reveals that Topology 3 has the lowest LCOH of the three district heating topological configurations, at £118/MWh when small heat pumps are used in dwellings connected to a low temperature district heating network with free heat sources. This is about 13% higher than the LCOH for an individual air source heat pump and about 42% more than the LCOH for a gas boiler. It is around 8% less than Topology 2 which uses centralised large heat pumps and high operational temperatures, 12% less than an individual ground source heat pump and almost a quarter less than Topology 4 (£146/MWh), which employs both large centralised heat pumps and small individual booster heat pumps in a low temperature district heating network.

However, this study assumes that a free heat source is connected to the district heating network in Topology 3, which reduces its overall costs to operate. Without a free heat source, additional heating measures are needed in order to generate heat at the upstream of the network, such as utilising large heat pumps in Topology 4. This leads to additional costs and carbon emissions associated with the centralised heat generating system. Moreover, although Topology 4 has the second lowest average annual carbon emissions (as pointed out in Table 4.14), its overall LCOH is the highest of all the heating options studied because of high capital investment.

Figure 4.26 also compares the initial capital costs for dwellings with different heating options. As the figure indicates, a ground source heat pump and Topology 4 have significantly higher initial capital costs per dwelling than other approaches using heat pumps or district heating, at more than £19,200 per dwelling on average. This number is reduced by over 26% and 32% per dwelling for topological configurations 2 (£15,200 per dwelling) and 3 (£14,560 per dwelling), respectively. Although the LCOH for Topology 3 is similar to the LCOH for an individual air source heat pump, the initial capital investment per dwelling is still nearly a third higher than that incurred in installing individual air source heat pumps.

Furthermore, Figure 4.27 provides an overview of three key results from the techno-economic modelling: the overall LCOH (vertical axis), the initial capital cost per dwelling (horizontal axis), and average annual carbon emissions per dwelling (coloured squares) for different heating options to meet heat demand. As the figure illustrates, to replace individual gas boilers and move away from gas heating, installing heat pumps at individual dwellings is the cheapest option (both in terms of the overall LCOH and initial capital cost per dwelling): either utilising air source heat pumps at individual dwellings as standalone heat supplying technologies or using booster heat pumps that connect to district heating networks to utilise free heat sources (Topology 3).

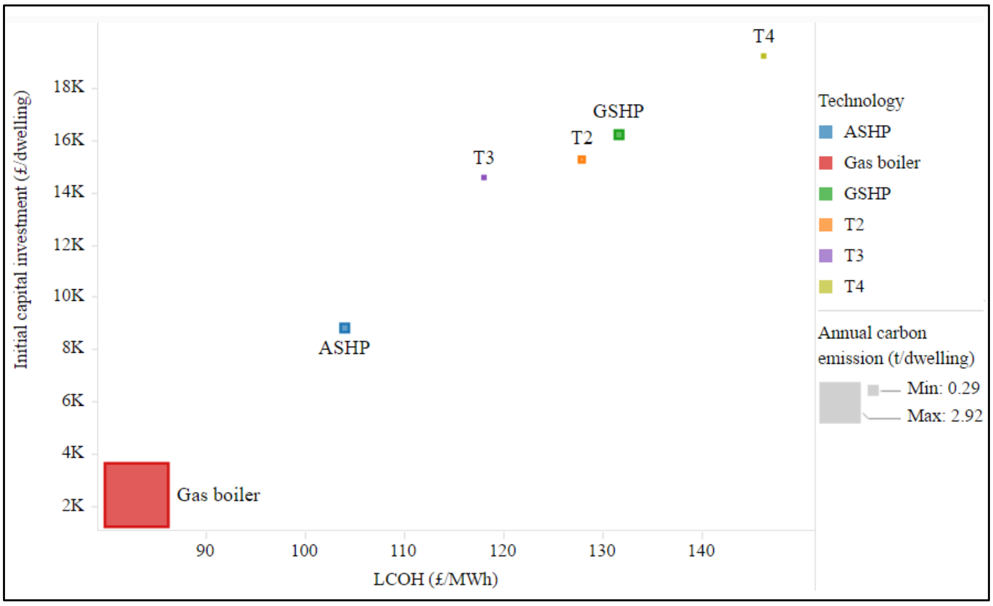

Figure 4.27: An overview of the overall LCOH (£/MWh), initial capital investment costs (£/dwelling), and average annual carbon emissions (t/dwelling) for four topological configurations utilising heat pumps, compared to a gas boiler.

On the other hand, individual ground source heat pumps and district heating Topology 4 are the most expensive ways to meet heat demand as discussed previously, even though they have lower annual carbon emissions per dwelling than individual air source heat pumps. Therefore, when there are no available free heat sources, a high temperature network with large centralised heat pumps may have lower LCOH and initial capital cost per dwelling than a low temperature network with both large centralised heat pumps and individual booster heat pumps. Although the low temperature networks in Topology 4 have lower heat loss and electricity consumption, the capital cost to install both large centralised heat pumps and individual booster heat pumps is much higher than the capital cost of Topology 2.

Figure 4.28 illustrates the composition of the overall LCOH according to different cost elements, assuming all district heating networks are large networks. For an individual gas boiler, capital cost contributes less than 20% of the overall LCOH, and fuel (gas or electricity) cost contributes to more than 60%. In contrast, for an individual ground source heat pump, capital cost contributes to almost 60% of the overall LCOH. For individual technologies, O&M costs contribute to only a small percentage of the overall LCOH.

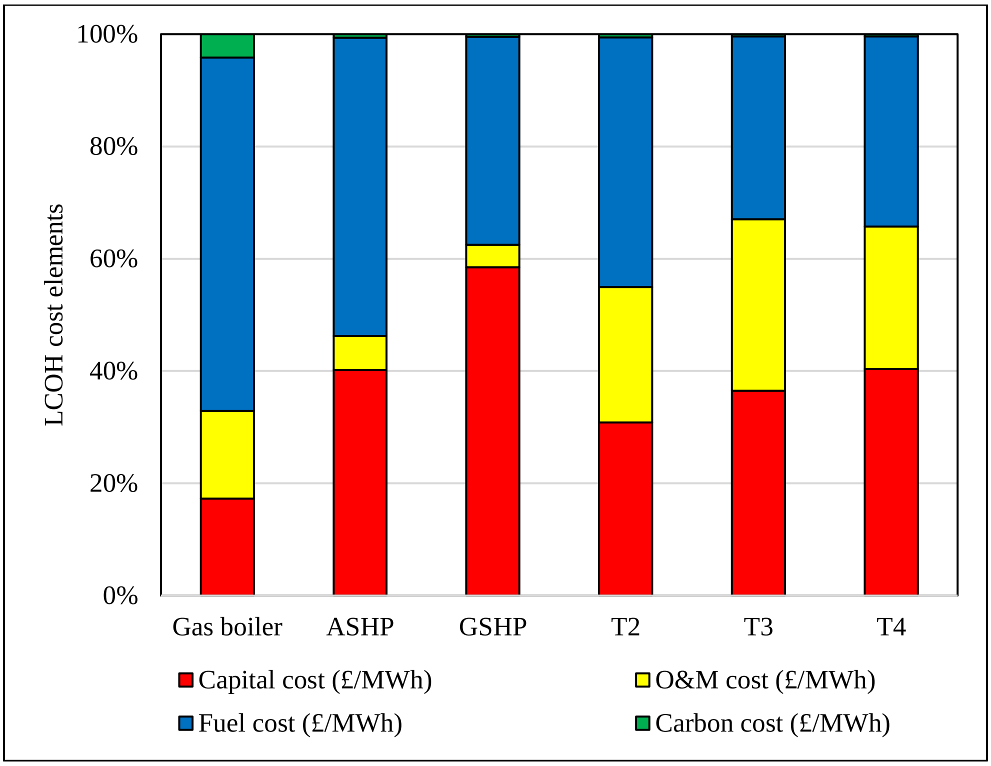

Figure 4.28: Components of overall LCOH for four topological configurations to utilise heat pumps and district heating, compared to the LOCH for a gas boiler.

However, for the three district heating topological configurations, the proportions of O&M cost become relatively larger, ranging between 24% and 30%. In particular, for a district heating network that utilises small individual heat pumps (Topology 3), although this topological configuration has the lowest overall LCOH, O&M cost is the largest component of its LCOH, due to O&M costs of individual booster heat pumps.

For individual heat pumps, O&M costs only contribute to a small proportion of the overall cost due to their low heat pump maintenance cost. As shown in Table 4.5 (page 186), the annual O&M costs of individual heat pumps are below £100 per year (data from Pöyry (2009) and Delta-ee (2012)), and these are mainly for technology maintenance and labour costs at individual dwelling level. However, for heat pumps in district heating networks, additional costs are needed to operate and maintain different subsystems of the district heating networks. For example, as shown in Table 4.7 (page 190), besides maintenance costs of heat pumps (large centralised heat pumps or small booster heat pumps), additional costs may occur from heat meters maintenance, substations and HIUs maintenances, transmission and distribution pipes maintenances, and extra labour costs for metering, billing and revenue.

District heating O&M costs vary based on specific system designs and operations. Detailed district heating O&M costs are rarely publicly available because they are commonly considered as commercially sensitive data by district heating operators. This study gathers O&M costs data of different district heating components from DECC and AECOM (2015), based on data collected from existing district heating networks in the UK. Because the majority of the district heating networks assessed by DECC and AECOM (2015) were small networks, these data may not be representative of large district heating networks.

As a district heating network get larger and more complex, with additional components added to the system. This tends to increase maintenance and capital costs for the network, but costs upstream may reduce because of greater energy conversion efficiency such as utilising more efficient heat pumps. Moreover, when a district heating network becomes larger, O&M costs could be reduced by employing highly skilled and knowledgeable staff to plan and undertake maintenance work. Small district heating schemes may be unable to employ such staff and may therefore have higher O&M costs in the long run. To access the impact of uncertainties in O&M costs, sensitivity analysis is conducted, with tornado graphs to show the relative importance of all cost elements to the overall LCOH, including different subcomponents of district heating O&M costs (page 261).

Nevertheless, high proportions of capital and O&M costs should not always be treated as disadvantages, as these costs are spent on local development, constructions or employment, whereas fuel costs may contribute to fuel imports. Additionally, due to the projected decreasing carbon intensity of electricity and very low future carbon prices in the UK, carbon costs only contribute to very small proportions of the overall LCOH for all heating options, accounting for less than 5% for a gas boiler and less than 1% for all topological configurations that utilise heat pumps or district heating networks.

Furthermore, as described in Section 4.4.2.2 (page 216), because different topological configurations may be associated with different heat pump efficiencies, additional electricity is needed to compensate for heat loss in distribution and auxiliary electricity consumed in the system (such as pumping energy). Thus, overall fuel consumption (gas for boilers and electricity for heat pumps and district heating) differs, as demonstrated in Figure 4.25. Applying the fixed residential annual gas and electricity prices provided by BEIS (2019d), the average gas or electricity costs per dwelling over one year among all heating options are modelled, and results are presented in Table 4.15.

Table 4.15: Average annual gas or electricity costs per dwelling for all heating options; fuel prices are from BEIS (2019d).

Annual gas or electricity costs	**Gas boiler**	**ASHP**	**GSHP**	**T2**	**T3**	**T4**
Per dwelling (£)	693	744	657	902	532	757

Although the model assumes that residential electricity prices are close to three times higher than residential gas prices (BEIS, 2019d), the annual electricity costs for individual heat pumps are not dramatically higher than those for gas boilers, due to high heat pump COPs. Furthermore, thanks to low heat loss from the low temperature network and free heat source, Topology 3 has the lowest electricity consumption and the annual cost per dwelling. This is over 40% lower than the electricity cost for Topology 2, which operates with large centralised heat pumps and higher network temperatures. Table 4.15 compares gas or electricity costs per dwelling under the same electricity pricing. However, as big consumers, district heating networks typically operate with different electricity pricing schemes negotiated with electricity providers, often cheaper than individual households' retail electricity prices.

In addition to accessing the four topological configurations to utilise heat pumps and district heating to meet domestic heating demand, this techno-economic model evaluates the economies of scale of district heating and how this may affect the economics of a network and the cost-competitiveness of different district heating topological configurations on different scales. As the size of a district heating network changes, its key components also need to change, including the capacities of the centralised heat pumps (for topological configurations 2 and 4) and appropriate primary (transport) pipes, the total length of district heating pipes, the size of substations, HIUs and heat meters. Hence, the technical performance of the network, such as heat pump COPs, heat loss and overall electricity consumption, varies across different scales, as do the costs to construct and operate the district heating network.

When the number of connected dwellings in a district heating network increases, larger and longer transport pipes may be required in the network, potentially leading to higher overall heat loss and pipe costs (as shown in Figure 4.20). However, as previously demonstrated in Figure 4.23 and Figure 4.24, the overall heat loss from a district heating system, as a percentage of its overall heat generation, decreases under the same operating conditions when the scale of the district heating network gets larger. The average heat loss per dwelling decreases when more dwellings are added to the network, and, therefore, on average, electricity consumption per dwelling declines (as Figure 4.29 demonstrates). For example, the average electricity consumption per dwelling per year of a Topology 2 heat network declines from about 5,700 kWh to less than 4,900 kWh, when the network grows in scale from a small district heat network (with 100 dwellings) to a medium multi-developments network (with 10,000 dwellings). Consequently, the average electricity consumption and its associated cost per dwelling can be reduced when the scale of a district heating network becomes larger.

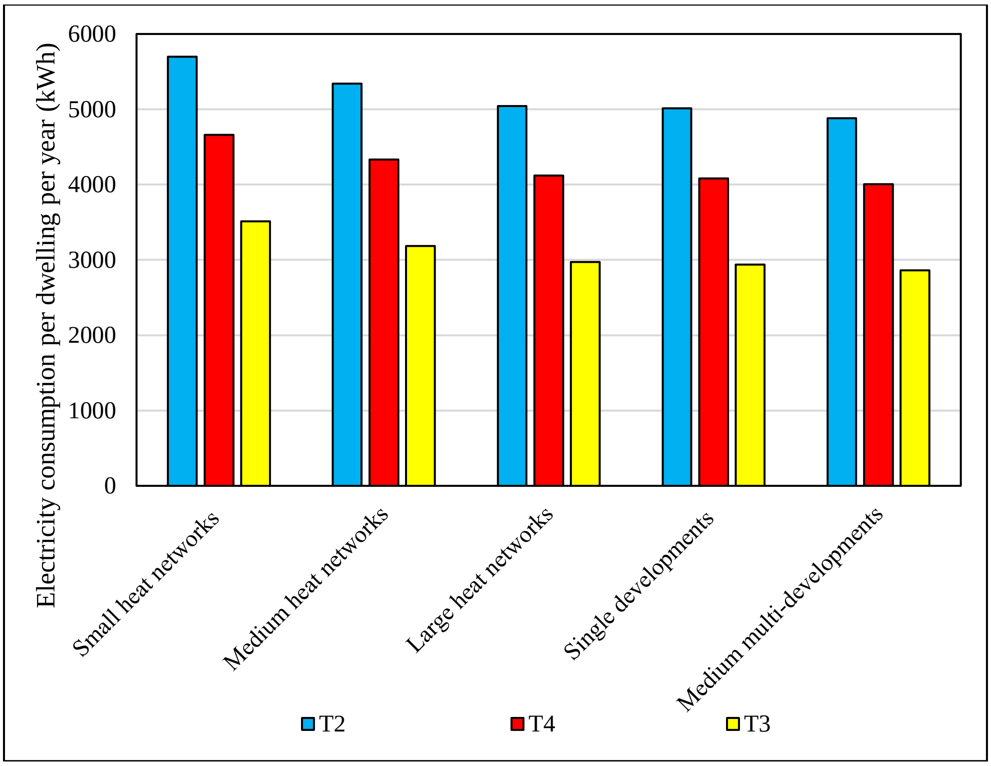

Figure 4.29: Average electricity consumption per dwelling per year across the five district heating scales and three topological configurations.

Figure 4.30 compares the overall LCOH (primary vertical axis) and the initial capital costs per dwelling (secondary vertical axis) across the five district heating scales when the networks utilise centralised large scale heat pumps at high operational temperatures (Topology 2). As the figure shows, economies of scale arise in district heating networks, as the overall LCOH decreases steadily from a small district heating network to a medium multi-developments network, from over £144/MWh to £125/MWh, with a decrease of around 15%. Meanwhile, the initial capital cost per dwelling drops by roughly 20%, from approximately £18,500 to £14,800 per dwelling.

Under the same topological configuration, the unit charge to operate the system remains as the largest cost element of the overall LCOH. In contrast, the proportion of capital cost becomes gradually smaller when the scale of the district heating network increases, as shown in Figure 4.31. For a small district heating network, capital cost accounts for more than one-third of the overall LCOH, whereas for the largest district heating network, the capital cost is reduced by over three percentage points, to about 30% of the total LCOH.

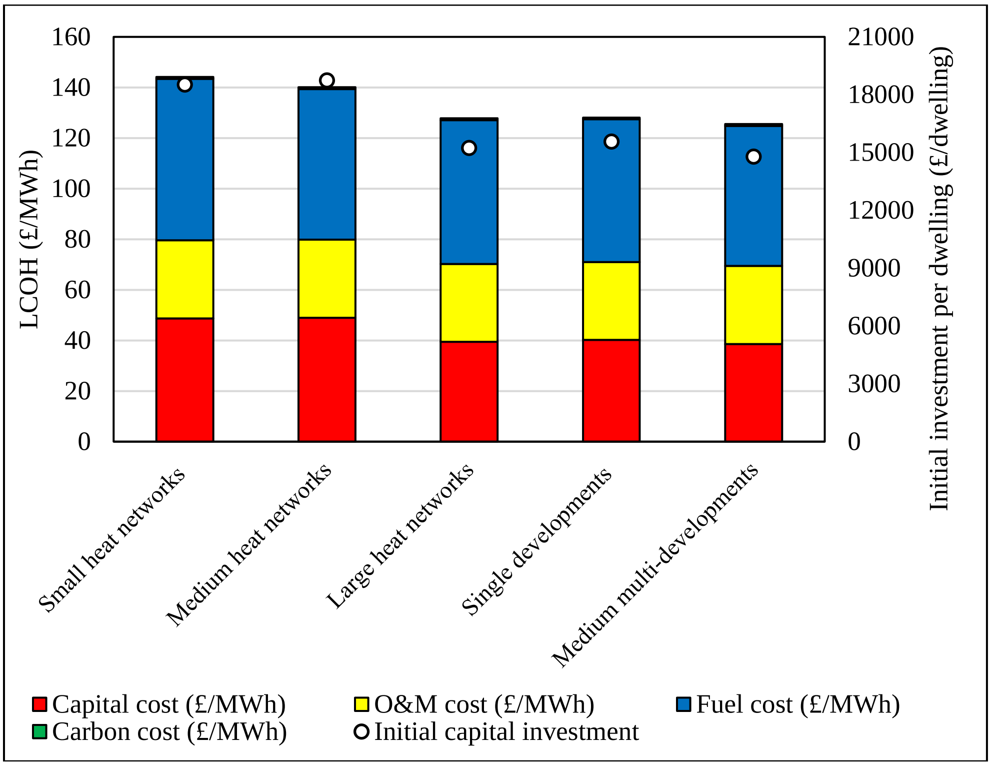

Figure 4.30: Overall LCOH and initial capital investment costs for district heating networks with large heat pumps (Topology 2) across the five district heating scales.

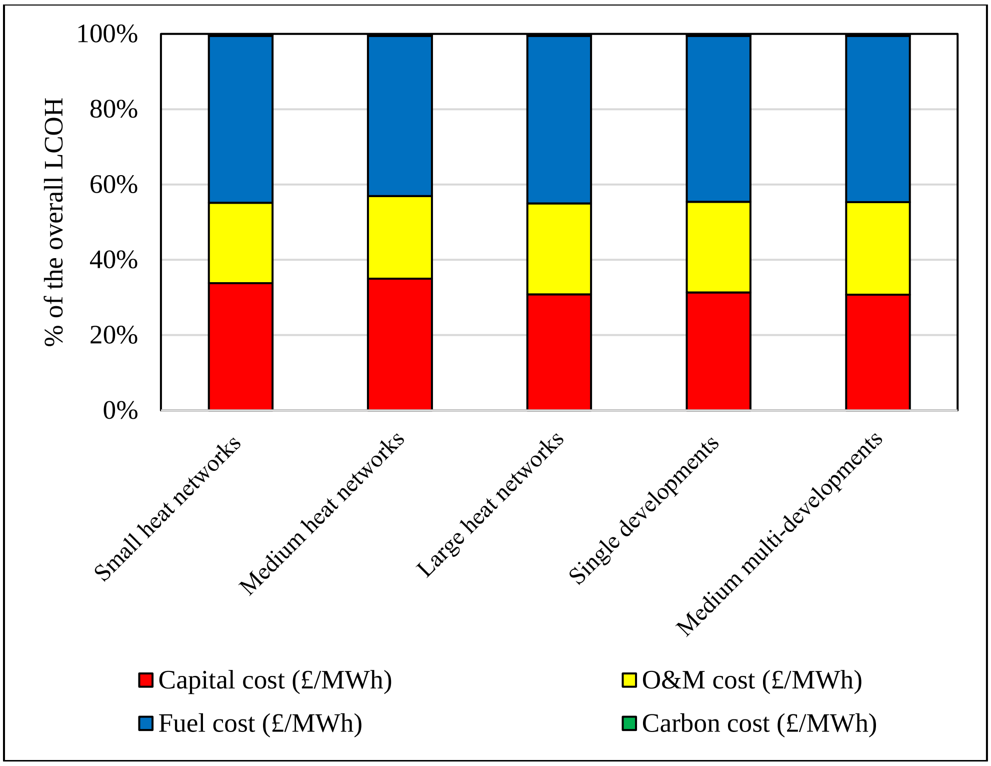

Figure 4.31: Components of the overall LCOH for district heating networks with large heat pumps (Topology 2) across the five district heating scales.

In addition, Topologies 3 and 4 have the same level of heat loss, because their distribution systems are the same, and both topological configurations function at low operational temperatures (30 °C flow and ambient return). The key difference is that in Topology 4, additional electricity is consumed by the central large heat pump, due to the lack of direct free heat sources, which are present in Topology 3. Similar to Figure 4.30 and Figure 4.31, Figure 4.32 provides an overview for topological configurations 3 and 4 of the overall LCOH, initial capital costs per dwelling and cost components as percentages of the overall LCOH across the five district heating scales when the networks operate with low operational temperatures.

As the LCOH results in Figure 4.32 demonstrate, same as Topology 2, the overall LCOH and initial capital costs per dwelling decline in topological configurations 3 and 4 when the scale of the district heating network increases. For Topology 3, where only small individual heat pumps are installed, the LCOH and initial capital costs per dwelling decrease slightly, from over £125/MWh and £14,700 per dwelling, to £115/MWh (8% reduction) and £14,000 per dwelling (5% reduction), respectively. Moreover, the overall LCOH and initial capital costs per dwelling for the more capital-intensive Topology 4 show a greater decrease, from £168/MWh and £22,500 per dwelling, to £147/MWh (14% reduction) and £18,800 per dwelling (20% reduction), respectively.

In terms of cost elements as percentages of the overall LCOH, capital cost and electricity cost each contributes to more than 35% of the overall LCOH for Topology 3. For Topology 4, due to the cost to install large centralised heat pumps, the capital cost is a slightly higher percentage of the overall LCOH, accounting for over 40%. In comparison, the O&M cost and electricity cost contribute to less than 25% and 35% of the overall LCOH, respectively. Additionally, due to very low carbon emissions and projected carbon prices, carbon costs contribute to less than 0.5% of the overall LCOH for both topological configurations.

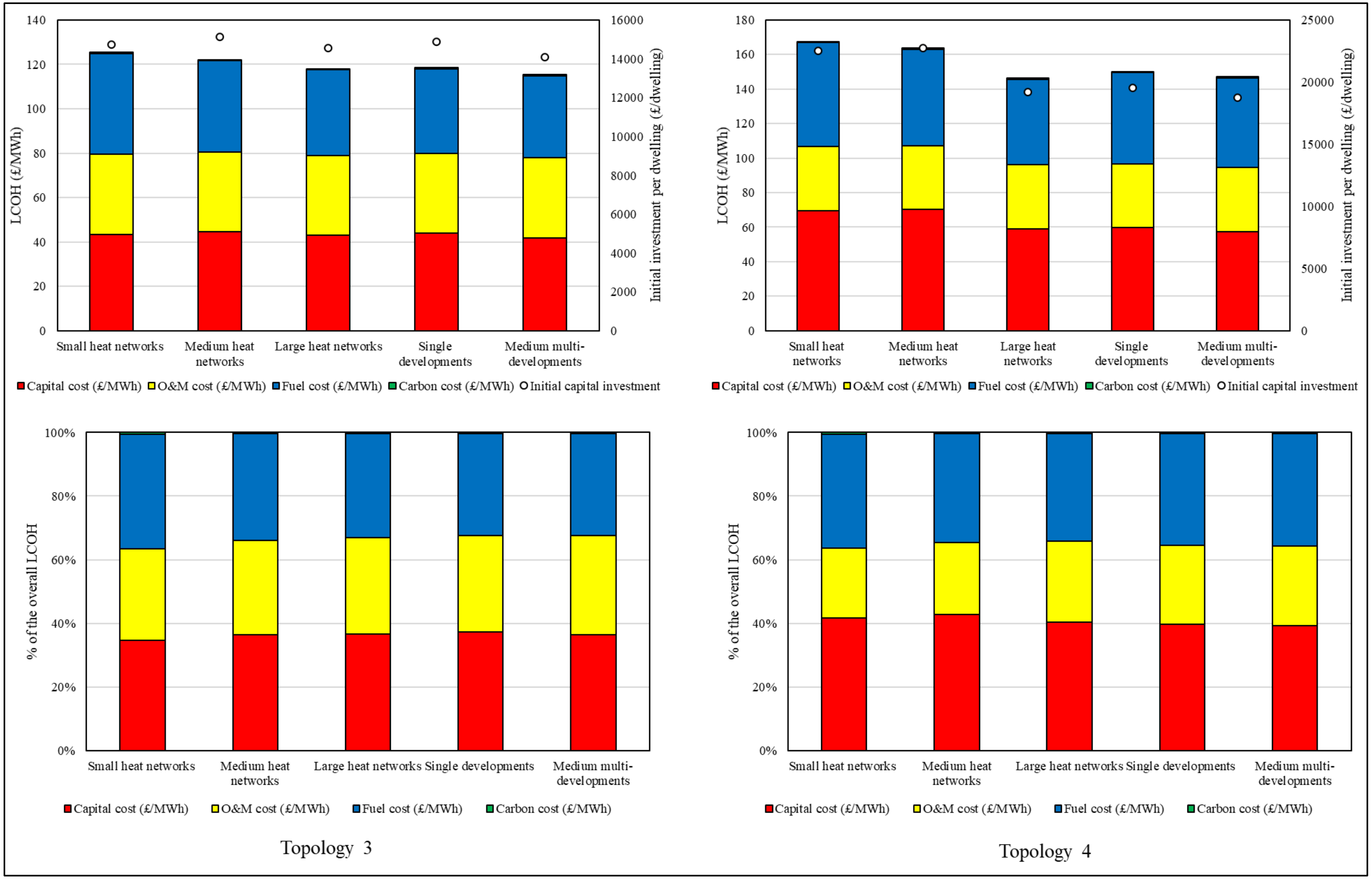

Figure 4.32: Initial capital investment per dwelling, overall LCOH and its components for Topology 3 and 4 across the five district heating scales.

4.4.2.3.1 Non-economic barriers to deploying heat pumps and district heating networks in the UK

The previous sections of this chapter discussed the comparative economic and environmental advantages of different approaches to utilising heat pumps and district heating networks. In reality, the decision regarding which heating option a dwelling or a group of dwellings would implement is a complex issue. Heating technologies' costs and energy bills are critical features. However, many other matters or restrictions can affect the uptake rate of heat pumps and district heating networks. Various non-economic barriers could limit the development and deployment of heat pumps and district heating networks for the UK's dwellings.

To switch from gas-fired heating to electric heat pumps on a large scale, the UK may require substantial investment in energy infrastructures to manage peak electricity demand and to ensure the supply of decarbonised electricity. Additional local planning and investment in district heating networks and energy centres are necessary as there are very limited numbers of district heating networks currently operating in the UK. Individual heat pumps are, in general, larger than individual gas boilers. They may require access to heat sources and extra space for hot water storage systems, which could limit their deployment.

Moreover, the UK's current building stock characteristics are not ideal for the direct deployment of heat pumps or low temperature district heating networks. UK dwellings tend to have higher thermal losses and high temperature radiators (Hannon, 2015); these could lead to low system efficiency, poor technology performance, and unsatisfied customers. Besides, occupant related barriers may also restrict the deployment of heat pumps and district heating. For example, heat pump field trials revealed that there was inadequate end-user instruction regarding how to operate heat pumps, and UK households tend to operate heating systems in bursts with high peak flow temperatures, leading to poor technology performance (EST, 2013). Additionally, heat pumps and district heating installations require trained engineers to ensure safety and accurate assessment of individual and aggregated heat demand to avoid over- or under- dimensioning and ensure technology efficiency.

4.4.3 Uncertainties and limitations of model inputs and assumptions and sensitivity analysis

Heat pumps and district heating systems are technologically sophisticated, involving complicated interactions between various sub-systems and technical components. The costs to construct and operate heat pumps and district heating networks are determined by the costs of their sub-systems and technical features. This study's primary purpose is to evaluate the comparative economic and environmental advantages of different district heating topological configurations of heat pumps. In this study, a techno-economic model is used to model heat pumps and district heating networks' critical technical and economic components.

The constructed model is based on a range of data inputs and assumptions, much of which are exogenous data that have been collected from previous studies or parametrised based on defined assumptions. However, there are limitations and considerable uncertainties regarding these data inputs and assumptions, such as future fuel prices, district heating pipe selections, and heating technology performance. Therefore, model uncertainty and sensitivity analyses are conducted to evaluate the model and its results.

Sensitivity analyses are useful techniques for scrutinising the impact that changes in the independent variables (model input parameters) have on the dependent variables (model results), as well as providing a better understanding of the correlations between them (Saltelli et al., 2000). The techno-economic model has a range of data inputs and underlying assumptions, and its results can be substantially affected by variations in the model inputs. Thus, model uncertainty and sensitivity analyses were conducted to evaluate the model and its results with qualitative interpretations. Besides, how sensitive the model results are to the use of different cost and technical parameters in the model is compared.

Two approaches were conducted to carry out the multidimensional sensitivity analyses on the different uncertain input parameters and the potential error ranges of the results depending on the type of data or assumption. First, local sensitivity analyses of single parameters are conducted (Saltelli et al., 2004) to evaluate their uncertainties. The levelised cost method that is applied in this research is a forward-looking method that models the studied heating technologies over the next five decades. The local sensitivity analyses evaluate four major input parameters that are independent of district heating operation strategies, namely discount rates, types of fuel prices, projected carbon intensities of the electricity grid, and district heating transport pipes.

There is significant uncertainty concerning these parameters, and they are difficult to predict or quantify. However, they could significantly affect the overall lifetime costs and environmental performance of heat pumps and district heating networks. To make different district heating topological configurations comparable, the model results from a large district heating network (with 1,500 dwellings) are used as a reference point, and the targeted variables are adjusted in order to evaluate their impact on the overall system costs or carbon emissions, while all the other model inputs are kept the same.

Second, global sensitivity analyses (Saltelli et al., 2000; Iooss and Lemaîtrem, 2014) with Monte Carlo simulations are conducted to assess the model's multiple critical technical and economic variables. The Monte Carlo approach is applied to quantitatively explore the sensitivities of the model results concerning all of the heating options and a number of interacting input parameters, such as heat demand, system capacities, network pipe features, technology efficiencies, and cost elements. This approach quantifies the importance of the input parameters concerning the overall costs for the use of heat pumps and district heating networks in the different topological configurations.

This study uses the same process that is applied by the IEA, NEA and OECD (2015) and that was used to evaluate the impact of a ±50% change in model parameters on the levelised cost of electricity. The Monte Carlo simulations were performed and visualised through Palisade Decision Tools (Palisade, 2020) to evaluate to what extent and which of the techno-economic model's input parameters have the most substantial influence on the overall system costs when heat pumps are utilised via different topological configurations.

4.4.3.1 Uncertainties of single parameters

4.4.3.1.1 Discount rates

The discount rate is a crucial factor that affects the results of the levelised costs as it determines the net present value of the future cash flows of all heating options over their lifetimes. The techno-economic model is developed based on a discount rate of 3.5%, which, according to the UK HM Treasury (2018), is the 'social rate of time preference' for the appraisal of policy programmes and investments. However, this number often varies according to the types of investments and investors in different countries. For example, discount rates of 10% or higher are often used to analyse risky businesses or investments in the UK. In this section, the discount rate is adjusted to demonstrate its impact on the overall LCOH of different heating options. Figures 4.33 and 4.34 illustrate how the LCOH changes from the baseline when the discount rate is altered between 1% and 10% discretely.

As expected, the LCOH rises when the discount rate increases for all heating technologies, as the two figures show. A gas boiler is the least sensitive to the variations in the discount rate, and the more capital intensive the heating technology is, the more sensitive it is to the changes in the discount rate. For example, under the baseline discount rate, the LCOH for an air source heat pump is £103/MWh. When the discount rate rises to 10%, the LCOH for an air source heat pump increases by over 22% (to £127/MWh). In comparison, the LCOH for Topology 3 or Topology 4 increases by more than 40%, while the LCOH for a gas boiler only rises by around 10%.

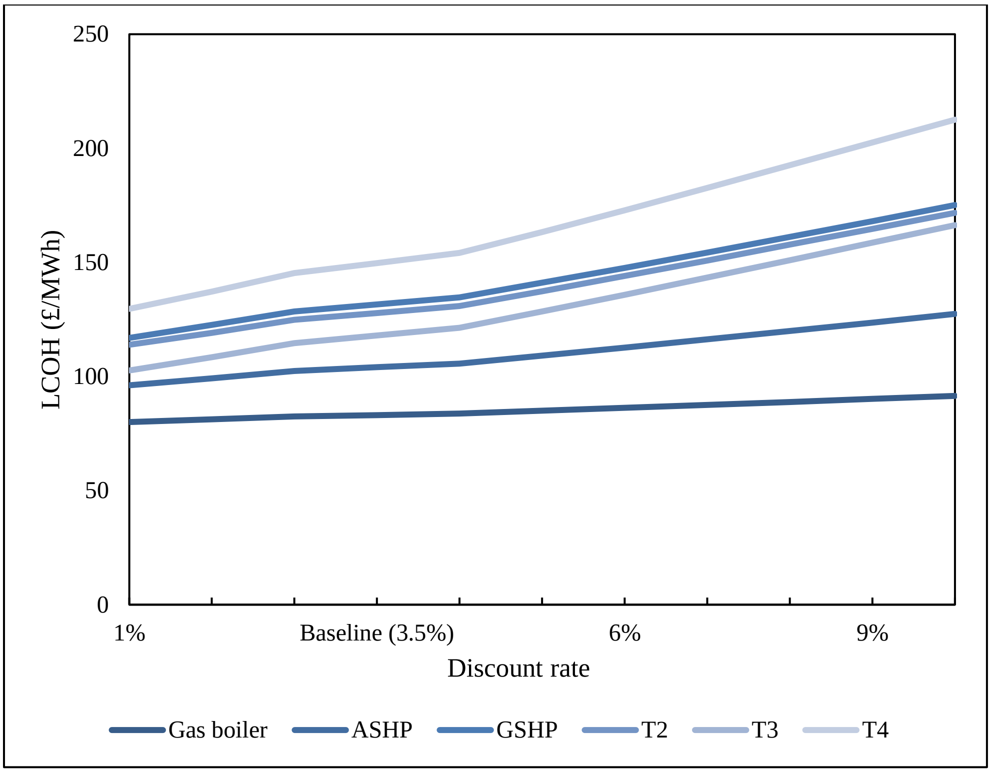

Figure 4.33: The overall LCOH for different heating options with different discount rates.

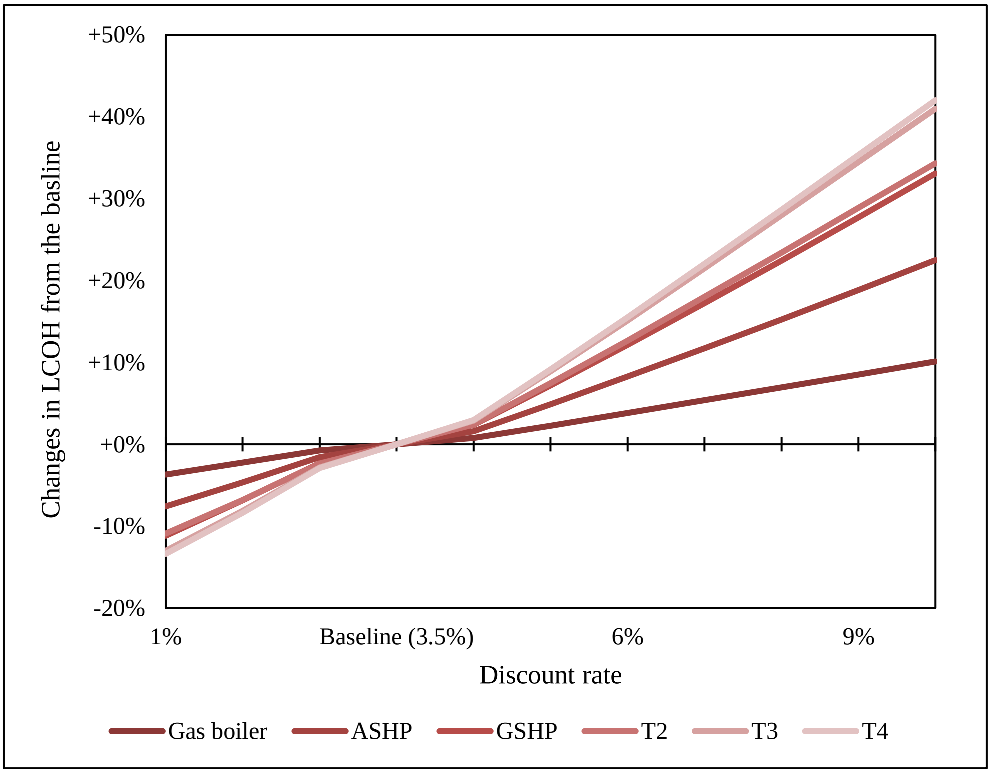

Figure 4.34: Variations in the overall LCOH from the baseline for different heating options with different discount rates.

4.4.3.1.2 Electricity prices

Although the prices of electricity are generally determined by its demand and supply, in the long-term, future electricity prices are affected by numerous uncertain factors, such as macro-economic factors, geopolitics, renewable technologies innovations and the price of fossil fuels. It is very difficult to forecast future electricity prices, and they could fluctuate significantly throughout the lifetime of the heat pumps and district heating networks. In order to conduct a comparison across all heating options, the same electricity pricing projection (BEIS, 2019d) is applied for all heat pumps and district heating networks.

However, it is possible that there could be a difference between the electricity tariff for households that utilise individual heat pumps and households that are connected to district heating networks. In general, a district network operator may be able to buy electricity at a cheaper price than individual households due to lower transaction costs and higher flexibility. Therefore, wholesale electricity prices tend to be much lower than retail prices, and this could reduce the electricity cost for district heating operators. Instead of appraising the potential future electricity prices, the sensitivity analysis evaluates the impact of fuel price changes on the LCOH for district heating networks by comparing the projected retail and wholesale electricity prices from the results of BEIS's (2019) Dynamic Dispatch Model.

Figure 4.35 reveals the annual gas or electricity cost per dwelling (top figure) and the overall LCOH for different heating options (bottom figure) when the district heating topological configurations adopt two different types of electricity prices. As expected, the annual gas or electricity costs for district heating networks drop significantly when electricity prices are switched from retail prices to wholesale prices. Using wholesale electricity prices for the district heating networks makes meeting the heat demand via district heating networks with heat pumps relatively cheaper than installing individual air or ground source heat pumps, as the overall LCOH for Topologies 2 and 3 could decrease by about 32% and 23%, respectively.

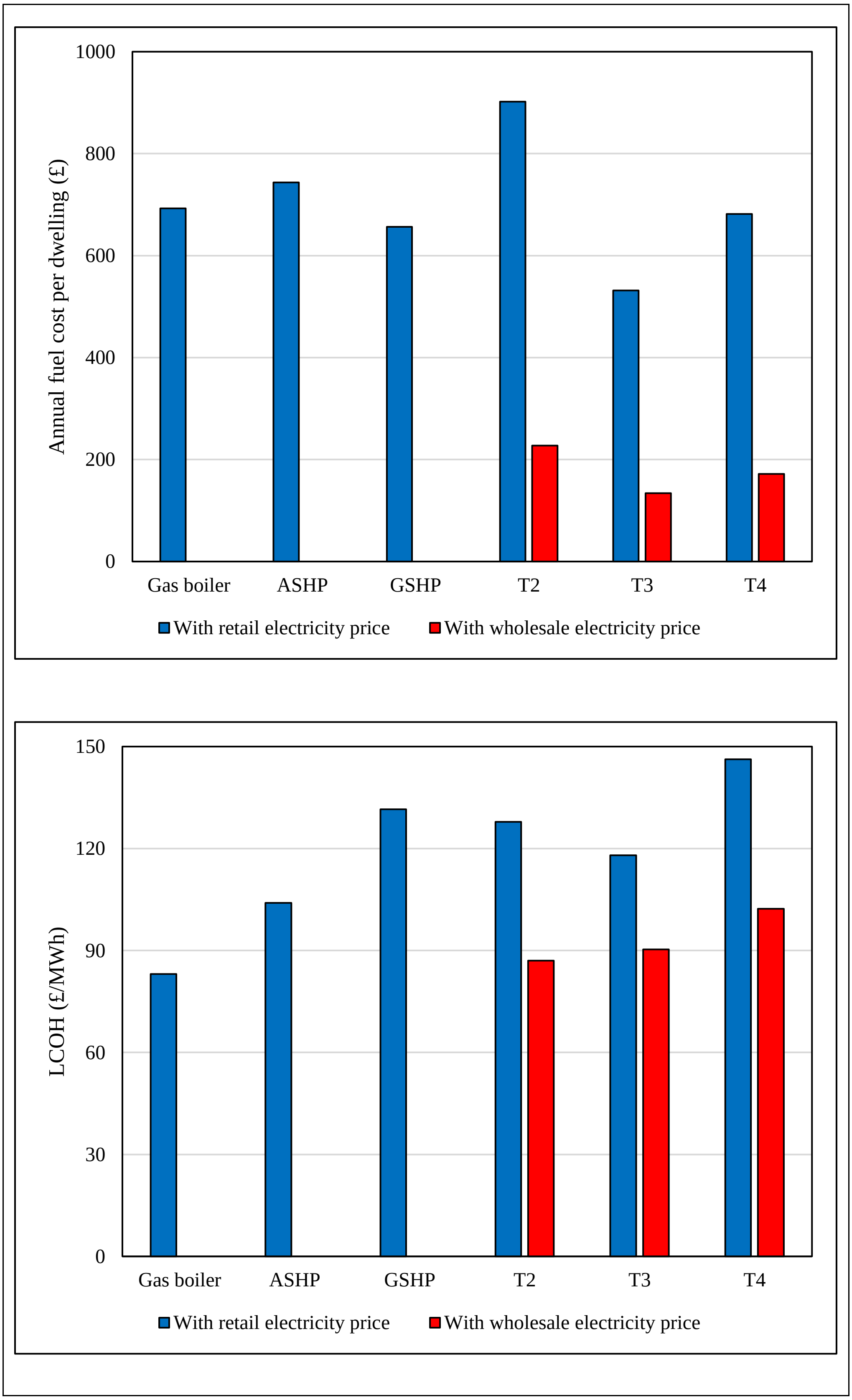

Figure 4.35: Changes in fuel prices and the overall LCOH when wholesale electricity prices are applied in district heating networks.

Additionally, assuming that wholesale electricity prices are used for district heating networks, Figure 4.36 shows that there is the potential to dramatically reduce proportions of the electricity cost of the overall LCOH of the heating options over their lifetime. For example, the proportion of the electricity cost of the LCOH for Topology 2 decreases by 28 percentage points from almost 45% to 17%.

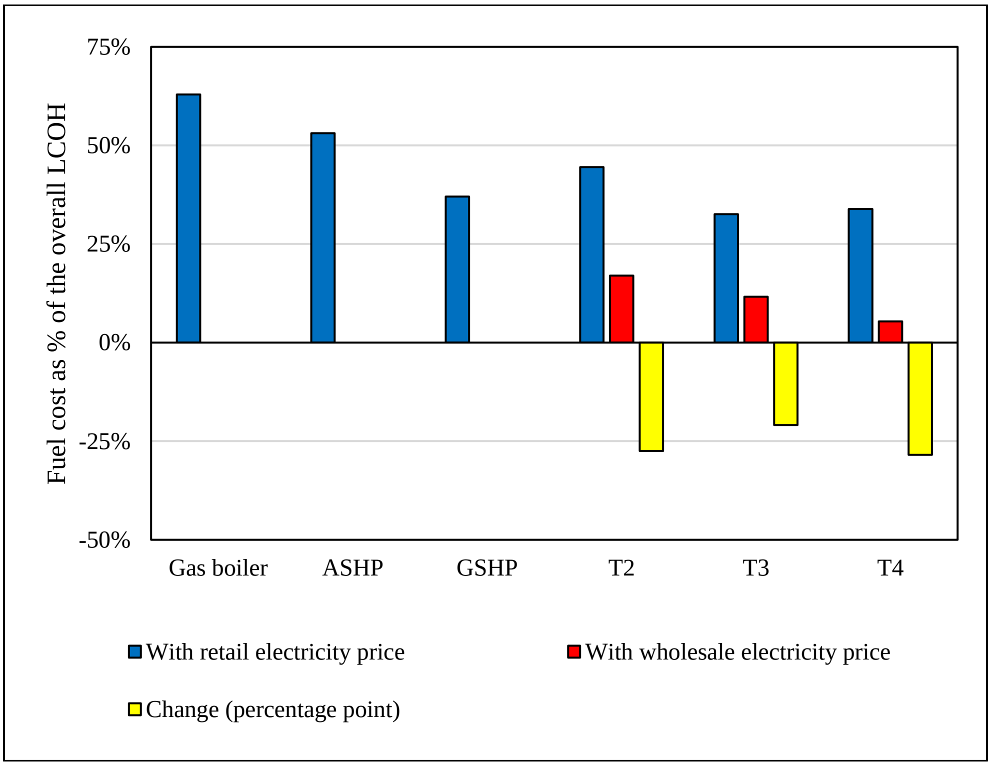

Figure 4.36: Changes in gas or electricity costs as a percentage of the overall LCOH when wholesale electricity prices are applied in district heating networks.

4.4.3.1.3 Uncertainties in the projected carbon intensity of electricity

Unlike individual gas boilers, which consume natural gas and release greenhouse gas emissions onsite, electric heat pumps and district heating networks do not generate carbon emissions at an individual household level. However, there are carbon emissions associated with heat pumps and district heating if the electricity is not decarbonised. Therefore, this study models their carbon emissions based on their technology efficiency, amount of electricity consumption, and the projected carbon intensity of the electricity grid.

Although the carbon intensity of natural gas will remain stable for years, the carbon intensity of the electricity grid constantly varies depending on the combination of electricity generated from different sources, including fossil fuels, renewables, and nuclear. This study adopts the projected yearly carbon intensity of electricity from the government's updated energy and emissions projections (BEIS, 2019d). The results are illustrated in Figure 4.37.

Figure 4.37 demonstrates the assumed projected changes in the carbon intensity of the electricity grid compared to gas up to the year 2050. It is projected that the carbon intensity of electricity will keep decreasing over the next few decades, thanks to the growth of renewable electricity generation. Due to a lack of data and the long lifetime of district heating networks, this study assumes that the numbers remain the same after 2050. Nevertheless, the projection of the carbon intensity of the electricity grid is highly uncertain and is scenario dependent.

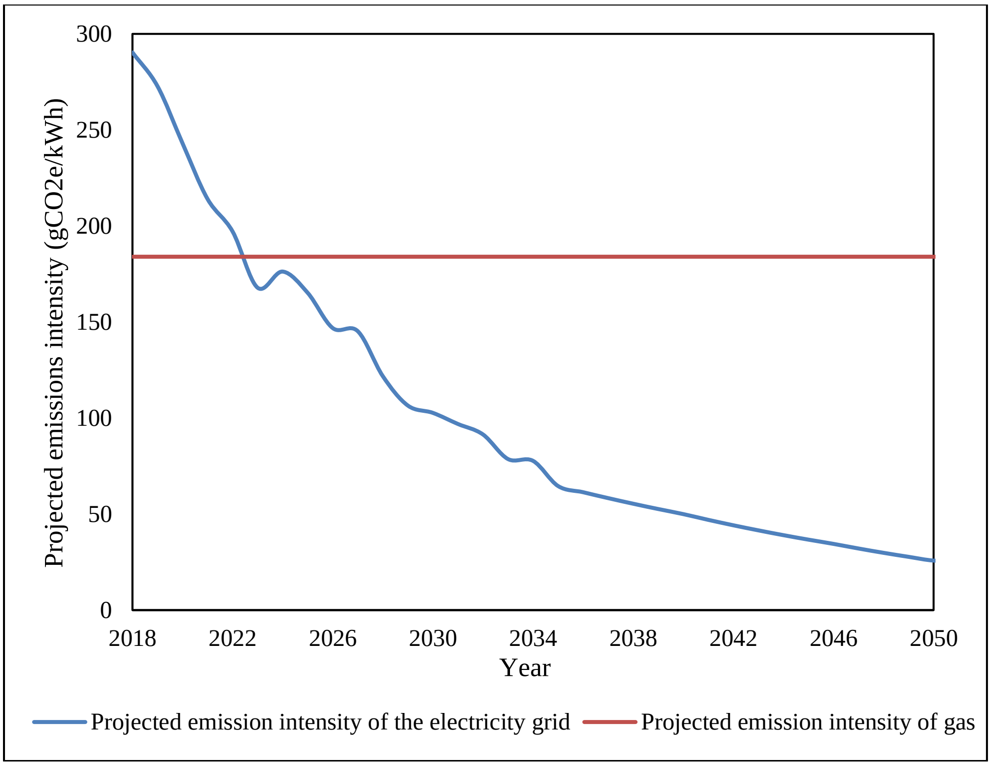

Figure 4.37: Projected carbon intensity of natural gas and electricity up to 2050 in the techno-economic model.

There are uncertainties regarding how fast the electricity grid will decarbonise, and complex modelling is needed to estimate and quantify the carbon intensity of electricity in future years. Recent data proposes that the estimated carbon intensity of the electricity grid in the UK is lower than previously estimated (National Grid ESO, 2020) and that the rate of decarbonisation of electricity may accelerate as the UK aims to achieve net-zero greenhouse gas emissions by 2050 (CCC, 2019; 2020).

For example, Figure 4.38 illustrates the projected carbon intensity of electricity in the Balanced Net Zero Pathway proposed by the CCC (2020) for the UK's sixth Carbon Budget. It suggested that the UK's electricity system should be almost decarbonised by 2035, and in order to achieve this, significant additional investment in deploying renewable electricity generation will be required.

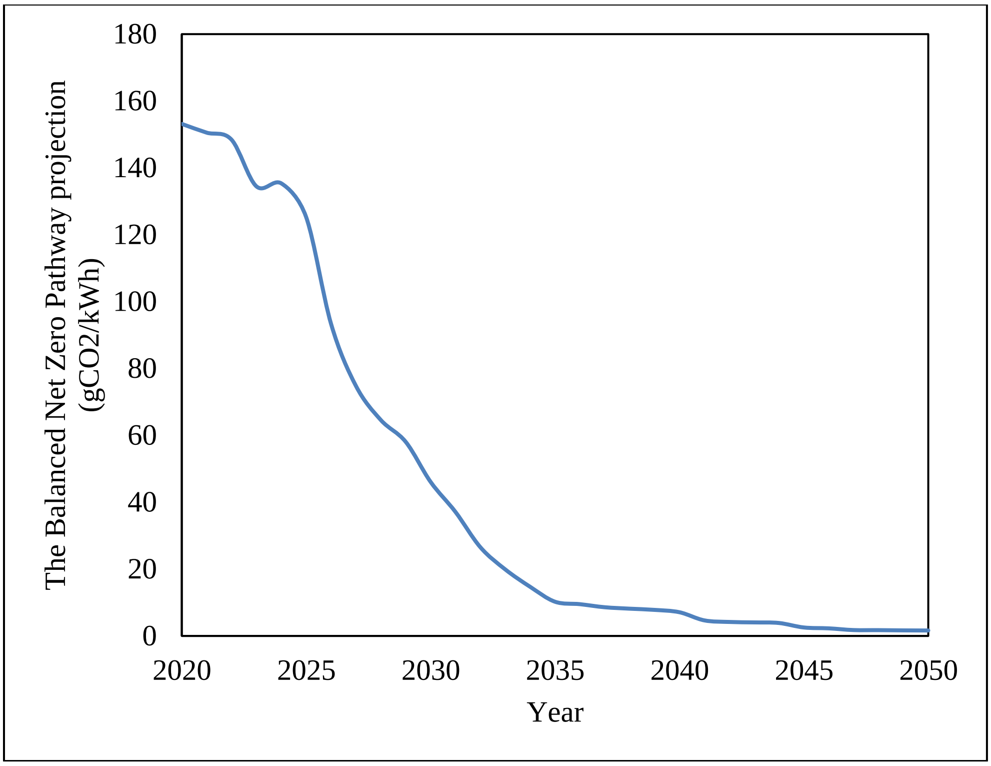

Figure 4.38: Projected carbon intensity of electricity in the Balanced Net Zero Pathway by the CCC (2020).

To assess the impact of future changes in the carbon intensity of electricity on the amounts of carbon emissions from heat pumps and district heating networks over their lifespans, three additional sets of the future carbon intensity of electricity are evaluated:

1. The future carbon intensity of electricity follows the government's projection as a reference case.
2. The future carbon intensity of electricity is altered by +50% of the government's projection.
3. The future carbon intensity of electricity is altered by -50% of the government's projection.
4. The unlikely situation that the future carbon intensity of electricity remains the same after 2018.

The carbon emissions associated with the different topological configurations for the use of heat pumps and district heating networks are modelled according to the four different sets of the carbon intensity of electricity. The modelled average annual carbon emissions of the different heating options are shown in Figure 4.39, and the reduction in carbon emissions gained from using heat pumps and district heating rather than a gas boiler is summarised in Table 4.16.

Table 4.16: Reduction in carbon emissions from heat pumps and district heating compared to a gas boiler under four sets of the carbon intensity of electricity.

Carbon intensity of electricity	**ASHP**	**GSHP**	**T2**	**T3**	**T4**
Projected carbon intensity of the electricity grid by BEIS	79%	82%	83%	90%	86%
Projection +50%	69%	73%	80%	88%	83%
Projection -50%	90%	91%	93%	96%	95%
Carbon intensity of the electricity grid remains the same after 2018	59%	64%	50%	70%	59%

As the results indicate, due to their higher technology efficiencies (COPs), heat pumps and district heating networks could release 50% to 70% less carbon emissions than a gas boiler under the rather unlikely event that the future carbon intensity of electricity in the UK does not decrease and remains at around 290 gCO2e/kWh, as in 2018. Moreover, if the future carbon intensity of electricity in the UK continues to decline, under the less optimistic projection, if the future carbon intensity of electricity becomes 50% higher than BEIS projected, using heat pumps or district heating in place of gas boilers could reduce the carbon emissions from heat demand by at least around 70% alone. Whereas, if the future carbon intensity of electricity is 50% lower than projected, heat pumps and district heating could reduce carbon emissions by at least 90% while meeting the domestic heat demand.

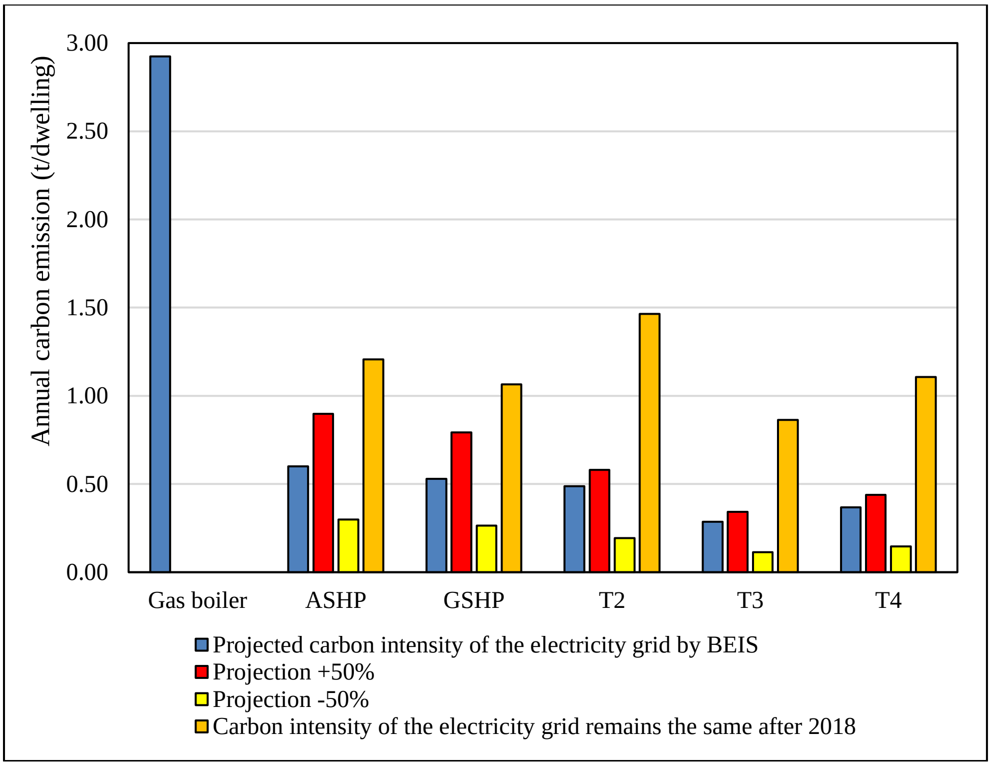

Figure 4.39: Modelled annual carbon emissions per dwelling from different heating options under four sets of the carbon intensity of electricity.

4.4.3.1.4 Uncertainties in district heating transport pipe layouts and heat loss, and costs

This study categorises three district heating topological configurations that can utilise heat pumps differently. However, this model does not differentiate the layouts of district heating pipes for district heating networks. District heating network layouts can affect the overall heat distribution losses, and they play an important role in the system economy (Nussbaumer and Thalmann, 2016). In practice, every district heating network needs to be treated on an individual basis when selecting the types, sizes, layouts and the levels of insulation of district heating pipes, based on many factors such as pipe costs, peak demand, operation strategies, the distance between dwellings and energy centres, locations and local planning conditions.

When a district heating network becomes more extensive, the design and installation of its transport pipes may become more complex, and multiple types and sizes of pipes can be used as transport pipes. This study investigates ‘hypothetical district heating networks’. It applies assumptions of district heating transport pipe lengths based on existing network examples or network routes proposed in district heating feasibility studies. The model compares their heat loss on different scales, but this study does not model the detailed layouts of the transport pipes. This imposes uncertainties regarding heat loss from transport pipes and the costs between different district heating networks.

To illustrate the impact of different network layouts on the overall system heat loss and costs, two example networks at the same scale but with different layouts are compared. Previously, in Section 4.3.2 (page 168), the Shoreditch heat network was selected to estimate the total length of transport pipes of a medium-scale district heating network (connecting 500 dwellings). The Shoreditch heat network serves 464 dwellings, and the network’s layout and transport route were mapped and measured using the London Heat Map (Centre for Sustainable Energy, 2021). As shown in Figure 4.40, this district heating network has a radial layout, and it was estimated that the total network transport route was 753 m, which is approximately 1.6 metres per dwelling.

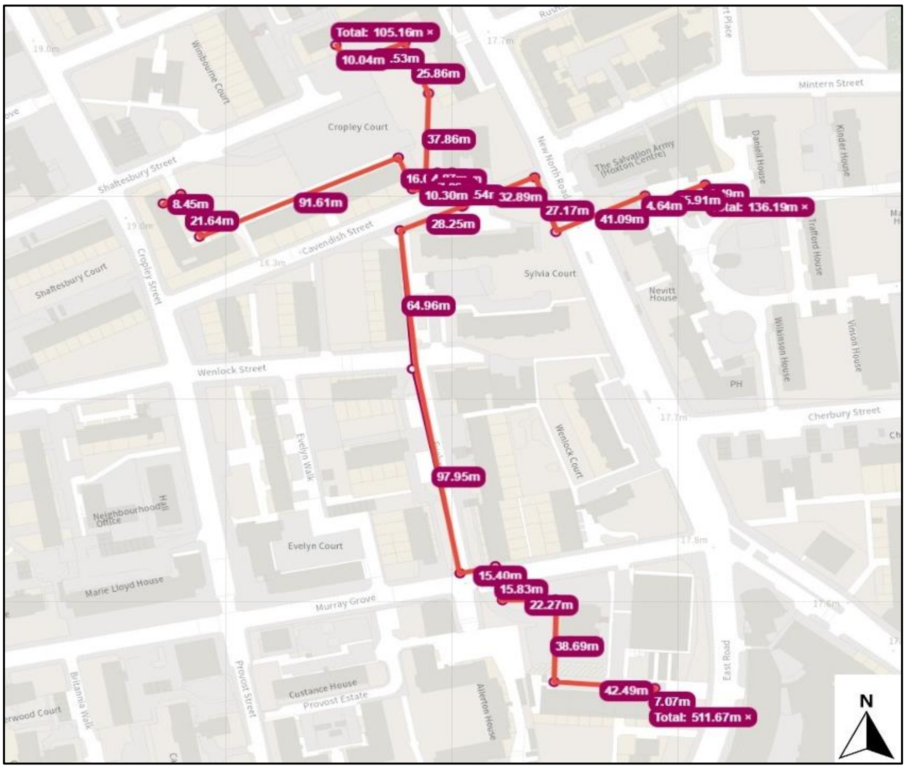

Figure 4.40: The network layout and mapped transport pipes of the Shoreditch heat network.

On the other hand, Figure 4.41 illustrates the network layout of the Hillingdon-Hayes heat network, which was identified as a network at the same scale as the Shoreditch heat network. The Hillingdon-Hayes heat network is located in the London borough of Hillingdon and connects to an energy centre that was converted from a former record factory. Its network route was mapped and measured using the same method. The Hillingdon-Hayes heat network has a linear layout as shown in Figure 4.41 and connects to 547 residential units (Vital Energi, 2013). According to the measurements, using the London Heat Map, the Hillingdon-Hayes heat network has a total of about 1,100 metres of transport route, which is about 2 metres per dwelling. To compare these two networks, the lengths of their transport pipes were proportionally adjusted, assuming that both networks were supplying heat to 500 dwellings.

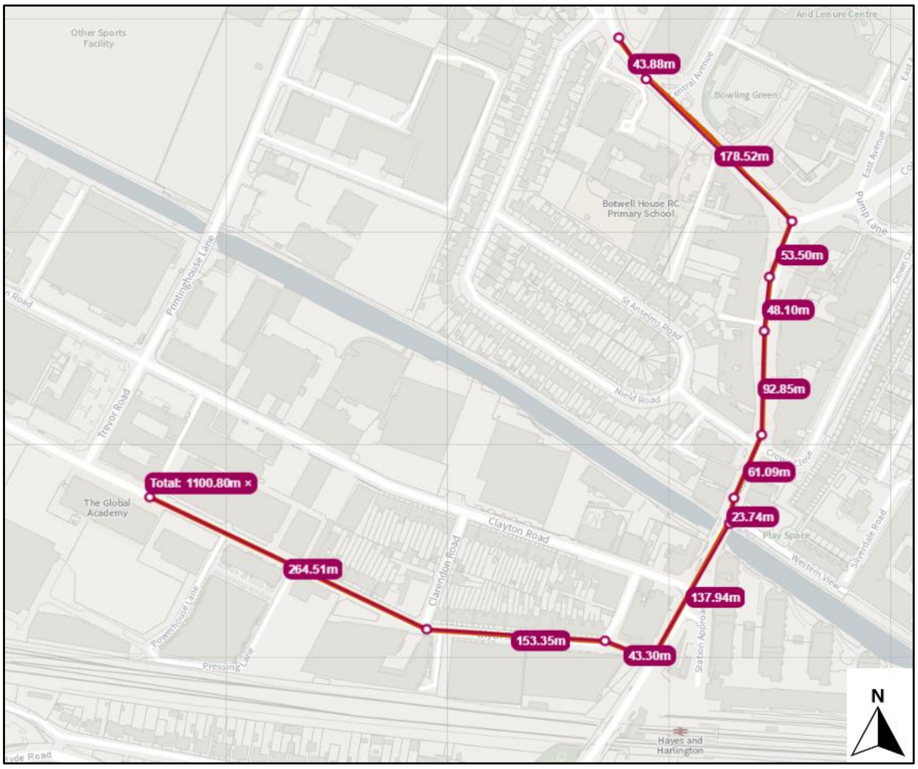

Figure 4.41: The network layout and mapped transport pipes of the Hillingdon-Hayes heat network.

Figure 4.42 compares the total annual heat loss from the transport pipes of a medium-scale district heating network when its transport pipe lengths are assumed to be adopted from the Shoreditch heat network (radial layout) or the Hillingdon-Hayes heat network (linear layout). Due to the relatively longer transport pipes per dwelling used in the Hillingdon-Hayes heat network, the overall annual heat loss from the transport pipes was higher. Based on the heat loss calculations (page 163), under the high-temperature network assumptions (Topology 2, with 80 ℃ flow temperature and 60 ℃ return temperature), the annual heat loss from transport pipes increased from 427 MWh to about 530 MWh, an increase of over 200 kWh per dwelling per year.

Moreover, under the low-temperature network assumptions (Topologies 3 and 4, with 30 ℃ flow temperature and ambient return temperature), the annual heat loss from transport pipes increased from 71 MWh to about 88 MWh – an increase of about 34 kWh per dwelling per year – if the assumptions on transport pipes were switched from the Shoreditch heat network to the Hillingdon-Hayes heat network. Therefore, even at the same district heating scale, different transport pipe layouts could lead to considerable changes in transport pipe length, distribution heat loss, and electricity consumption from heat pumps.

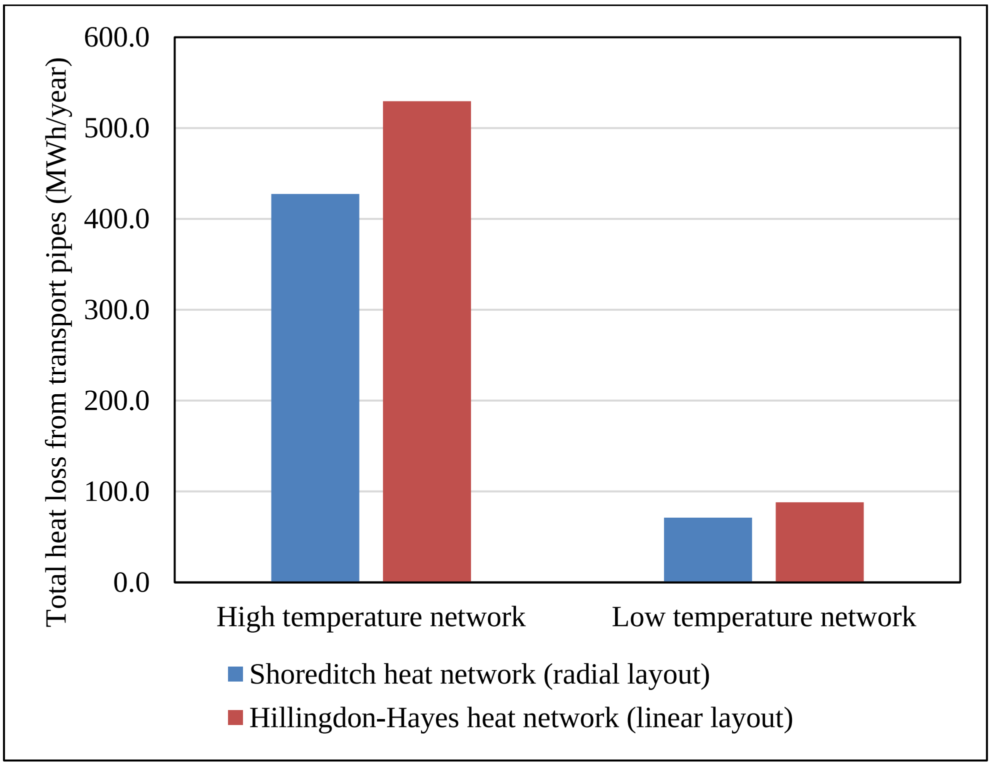

Figure 4.42: Total annual heat loss from transport pipes from two types of network layouts, assuming 500 dwellings.

Additionally, besides additional heat loss and electricity consumption from heat pumps to compensate for the extra heat loss, longer transport pipes also contribute to higher capital and installation costs. By switching transport pipe length assumptions from the Shoreditch heat network to the Hillingdon-Hayes heat network, the overall capital costs to install transport pipes could increase by 24%, and lead to increased levelised costs for all district heating topologies. To further assess the impact of uncertainties in transport pipe length, Section 4.4.3.2 (page 261) adjusts the transport pipe length (based on example heat networks) by ±50%, using the same method applied by the IEA, NEA and OECD (2015) to quantify their impact on the overall levelised costs and annual electricity consumption per dwelling.

This model assumes that two types of district heating pipes are used: transport pipes and service pipes. The model uses the average length of service pipes and assumes the total length of transport pipes based on the number of dwellings and mapped example networks (as shown in Table 4.2, page 173). This study assumes that additional tiers of transport pipes are utilised when the scale of district heating expands (detailed model assumptions are indicated in Tables 4.11 and 4.12, page 218). However, the lengths and sizes of intermediate tiers of pipes may differ according to a mixture of factors such as aggregated demand, width and geometry of dwellings and space between them. This can be a very complicated issue depending on the locations and the layouts of district heating networks. Hence, for large heat networks, the design and installation of different tiers of district heating transport pipes may vary significantly in reality.

Furthermore, when a district heating network expands, the network may add extra branches with extra pipes to connect the distribution network to buildings. Also, it is common to add extra consumers and extra transport pipes to the main transport systems over time. Therefore, additional heat loss and pumping energy are associated with these additional branches. Hence, additional electricity could be needed to compensate for the extra heat loss and pumping energy, and these extra branching pipes could add more capital costs to the overall district heating system.

Therefore, there are significant uncertainties in costs and heat loss from transport pipes according to district heating network designs and installations. Additional transport and service pipes are used when the scale of a district heating network grows, and the overall lengths of service pipes could be significantly longer than the overall lengths of the transport pipes when the network becomes large and complex. When the size of a district heating network grows, heat loss from transport pipes may contribute to a smaller proportion of the overall distribution heat loss than heat loss from service pipes. For example, DECC and AECOM (2015) assessed the existing district heating networks in the UK and stated that internal service pipe lengths could be ten times greater than the transport pipe lengths of networks, and this results in high potential heat loss and construction costs. Furthermore, large-scale district heating systems may utilise large transport pipes with higher heat loss (w/m). The overall heat loss from transport pipes may grow intensively if the total length of transport pipes rises significantly.

Additionally, this study assumes a common network design that two pipes are required for the network: flow and return pipes. The design and technical performance of district heating pipes have been improving due to a significant amount of scientific research and industrial experience. There is a tendency to utilise more reliable and durable pipes, as well as flexible designs, in modern district heating networks. For example, district heating networks utilising twin pipes that could contain both flow and return pipes within the same pre-insulated pipe. In practice, the selections of pipes and their lengths need to be assessed thoroughly on an individual basis, because they may lead to significant variations in distribution heat loss and capital costs to construct the networks (Dalla Rosa et al., 2011). Thus, the layouts, types and sizes of transport pipes need to be carefully evaluated to minimise their lengths, reduce heat loss per dwelling and save capital and operational costs.

4.4.3.2 Global sensitivity analysis of multiple model input parameters and relative importance of different technical and economic parameters

The techno-economic model developed in this study comprises a number of assumptions and input parameters for district heating networks that may interact with each other and vary over time, and consequently affect the technical performance of the heating technologies and their costs. To investigate these variables, sensitivity analyses are conducted by means of Monte Carlo simulations. These offer insight into and an understanding of the district heating parameters that need more attention and those that may improve system efficiencies, reduce heat loss, and reduce overall costs when comparing the different topological configurations to utilise heat pumps and district heating networks.

By means of Palisade Decision Tools, the model inputs are treated as uncertain and are altered within their upper and lower bounds. Assumptions and results of large district heating networks (with 1,500 dwellings) are treated as reference values. In order to determine the upper and lower bounds of each model input assumption, an arbitrary range within a ±50% change from the baseline values, except for the discount rates, which are adjusted between 1% and 10%, similar to the local sensitivity analysis. All inputs are modelled with uniform distribution for the Monte Carlo simulations, which follow the 'principle of indifference' (Keynes, 1921; Li, 2013). This is due to the long length of the technology's lifetime (50 years for district heating networks).

Monte Carlo simulations are performed for different topological configurations for the integration of heat pumps and district heating networks. The model inputs are resampled by the Latin Hypercube method to recalculate one possible outcome of the LCOH for the different heating options, and this process is reiterated 50,000 times to identify possible outcomes and which model inputs have the most significant impact on the overall LCOH. Tornado graphs are created to enable the visualisation of changes in different parameters' impact on the overall LCOH and total electricity consumptions for different district heating topological configurations. Furthermore, besides the tornado graphs, the box and whisker plots illustrate the variance of the model outcomes and indicate the potential median, lower and upper quartiles of the final LCOH or electricity consumption per dwelling, when the underlying input assumptions or parameters are changed. The results are illustrated in Figures 4.43 to 4.50.

The first three tornado graphs in Figures 4.43 to 4.45 indicate the relative importance of different technical and economic parameters to the overall LCOH, and how sensitive the model results are to these parameters, for three topological configurations to connect district heating networks, dwellings and heat pumps. Due to a large amount of input data and parameters in the model, these tornado graphs only show the top 15 parameters which could affect the LCOH.

As the tornado graphs display, besides the discount rate, which could significantly affect the overall net present value as evaluated previously in the local sensitivity analysis (page 244), heat demand and heat pump COP are ranked as the three most important factors among all model inputs and assumptions that may affect the overall LCOH for different district heating topological configurations. For Topology 2 (i.e. high temperature networks with centralised large heat pumps), the COP of central heat pumps is ranked the most crucial input because it can directly determine the overall electricity consumption and system efficiency. Similarly, for Topologies 3 and 4, the LCOH results are more sensitive to the COP of booster heat pumps or the large heat pumps than other components considered in the district heating networks. Moreover, the box and whisker plots in Figure 4.46 indicate the overall LCOH distributions through their medians, upper and lower quartiles, and interquartile ranges for different topologies to utilise heat pumps in district heating, when the input data are altered during the Monte Carlo simulations. The ends of the whiskers are set at 1.5 times of the interquartile ranges above or below the upper or lower quartiles.

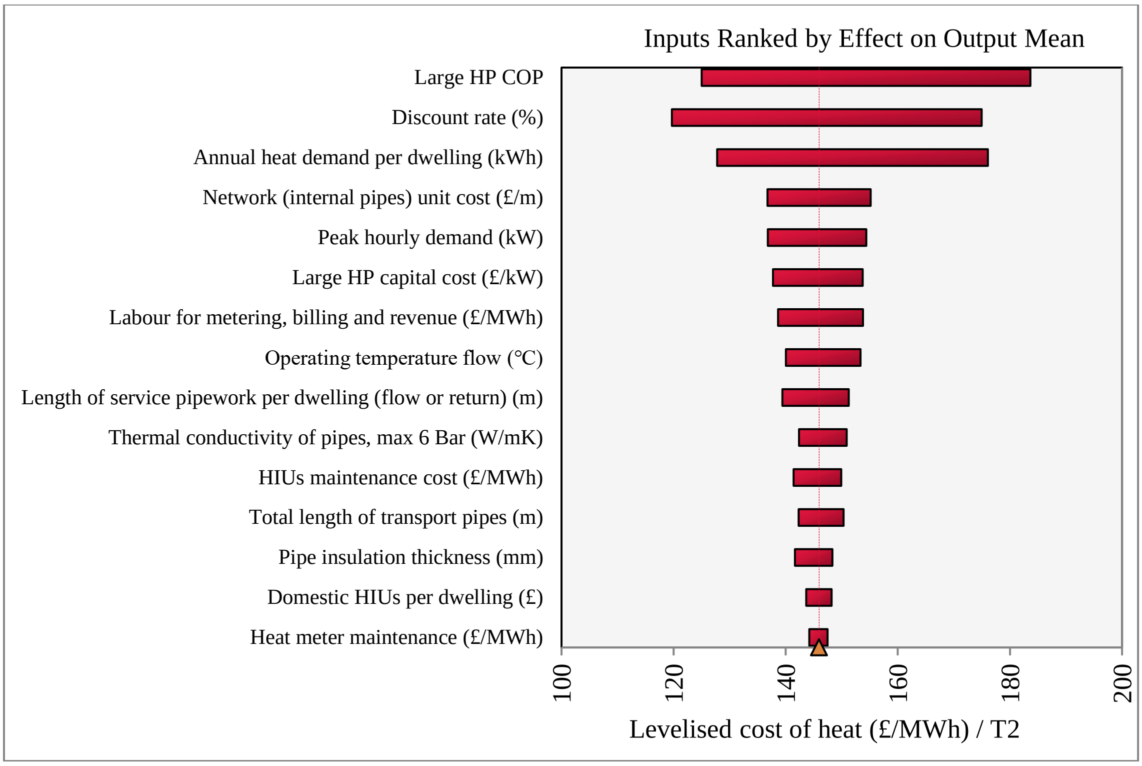

Figure 4.43: Tornado graphs of the LCOH for Topology 2.

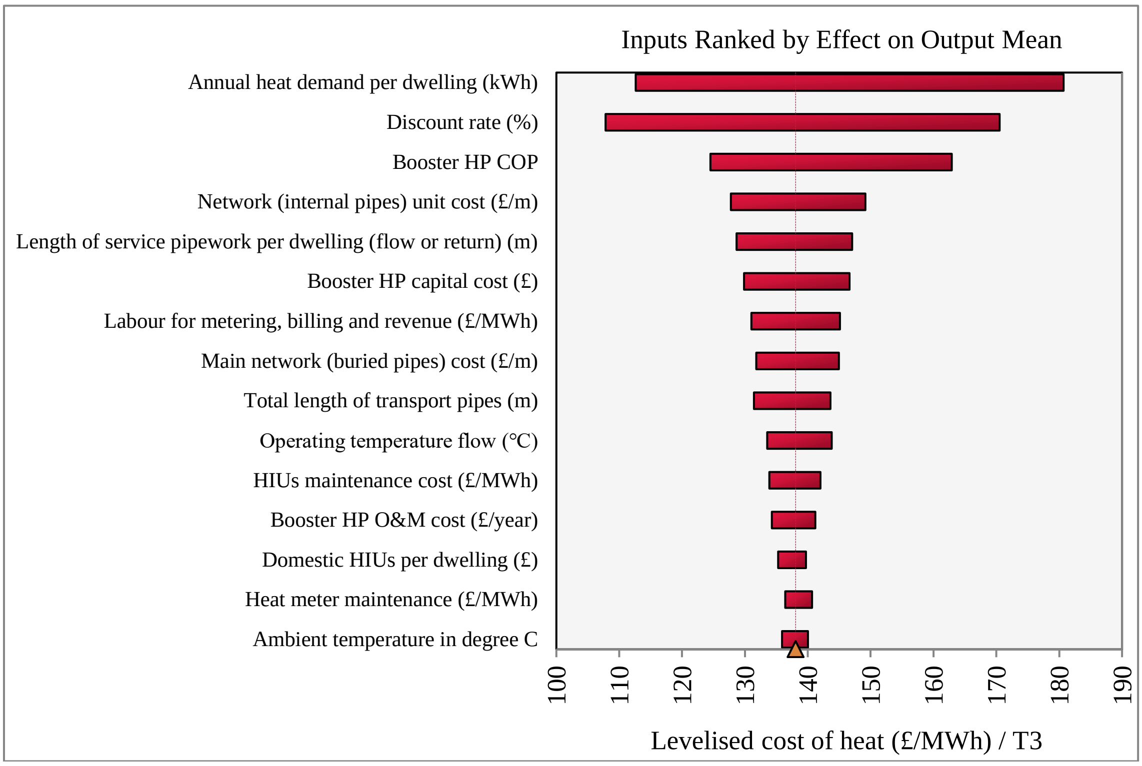

Figure 4.44: Tornado graphs of the LCOH for Topology 3.

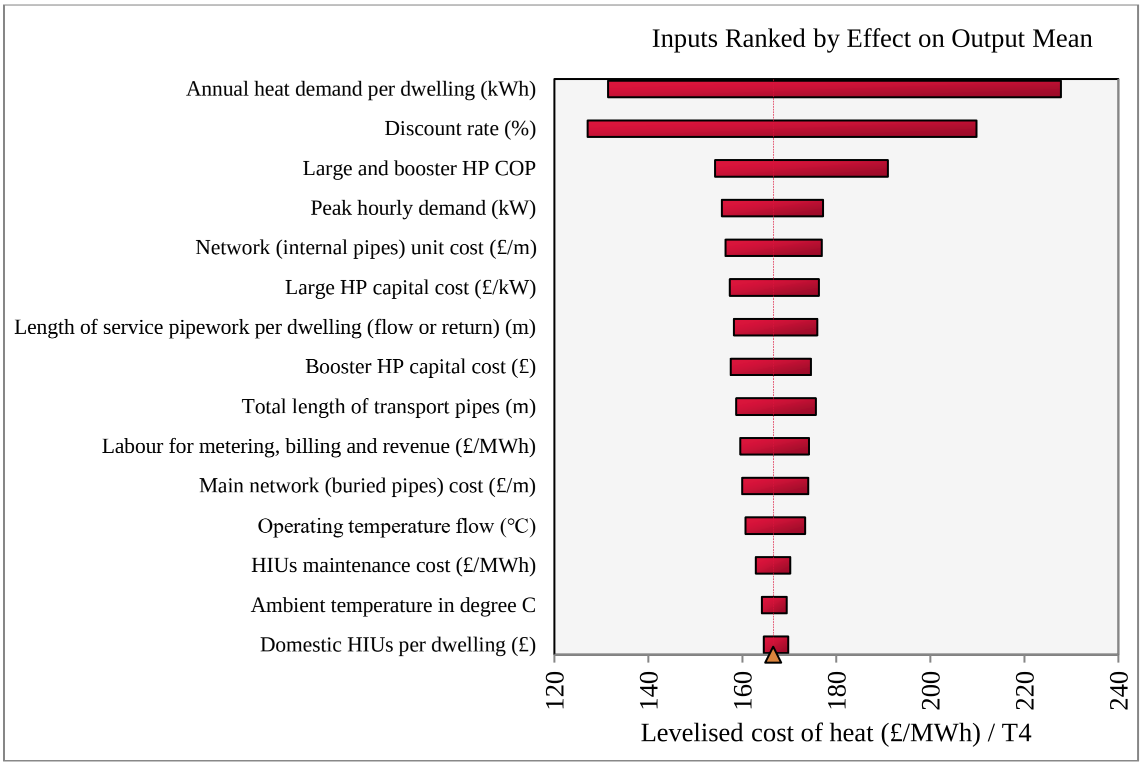

Figure 4.45: Tornado graphs of the LCOH for Topology 4.

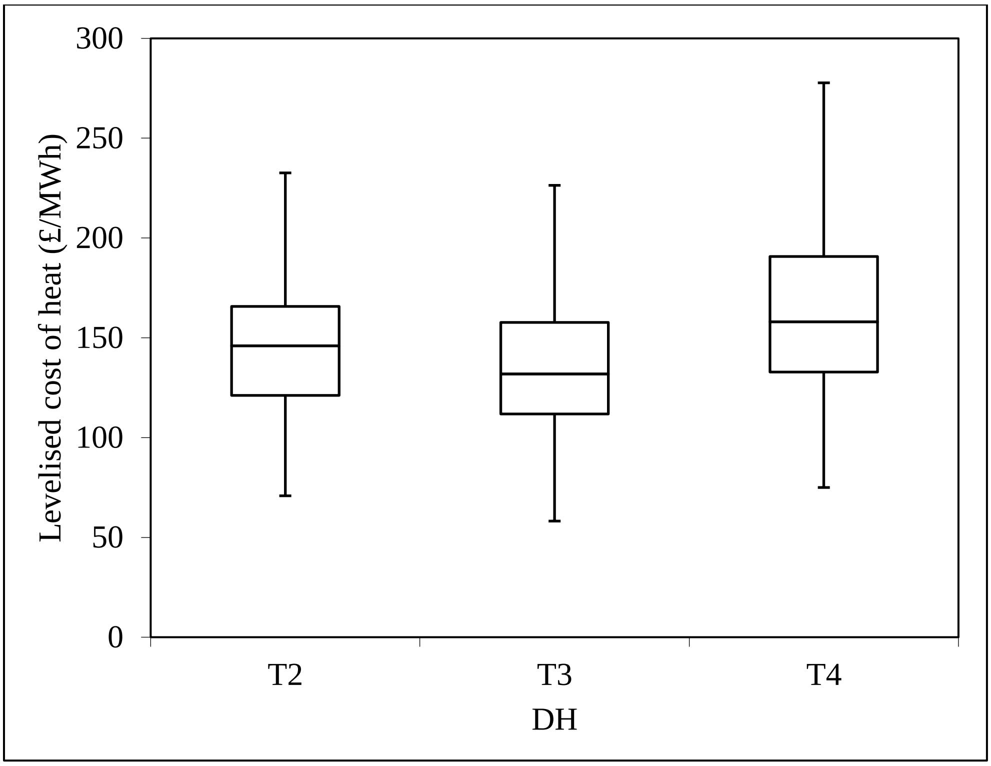

Figure 4.46: Box and whisker plots of the LCOH for different topologies to utilise heat pumps in district heating networks.

The three tornado graphs in Figures 4.47 to 4.49 display how changes in model parameters affect the overall electricity consumption of district heating systems. Heat pumps COP and heat demand are the two most important input factors. As indicated in these three figures large heat pump COP and small booster heat pump COP are the most important inputs that could affect the overall electricity consumption of district heating networks. Therefore, ensuring heat pumps to operate at high COP is the most effective way to minimise the overall electricity consumption of the whole system, hence, to reduce electricity costs and improve the overall system efficiency.

Moreover, the box and whisker plots in Figure 4.50 indicate the potential result distributions of the average annual electricity consumption per dwelling for different topologies to utilise heat pumps in district heating networks. The figure indicates potential outcomes when the input data are altered during the Monte Carlo simulations, including medians, upper and lower quartiles, and interquartile ranges. Additionally, the detailed model inputs and their variations (upper and lower bounds) for Monte Carlo simulations are presented in Appendix D, together with probability density diagrams of the potential outcomes of the LCOH or electricity consumption per dwelling for different topologies, when the simulations are reiterated 50,000 times for each of the results.

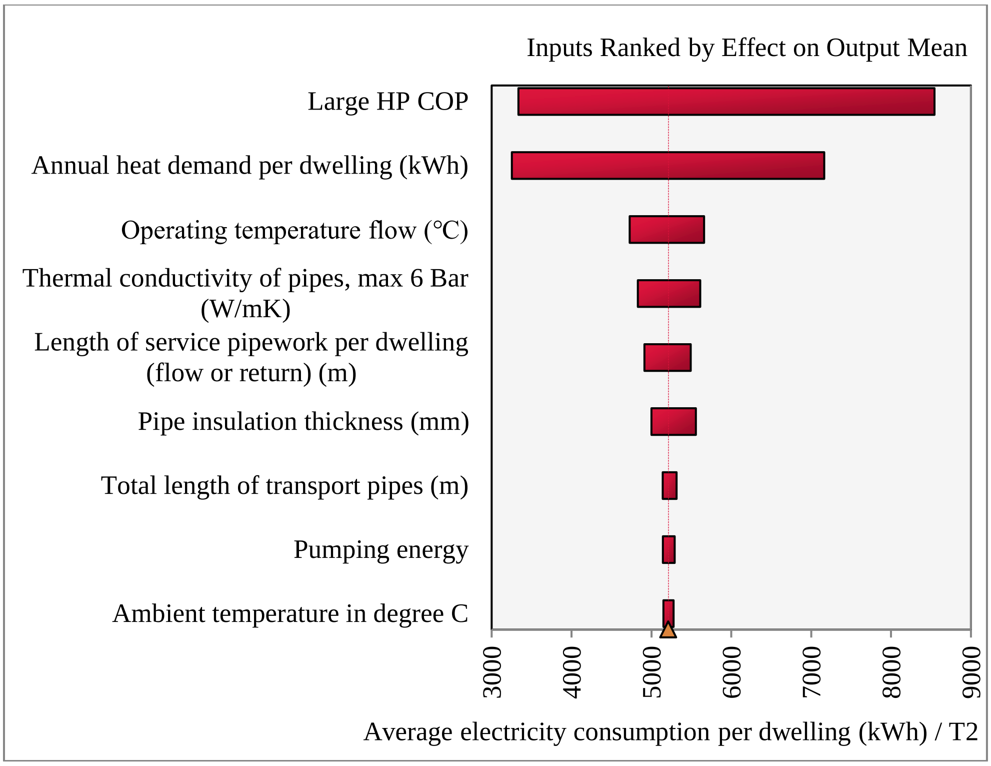

Figure 4.47: Tornado graphs of the average annual electricity consumption per dwelling for Topology 2.

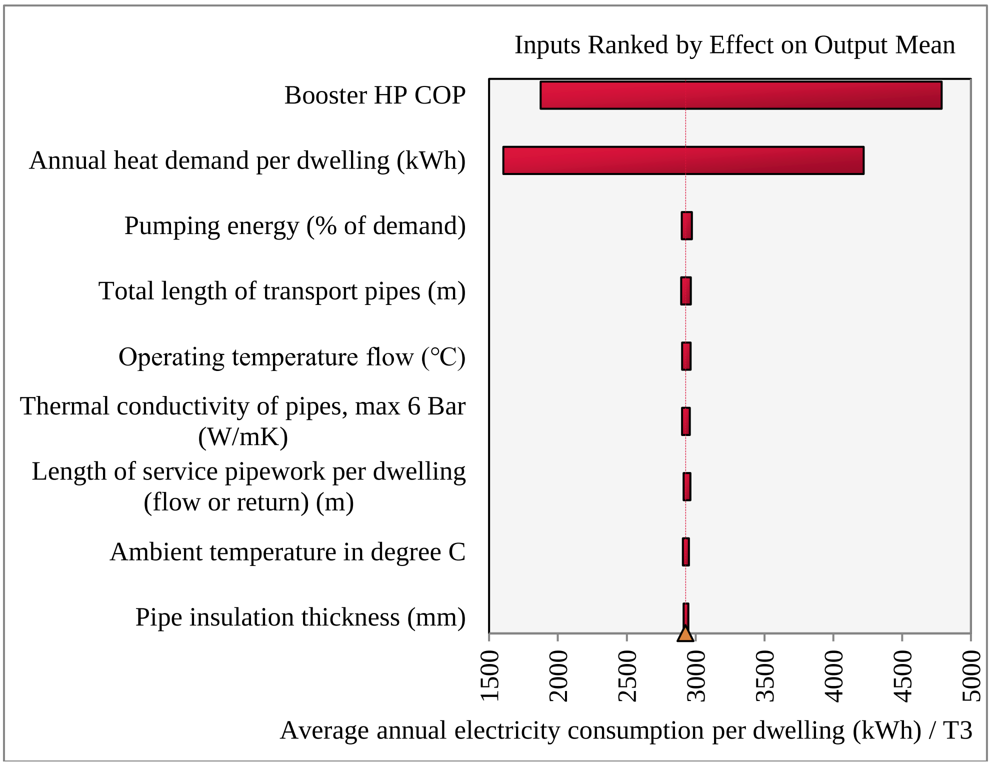

Figure 4.48: Tornado graphs of the average annual electricity consumption per dwelling for Topology 3

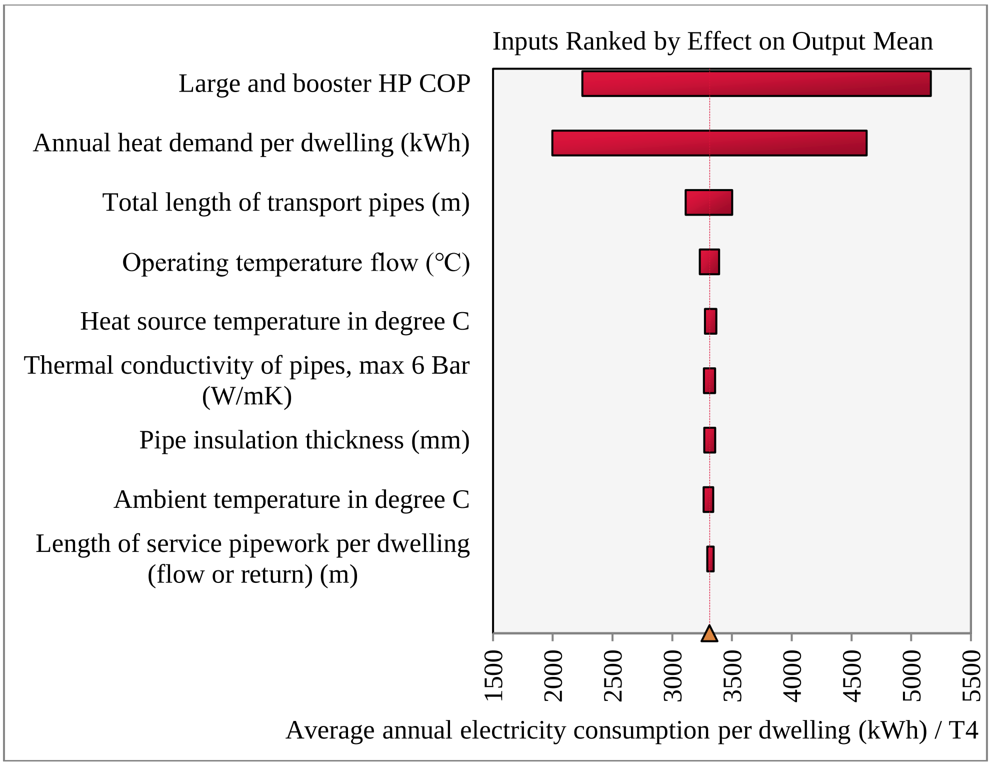

Figure 4.49: Tornado graphs of the average annual electricity consumption per dwelling for Topology 4.

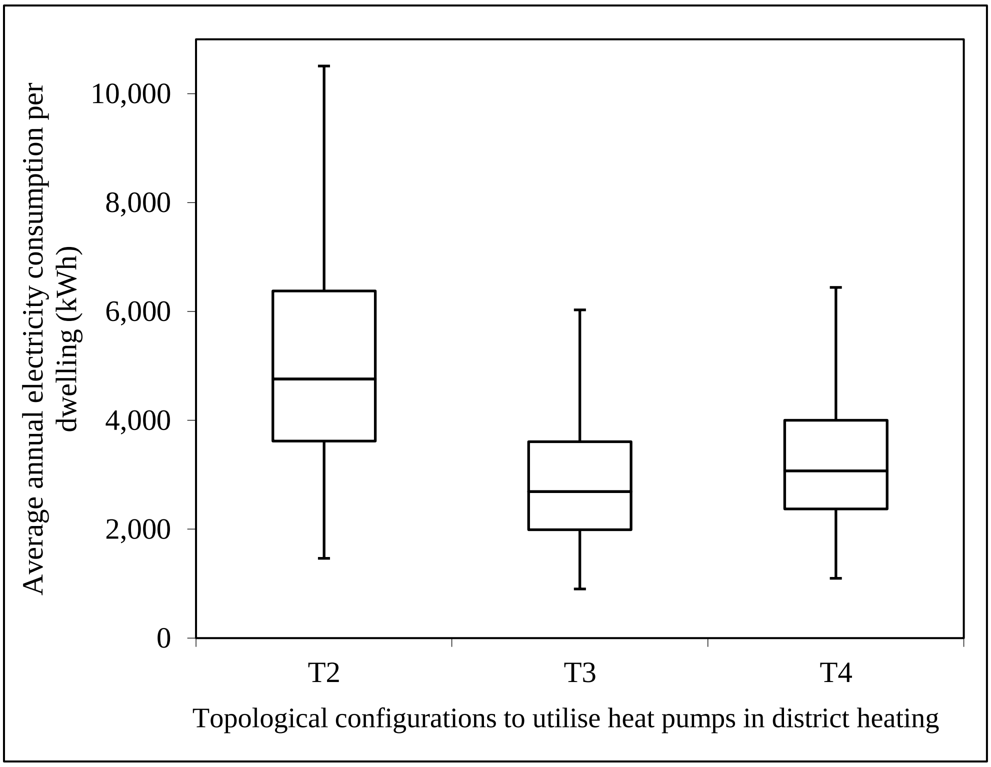

Figure 4.50: Box and whisker plots of the average annual electricity consumption per dwelling of different topologies to utilise heat pumps in district heating networks.

Chapter 5: Conclusions

The UK's energy and climate objectives have set ambitious targets to reduce carbon emissions through a series of carbon budgets. Meanwhile, many policy incentives have been introduced to secure sustainable energy supplies and improve energy affordability for households. Domestic heating is one of the most important compositions of energy consumption in the UK. It is the main source of carbon emissions from dwellings because the majority of current domestic heating is supplied through the combustion of natural gas.

The domestic heating system in the UK has experienced fundamental changes over the past century, yet it still needs significant transformations to meet future energy and climate objectives. The well-developed natural gas networks and cheap natural gas are the most substantial challenges for the future deployment of low-carbon heat technologies. To achieve the government's energy and environmental targets, it is imperative to understand domestic heat demand and study the potential heating options to replace the conventional gas-fired system and reduce carbon emissions.

Electric heat pumps with decarbonised electricity, together with district heating networks that utilise energy that would otherwise be wasted, can play vital roles in decarbonising the UK's residential heating sector. Over the past few decades, heat pumps and district heating have been established technologies with large scale deployment in many European countries. However, their markets, supply chains and regulatory framework are immature in the UK, and heat pumps and district heating networks have to become cost-competitive in order to achieve mass deployment in the UK.

This chapter draws on key results and insights from domestic energy demand analysis and heat pumps and district heating techno-economic modelling of this research. This chapter concludes the main results of this study, reflects on the limitations of the modelling approaches, and indicates the contributions of this research, together with outlining some unanswered questions and giving some ideas for potential future studies.

5.1 Empirical analysis of domestic energy demand

A thorough understanding of energy consumption in dwellings is fundamental to assess potential alternative heating technologies and thereby replace the existing fossil fuel-fired heating systems. Domestic energy load profile studies help to quantify and understand how energy is consumed in residential buildings and design and evaluate low-carbon energy supplies and peak demand management strategies. Energy load profiles have many applications, but there have been fewer empirical studies than modelling studies because empirical domestic energy consumption data at high temporal resolutions on large scales can be challenging to access due to technical, ownership and privacy concerns. This research presents an empirical analysis of domestic energy demand and diversity using actual end-users' energy consumption data collected from the largest smart meter field trial, which included one of the coldest recent years in Britain, together with monitored data from domestic heat pump field trials.

Half-hourly smart meter data from more than 18,000 dwellings across Britain were employed to construct gas and electricity load profiles over one year, based on a range of temporal sampling frequencies, to scrutinise peak energy consumption. This study has found that the most suitable timescale on which to analyse residential energy consumption is hourly, with respect to the availability of external air temperatures on a large scale. Based on detailed metadata from a subset of over 1,800 dwellings, this study has quantified annual electricity and gas consumption in different types and ages of dwellings in the UK and investigated aggregated hourly energy loads versus external air temperatures, together with a further analysis of winter peak energy demand under cold weather conditions.

The smart meter data analysis indicates that the annual gas consumption for the dwellings was about four times higher than the electricity consumption, while the peak hourly gas-to-electricity consumption ratio was around seven on the coldest days. The gas load profiles displayed two distinct peaks, which were caused by demands for space heating and domestic hot water in the mornings and evenings in the context of widespread intermittent heating. Furthermore, a correlation between domestic energy consumption in response to changes in external temperatures has been quantified through a linear regression analysis, and peak electricity and gas consumption has been identified during winter cold spells. The diversity effect in energy consumption among dwellings has been discussed with quantitative illustrations regarding how the diversified peak energy demand changes and stabilises when the number of dwellings connected in one system changes. Results show that diversity reduced gas and electricity maximum demand per dwelling by up to 33% and 47%, respectively.

This research also discusses the external temperature and time of day at which the aggregated peak demand occurs, as a function of the number of aggregated connected dwellings. The ADMD curves for both gas and electricity show qualitatively similar asymptotic behaviour, but with significant quantitative differences. The evidence suggests that peak electricity consumption is more diverse than peak gas consumption; while the diversity effect may reduce the aggregated ADMD per dwelling, it does not significantly affect the time when the aggregated peaks occur.

Additionally, by comparing daily load profiles between gas boilers and electric heat pumps, this study has established that both normalised profiles show strong seasonality features over the course of a year. Nevertheless, under hourly resolution, the results suggest that electric heat pumps may operate differently from gas boilers because electric heat pumps tend to operate more continuously. In contrast, the electricity load profiles from heat pumps were less peaky than the gas load profiles from boilers.

This empirical quantitative analysis of energy loads and demand diversity has utilised a large sample of smart meter data from the UK. The results from this analysis provide an empirical basis to build a techno-economic model for heat pumps and district heating networks and thereby address the second subsidiary research question proposed by this thesis, to evaluate the economic and environmental trade-offs by utilising heat pumps and district heating networks according to various topological configurations.

5.2 Techno-economic modelling of heat pumps and district heating networks

Heat pumps can be installed at individual dwellings or integrated into district heating networks according to different scales. This research investigated the technical, economic, and environmental trade-offs among different approaches to utilising heat pumps and district heating networks compared to dwellings that are heated by individual gas boilers. A techno-economic model has been built to appraise the technologies' performance, the LCOH for different heating options, and their potential for reducing carbon emissions compared to gas boilers, using empirical energy demand data. This study proposed four different topological configurations to connect heat pumps, dwellings, and district heating networks on five defined scales based on the number of connected dwellings.

The model considered aggregated heat demand and the diversity effect at five different scales in order to size the peak generation capacities and select appropriate district heating pipes. Besides the annual gas and electricity prices projected by the government, this model also included historical hourly wholesale and retail electricity prices over a year. It modelled the trade-offs between heat pumps' COP and operating temperatures, pipe sizes, heat loss, and pumping energy for different topological configurations and calculated the hourly aggregated heat demand, heat generation, and electricity consumption over a year. It then computed the initial capital costs, O&M costs, gas or electricity costs, levelised cost of heat, and carbon emissions for different heating technologies over their lifetime.

The technical performance and cost of heat pumps and district heating may vary according to a mixture of factors, including heat demand, operating strategies, and network design strategies. To move away from gas heated domestic heating systems, installing individual air source heat pumps or booster heat pumps (Topology 3) to utilise district heating and available heat sources are more cost-competitive than installing individual ground source heat pumps or utilising large heat pumps in heat networks (Topologies 2 and 4).

At the individual scale, the LCOH is lower in dwellings with higher heat demand. Owing to high heat pump capital costs and electricity prices, the overall LCOH for a ground source heat pump could be over 35% more expensive than an individual gas boiler. Nevertheless, heat pumps may reduce an individual household's carbon emissions from heating by up to 80% due to high efficiency and the low projected carbon intensity of electricity.

At the district scale, the cheapest way to meet heat demand is to utilise individual booster heat pumps that connect to low temperature district heating networks to utilise low temperature heat sources (Topology 3). Also, under the same electricity pricing scheme, Topology 3 has the lowest annual electricity cost per dwelling among all the heating options. The average annual electricity cost of a gas boiler is over 30% more expensive than the annual fuel cost of Topology 3. On the other hand, when there is no available free heat source, Topology 4 (dwellings with individual booster heat pumps and connected to low temperature district heating networks with centralised large heat pumps) is the most expensive way to supply heat due to its high capital costs.

Although using centralised large heat pumps in high temperature networks may cause higher heat loss and electricity consumption, Topology 2 has lower overall LCOH and initial investment cost per dwelling than individual ground source heat pumps and Topology 4 when there is no local free heat source. Moreover, utilising heat pumps and district heating could reduce carbon emissions from heating by up to 90% in comparison with meeting heat demand by individual gas boilers, if the carbon intensity of the electricity grid keeps declining as projected.

Among a range of technical parameters of heat pumps and district heating networks, the operational temperatures, and the COPs of heat pumps are the most crucial factors which could affect the overall system efficiency, fuel consumption, carbon emissions, and costs. This study also discussed the trade-offs between operational temperatures, costs, heat loss, and pumping energy among different district heating pipes, as well as the impact of oversizing versus undersizing district heating pipes.

Through cost data from the domestic RHI scheme, this study demonstrates that the capital cost of heat pumps decreases when the size of heat pumps increases, as an indication of economies of scale. Furthermore, when comparing district heating networks at different scales, although larger district heating networks may have higher distribution and transmission heat loss and pipe costs, the average heat loss per dwelling decreases when the scale of a district heating network gets larger. When the scale of a district heating network expands, the unit cost of heat and the average cost per dwelling to install the heating system declines.

Although more extensive and longer pipes are used in larger district heating networks, and their associated heat loss increases, the overall heat loss as the percentage of total heat generation drops because the overall heat demand from dwellings increases at a much higher rate. Additionally, as the selection and layout of district heating pipes may significantly affect the distribution and transmission heat loss and networks' capital costs, it is crucial to carefully evaluate the design and installation of district heating pipes to avoid oversizing and minimise heat loss and capital costs based on individual networks' characteristics.

Using individual heat pumps or heat pumps with district heating networks to meet domestic heat demand is more expensive than using individual gas boilers; nevertheless, a large proportion of the overall cost is spent on capital and O&M costs, which may contribute to local constructions and promote employment. Additionally, if the district heating topological configurations were able to adopt wholesale electricity prices at district scales, the LCOH and electricity costs to operate district heating with heat pumps could become cheaper than individual air source or ground source heat pumps.

Heat pumps and district heating networks could substantially reduce carbon emissions but may also increase the cost of heat significantly if there are no economical and environmentally sustainable heat sources. The integration of heat pumps, decarbonised electricity, low temperature district heating networks, and local sustainable heat sources could play an economic and sustainable role to move away from fossil fuel based heating systems, decarbonise domestic heating, and meet demand.

5.3 Contributions of this research

A comprehensive knowledge of domestic heat demand and peak demand is essential for efficient and reliable heating system designs and deployment. This research delivers an empirical investigation of residential energy demand heterogeneity by analysing high-resolution smart meter data from the largest smart meter field trial in the UK, including one of the coldest years over the last three decades. The methods used in this study are also useful for countries or areas that experience cold winters as beneficial approaches to quantify energy consumption, better understand energy load profiles and manage peak demand. The analysis of energy demand diversity offers an insight that can improve district energy networks operations to size energy generation and distribution infrastructures' capacities appropriately, ensure energy infrastructure reliability, and reduce costs through economies of scale. It provides direct contributions to the fields of district energy development, energy demand research and energy market management strategies based on empirical evidence.

Electric heat pumps, district heating networks and decarbonised electricity can contribute to the deep decarbonisation of the UK's domestic heating sector. The deployment of heat pumps and district heating networks on large scales will require intensive investments, alterations in supply chain practices and public acceptance. There are abundant studies on heat pumps and district heating in some European countries, and many of the results of this study are not new in that context. Nevertheless, the techno-economic model and its results from this research provide a foundation to evaluate the comparative economic and environmental advantages of utilising heat pumps and district heating on different scales in a UK context. It contributes to local energy infrastructure planning on different scales and informs long-term energy strategies to decarbonise the domestic heating sector. It can also assist manufacturers and utility suppliers in evaluating heat pumps and district heating investments, designing contracts and tariffs, and regulating energy generation and purchasing.

5.4 Critique of the levelised cost method and reflections on the techno-economic model

In this research, a techno-economic model based on the levelised cost method is developed to conduct economic assessments of different potential approaches to the use of electric heat pumps and district heating networks to meet the domestic heat demand compared to individual gas boilers. The levelised cost of energy is a valuable instrument for assessing the costing structures of different energy-generating technologies. Nevertheless, this method and the techno-economic model developed in this research do have their limitations. It is an idealised setup, abstracted from real situations, to estimate the cost of heat and emissions from different topological configurations to utilise heat pumps and district heating networks. Besides, some subjects that are worth investigating were not examined in this techno-economic model.

This study investigates the levelised costs and initial investment costs of meeting the heat demand. However, it does not reflect on the price of selling heat or the price paid by households. The cost of heat (£/MWh) is an output of the techno-economic model, and the levelised cost of heat is a unit cost of heat throughout the lifespan of the different heat pumps and district heating technologies. It is not the price of selling heat produced by heat pumps or district heating operators. Thus, the levelised method does not reflect the short-term or long-term volatilities of energy prices, and the results of this model do not represent the price paid by individual customers. Correspondingly, the modelled initial investment costs of installing heat pumps and district heating networks are not necessarily the prices paid by individual households.

The outputs of the levelised cost model are highly sensitive to the input data and assumptions. Consequently, variations in model inputs, especially the technologies' cost data and technical performance, could substantially alter the model's results, as revealed by the uncertainty and sensitivity analyses. In order to develop a model and compare different heat pumps and district heating topological configurations, the costs and technical data used in this study were collected from different sources before technology modelling and economic evaluations. However, the costs and technical performance of these technologies could be different depending on numerous factors, including how the heat pumps and the subsystems of district heating networks are installed and operated.

Because the technologies' costs are commonly considered commercially sensitive, obtaining a set of standardised cost data for heat pumps and the components of district heating networks from publicly available sources is challenging. For example, due to a lack of available data, the technical data and cost data for the district heating pipes utilised in this model were collected from foreign district heating pipe manufacturers (Brugg and Logster) and engineering consultancy companies (Ramboll) instead of suppliers from the UK.

Moreover, this study models heat pumps' efficiencies (COP) and the performance of district heating components based on their operational conditions, and the model assumes that the technologies perform according to their designed standards or parameterised assumptions over their lifetime. The model simplifies this complex issue. How heat pumps and district heating networks are operated may change over time, with possible more dwellings, different heat sources or types of heat pumps added to the networks. Also, there are performance gaps between designed or modelled technology performance and how they function in real-life situations. For example, heat pump field trials in the UK have exhibited that heat pump underperformance is a common problem that can be caused by a mixture of factors (EST, 2013; Summerfield et al., 2016).

Furthermore, the levelised cost method compares the discounted lifetime costs between alternative technologies at the plant level (Aldersey-Williams and Rubert, 2019). However, this method does not represent all externalities and indirect costs, such as environmental and social impacts, network development, land costs, energy system balancing and management costs. For example, this study assumes that the carbon intensity of the electricity grid will keep decreasing over the next few decades. However, it does not consider the cost to decarbonise the electricity grid, or the upstream cost of gas supply systems. Also, the future deployment of electric heat pumps could lead to amplified peak electricity demand; consequently, extra costs could be incurred in order to upgrade the electricity network and to manage its peak. Besides, costs to purchase or rent the land or space to install heat pumps or district heating can vary enormously depending on the location. Hence, the levelised method and this research can be improved by taking into consideration of a broader range of economic, social and environmental externalities beyond the plant level.

The levelised cost method represents a one-time decision that lasts for an extended period of time as the technical lifetime of district heating networks can last for decades. The discount rate may play an important role in quantifying the discounted lifetime costs. Also, evaluating uncertain factors and their impacts on costs in the long term is challenging, and this model does not take into account future events that are hard to quantify, such as unanticipated events that could damage heating technologies, future taxes and subsidies, changes in exchange rates and technology innovations. This model adopts the projected natural gas and electricity prices and carbon intensities, which could be significantly affected by future energy and environmental policies.

Changes in these parameters could have a distinct impact on the overall costs and carbon emissions, as discussed in the sensitivity analyses. For example, this model used projected carbon prices by the government, but the level of carbon price may increase expressively with future energy and environmental policies and decarbonisation strategies to reach the Net-Zero emission targets. Moreover, this model could be expanded by including different installation years and taking into account potential future cost reductions and technology improvements. It could also be further developed by exploring scenarios that consider a range of potential future policy changes.

The techno-economic model developed in this study is based on the empirical heat demand from smart meter data analyses. This model does not explore future heat demand changes, as there is high uncertainty about the future domestic heat demand and the peak heat demand as it depends on numerous features, such as changes in local climate, building characteristics, and occupants' behaviours.

In addition, this study explores options for utilising heat pumps and district heating networks to meet the domestic heat demand compared to individual gas boilers. It does not consider other competing low-carbon heat options that can be deployed in the UK to reduce carbon emissions from domestic heating, such as (low-carbon) hydrogen, biomass heating, and solar thermal systems. This techno-economic model could be further developed beyond its current modelling boundaries to investigate additional low-carbon heating options at different scales and to explore their cost competitiveness.

5.5 Potential further research

Subject to funding and resources, there are several directions for potential further research as a logical progression of this research, for example:

- **Further refinement of energy demand data and their analysis**

The roll-out of smart meters in recent years offers an opportunity to study domestic energy demand. This study uses gas consumption data as a proxy to study heat demand. Due to data availability, this study did not differentiate heat demand for different purposes. A further study could gather data monitored by heat meters in operating district heating networks, analyse the differences in the load profiles of space heating and domestic hot water consumption, and explore how these load profiles may differ at the aggregated level with a higher temporal resolution. A refined heat demand analysis could support better design and control of district heating networks and potentially reduce the costs to construct and operate the system.

Also, this research categorised households based on their dwelling types and ages. There are different ways to classify households and their energy demand. Further research could explore households' heat demand based on a number of features, such as demographics, level of dwelling insulations, floor areas, and locations. A better understanding of households' energy demand could offer a better evaluation of potential low-carbon heat technologies. Moreover, this study explored time-series energy demand diversity. A further study could benefit from analysing demand diversity at the frequency domain and its applications on district heating generation and storage systems, to offer insights into flexible and economical operations of district heating systems.

This study only considered domestic energy demand. However, in reality, it is common to have district heating networks that connect both domestic and non-domestic buildings. Energy consumption from non-domestic buildings could be more diverse than domestic buildings. Energy load profiles from non-domestic buildings could show different peaks and troughs from domestic energy load profiles. A further study could benefit from examining how the aggregated load profiles could be affected by the addition of non-domestic buildings into district heating networks.

- **Investigation of features beyond the modelling boundaries and further exploration of district heating topological configurations and layouts**

Traditionally, district heating has strong links to electricity and gas networks via combined heat and power systems. District heating networks with heat pumps have the potential to integrate with renewable resources and storage systems to offer higher reliability and flexibility while electrifying and decarbonising the heating sector. An advantage of district heating is that it could utilise multiple resources, including fossil fuels and renewable resources or waste energy. District heating systems typically have multiple means of generating heat, thus increasing flexibility compared with heating technologies at individual scales. Furthermore, district heating also allows the utilisation and integration of renewable energy and waste heat with less impact at the level of individual dwellings. With limited commercialised examples in the UK, the utilisation and integration of renewable energy and waste heat into district heating networks are worth investigating.

This study compares costs and emissions of four topologies to utilise heat pumps and district heating networks at the plants level. The costs to construct district heating energy centres are highly uncertain according to individual district heating projects. It is common that energy centres generate both heat and power, and previous European studies revealed that the costs of energy centres could differ dramatically depending on the heat-generating technologies and local conditions. This study did not assess specific district heating networks and did not include the costs to construct energy centres from the levelised cost of heat model. Having access to existing district heating networks' cost and operating data could present considerable advantages to evaluate district heating technologies. Subject to data accessibility and resources, further research could gather evidence from existing district heating networks and conduct case studies to further explore the costs to construct and operate energy centres with heat pumps used as primary heat generators.

Through the application of heat pumps and district heating networks, local low temperature waste heat, such as heat from a sewage, could be recycled, upgraded, and delivered to dwellings for heating purposes. This may reduce generation costs and improve the overall competitiveness of district heating networks. This study suggests that utilising free heat sources by low temperature networks and booster heat pumps could significantly reduce the overall cost of heat and capital costs, comparing to situations that large heat pumps are used to generate heat centrally. However, due to limited commercialised examples, the costs of waste heat could be highly uncertain. Further research could explore the utilisation of different types of waste heat in district heating networks and quantify their economic advantages.

Compared to electricity, heat can be stored at a much lower cost. District heating integrated with thermal storage systems could decouple demand and supply and offer operational flexibilities to improve the economy of the system and prepare for peak demand. With the integration of thermal storage technologies and with its additional flexibility and economic advantages, it may make district heating more desirable. Short-term and seasonal thermal storage systems could play an incredibly valuable role with intermittent and seasonal renewable generation. Storage systems may enable district heating operators to reduce their exposures to energy price peaks and ensure supply security. This is an important feature to design operating strategies of combined heat and power systems. This study only considers heat-only generations, further studies could investigate the role of thermal storages in heat pumps and district heating networks, and explore the technical trade-offs and economy of topological configurations to utilise heat pumps, district heating networks, and different types and scales of thermal storages on different temporal resolutions.

Additionally, this study modelled hypothetical district heating networks and potential topological configurations to integrate heat pumps and district heating networks based on how dwellings, heat pumps, and district heating networks are connected. The actual layouts of dwellings, heat pumps, and components of district heating networks are abstracted. As discussed in uncertainty analysis, the design of district heating schemes could determine the network layouts, types and sizes of transport pipes, and the network lengths. Changes in these features could significantly affect the overall heat loss, technical performance, and costs of district heating networks. This study applied a set of assumptions to evaluate hypothetical district heating networks, further research could conduct case studies and apply heat map analysis or GIS drawing for a city or town, to evaluate detailed district heating transport pipes. Moreover, further study could investigate topological configurations with different layout systems of heat pumps and district heating networks, such as star or ring systems, and their integration of various district heating components to assess the technical and economic trade-offs among different designs.

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Appendices

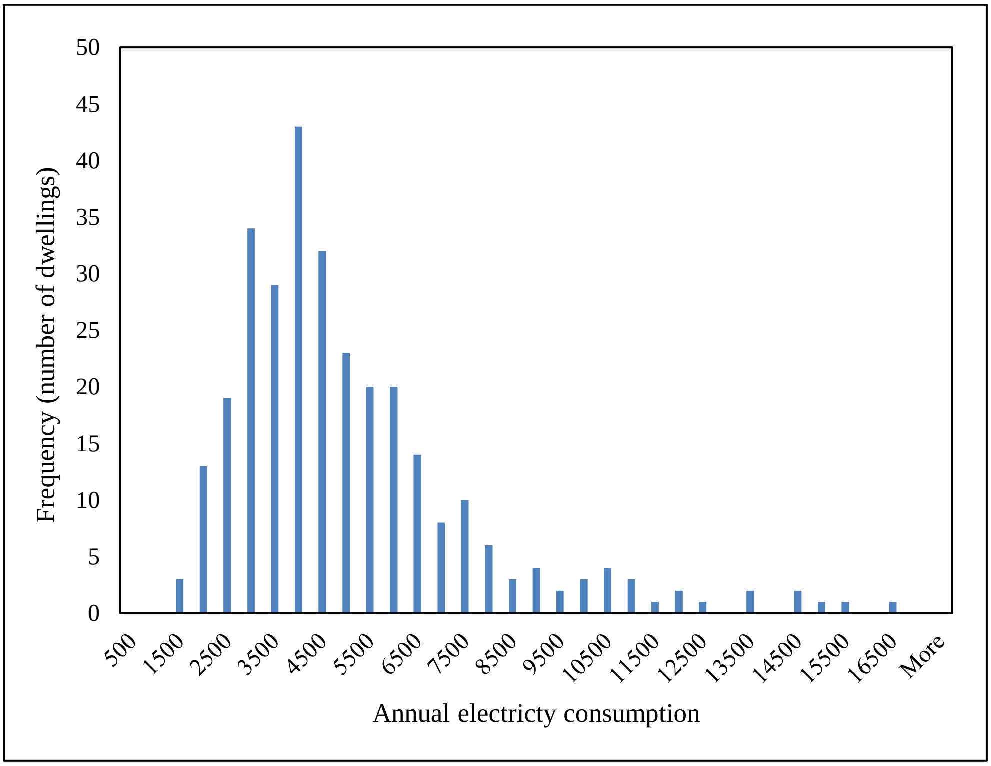
Appendix A.1: A comparison between different versions of the EDRP datasets and their metadata

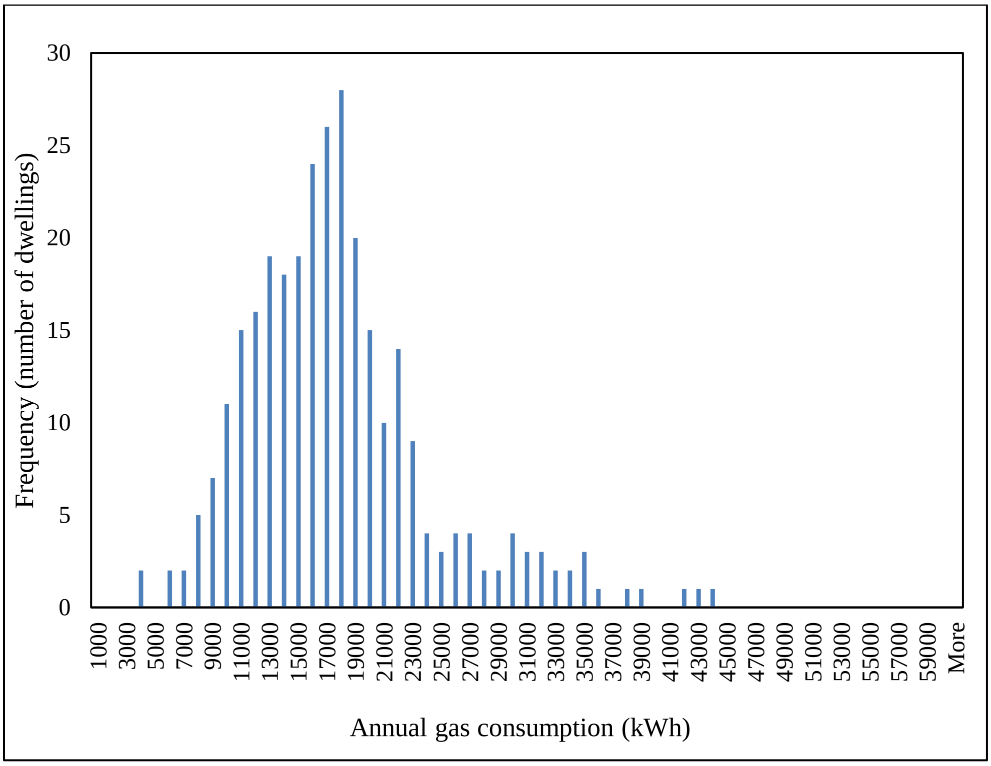
	EDRP on UK data service	**EDRP EDF subset**	**Geospatial and weather data (Chambers, 2017)**	**This study**
Format	CSV	AWS S3 bucket	PostgreSQL, PostGIS, netCDF	PostgreSQL, CSV
Sample size	61,344 (18,370 with smart meters, 8466 dual fuel)	1,979 (1,879 with smart meters, 1048 dual fuel)	1872 plus 77 from SWI and 76 from Pennyland	All EDRP and EDF's subset
Coverage	Great Britain	In London and the southeast of England	In London and the southeast of England	Great Britain
Monitoring period	June 2007 to October 2010	December 2007 to September 2010	January 2008 to October 2010	January 2009 to June 2010
Temporal resolution	30 mins	30 mins	Hourly	30 mins
Metadata	Acorn categories	Postcodes	EDF subset	EDF subset plus external temperature from Chambers (2017)
		Dwelling types and ages	Humidity	
	NUTS-IV Areas	Dwelling ownership	Solar irradiance	
		Number of floors and (bed)rooms	Precipitation	
		Number of male/female occupants	External temperature	
		Occupants age groups	Wind speed	
		Occupants education	Latitude and longitude	
		Occupants language		
		Household segment descriptor		

Appendix A.2: Energy consumption data and statistics of dwellings selected from the EDF subset of the EDRP datasets

Dwelling type and age	Median annual electricity consumption (kWh/year)	Median annual gas consumption (kWh/year)	Sample size
Bungalow & 1919-1944	4296	18843	6
Bungalow & 1945-1964	3790	15859	9
Bungalow & 1965-1980	4956	18048	5
Bungalow & After1980	3691	16175	2
Bungalow & Before1919	0	0	0
Detached & 1919-1944	4647	19113	17
Detached & 1945-1964	4524	22067	15
Detached & 1965-1980	4521	17571	9
Detached & After1980	4485	17000	19
Detached & Before1919	5295	24679	5
Flat/maisonette & 1919-1944	3004	15720	4
Flat/maisonette & 1945-1964	3303	12956	5
Flat/maisonette & 1965-1980	2367	11946	12
Flat/maisonette & After1980	3362	13603	19
Flat/maisonette & Before1919	5213	18263	7
Semi-detached & 1919-1944	5519	17190	32
Semi-detached & 1945-1964	4658	15231	27
Semi-detached & 1965-1980	5556	16984	14
Semi-detached & After1980	4115	15516	17
Semi-detached & Before1919	6386	25846	9
Terraced & 1919-1944	4847	15612	15
Terraced & 1945-1964	4090	14474	12
Terraced & 1965-1980	3571	11394	11
Terraced & After1980	3516	11607	7
Terraced & Before1919	3706	17702	26

Appendix A.3: Annual energy consumption frequencies from the studied 304 dwellings of the EDF subset of the EDRP datasets





Appendix B: The projected future gas and electricity costs, carbon prices, and future carbon intensity of the electricity grid and natural gas

	Electricity	**Electricity**	**Natural gas**	**Carbon price**
Sector	Retail	Wholesale	Retail	
Unit	p/kWh	p/kWh	p/kWh	(£/tCO2e)
2018	17.89	4.51	4.36	4.19
2019	18.33	4.49	4.31	4.37
2020	18.69	4.57	4.31	4.56
2021	18.96	4.64	4.28	4.76
2022	18.54	4.71	4.30	4.94
2023	18.52	4.83	4.35	6.44
2024	18.53	4.99	4.42	10.18
2025	19.58	5.09	4.54	13.21
2026	19.68	4.98	4.61	17.83
2027	18.82	5.37	4.73	24.20
2028	19.44	5.43	4.79	28.82
2029	19.56	5.39	4.86	32.98
2030	19.08	5.88	4.98	39.41
2031	19.95	5.94	5.06	39.41
2032	19.89	5.44	5.06	39.41
2033	19.42	5.42	5.06	39.41
2034	19.35	5.45	5.06	39.41
2035	19.11	4.36	5.06	39.41

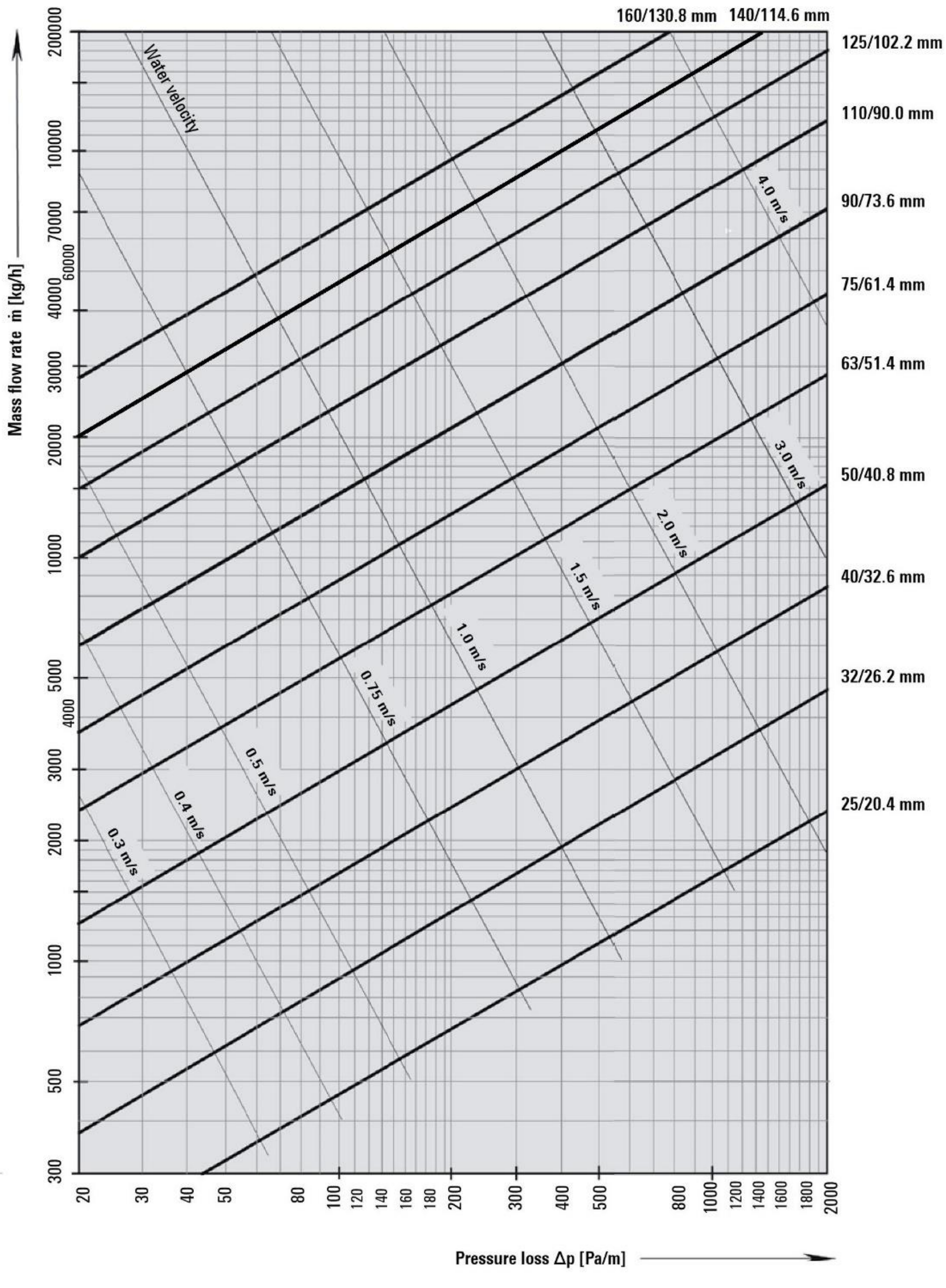
Data from BEIS (2019d).

The projected emission intensity of the electricity grid and gas

Year	Projected emission intensity of the electricity grid	Projected emission intensity of gas	Year	Projected emission intensity of the electricity grid	Projected emission intensity of gas
2018	290.3	184.0	2035	64.6	184.0
2019	272.8	184.0	2036	61.4	184.0
2020	243.0	184.0	2037	58.3	184.0
2021	214.0	184.0	2038	55.4	184.0
2022	197.1	184.0	2039	52.6	184.0
2023	167.8	184.0	2040	50.0	184.0
2024	176.3	184.0	2041	47.0	184.0
2025	165.2	184.0	2042	44.2	184.0
2026	146.8	184.0	2043	41.5	184.0
2027	145.2	184.0	2044	39.0	184.0
2028	121.8	184.0	2045	36.7	184.0
2029	106.5	184.0	2046	34.5	184.0
2030	102.7	184.0	2047	32.1	184.0
2031	96.9	184.0	2048	29.8	184.0
2032	91.5	184.0	2049	27.7	184.0
2033	78.7	184.0	2050	25.8	184.0
2034	77.7	184.0			

Data from CCC (2019).

Appendix C: District heating pipes' pressure loss and mass flow rate chart used to model pumping energy



Source: Brugg (2013), operating with water temperature 80 °C, 6 bar.

District heating pipes' pressure loss and mass flow rate used to model pumping energy, data from Brugg (2013).

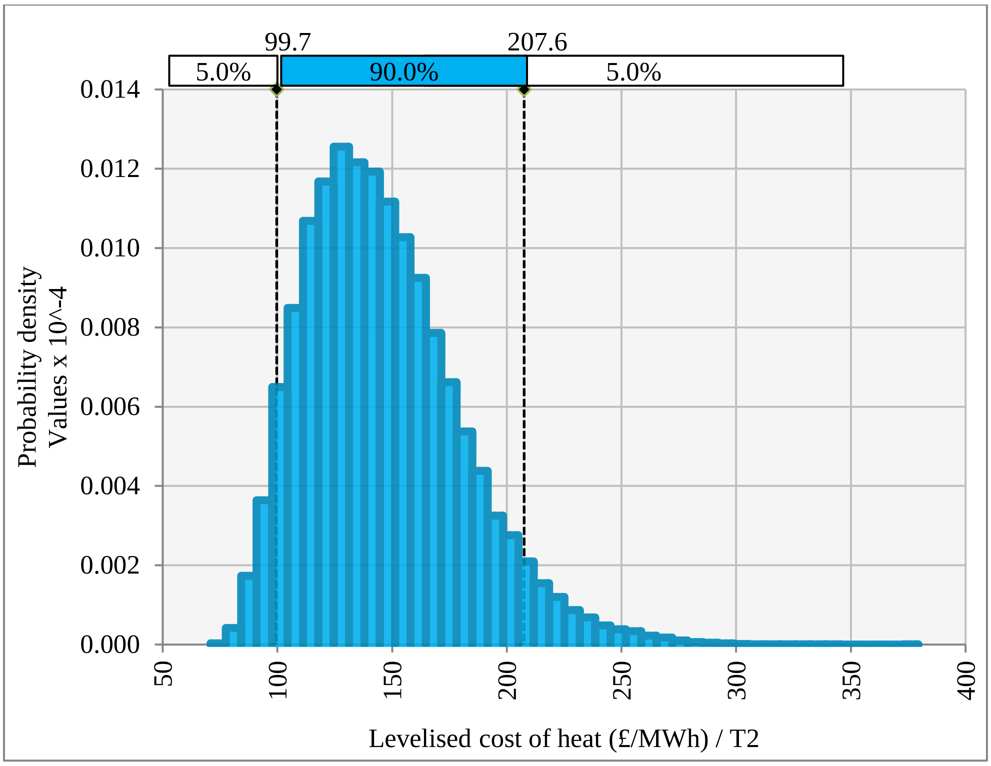
Pipe size											
25/20.4 mm		32/26.2 mm		40/32.6 mm		50/40.8 mm		63/51.4 mm		75/61.4 mm	
Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)
45	300	20	370	22	700	22	1300	20	2500	25	4000
75	400	35	500	28	800	25	1400	30	3000	36	5000
125	500	47	600	32	900	28	1500	55	4000	50	6000
170	600	70	700	40	1000	32	1600	80	5000	65	7000
230	700	80	800	49	1100	36	1700	120	6000	82	8000
290	800	100	900	55	1200	40	1800	160	7000	110	9000
360	900	130	1000	60	1300	42	1900	200	8000	130	10000
420	1000	150	1100	70	1400	50	2000	250	9000	160	11000
500	1100	170	1200	85	1500	100	3000	300	10000	180	12000
600	1200	200	1300	90	1600	180	4000	360	11000	200	13000
700	1300	230	1400	100	1700	270	5000	420	12000	250	14000
800	1400	260	1500	110	1800	400	6000	480	13000	280	15000
900	1500	280	1600	140	1900	500	7000	550	14000	300	16000
1000	1600	310	1700	150	2000	600	8000	600	15000	350	17000
1100	1700	350	1800	300	3000	800	9000	700	16000	400	18000
1200	1800	400	1900	500	4000	900	10000	800	17000	420	19000
1300	1900	430	2000	800	5000	1100	11000	850	18000	450	20000
1400	2000	900	3000	1100	6000	1400	12000	950	19000	600	25000

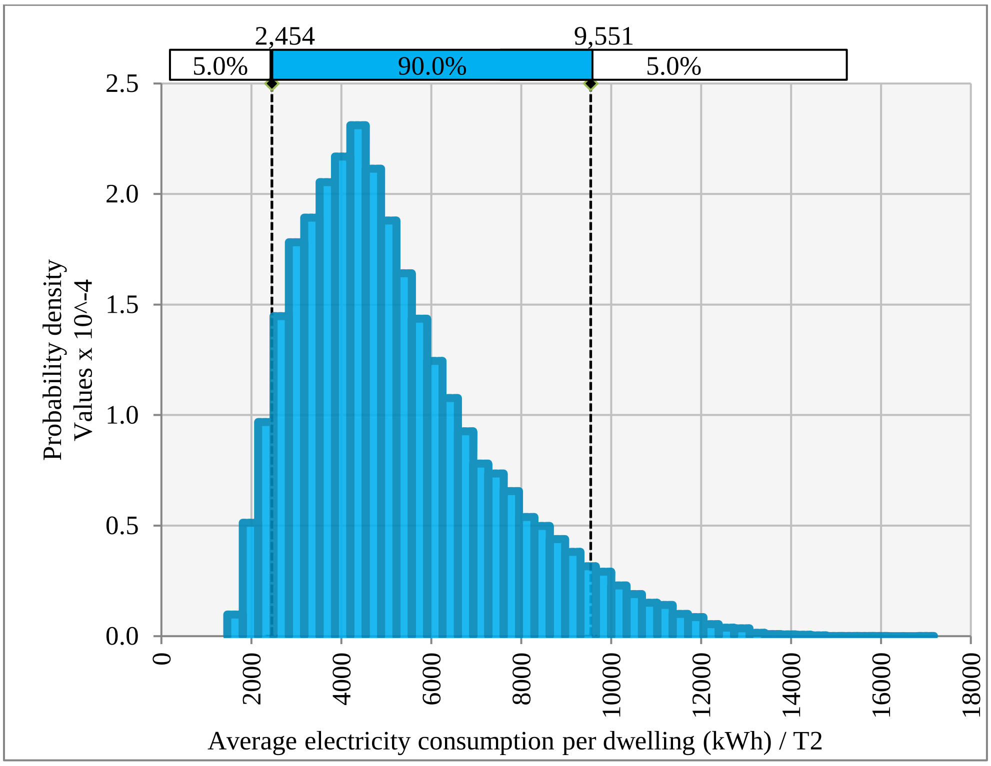
Pipe size									
90/73.6 mm		110/90.0 mm		125/102.2 mm		140/114.6 mm		160/130.8 mm	
Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)	Pressure loss (ΔP Pa/m)	Mass flow (kg/h)
20	6000	20	10000	20	15000	20	20000	23	30000
28	7000	25	11000	24	16000	26	25000	30	35000
35	8000	29	12000	26	17000	42	30000	40	40000
42	9000	32	13000	28	18000	55	35000	60	50000
50	10000	38	14000	19	19000	75	40000	90	60000
60	11000	42	15000	36	20000	110	50000	130	70000
70	12000	48	16000	45	25000	170	60000	150	80000
95	13000	52	17000	72	30000	210	70000	190	90000
100	14000	58	18000	100	35000	270	80000	220	100000
120	15000	65	19000	140	40000	320	90000	270	110000
130	16000	70	20000	200	50000	400	100000	300	120000
150	17000	100	25000	290	60000	480	110000	350	130000
160	18000	160	30000	390	70000	550	120000	400	140000
170	19000	200	35000	500	80000	650	130000	450	150000
180	20000	280	40000	590	90000	700	140000	500	160000
250	25000	410	50000	700	100000	800	150000	580	170000
400	30000	580	60000	800	110000	900	160000	600	180000
550	35000	800	70000	1000	120000	1000	170000	700	190000

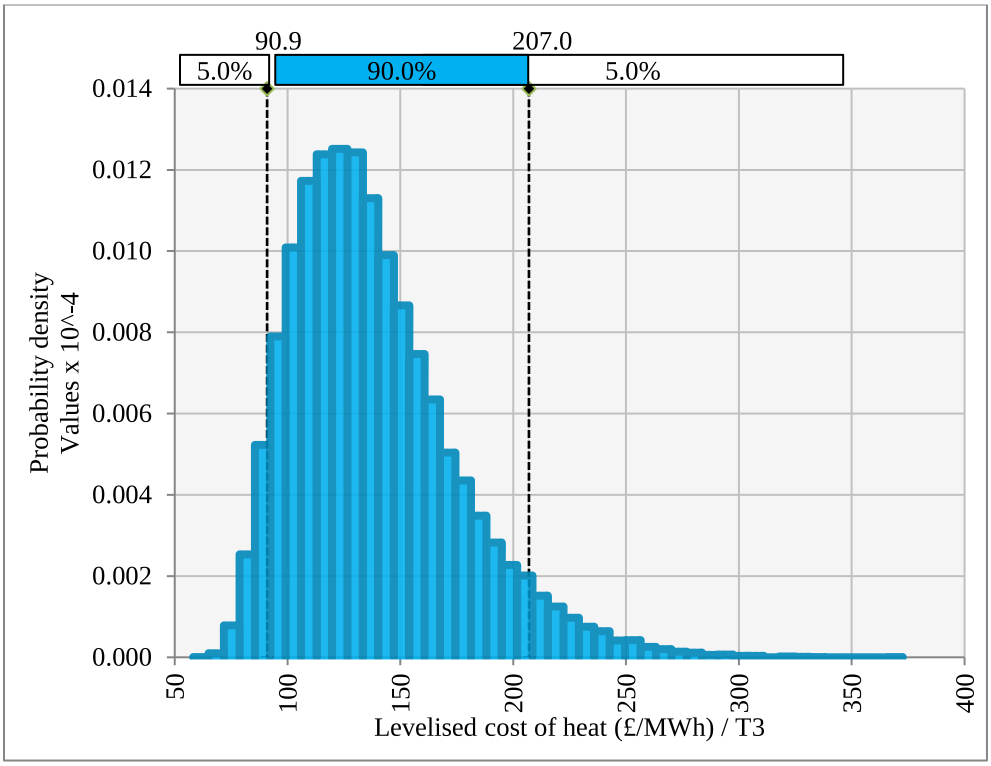
Appendix D: Heat pumps and district heating model inputs and their variations for sensitivity analysis

Model input	Baseline	Lower bound	Upper bound
Ambient temperature (℃)	10	5	15
Annual heat demand per dwelling (kWh)	14303	7151.5	21454.5
Booster HP capital cost (£)	4000	2000	6000
Booster HP efficiency factor (η)	0.5	0.25	0.75
Booster HP O&M cost (£/year)	90	45	135
Capital cost for replacement (%) / 25 years	50	25	75
Discount rate (%)	3.5	1	10
Domestic HIUs per dwelling (£)	1075	537.5	1612.5
Heat meter cost per dwelling (£)	579	289.5	868.5
Heat meter maintenance (£/MWh)	3.4	1.7	5.1
Heat network maintenance (£/MWh)	0.6	0.3	0.9
Heat source temperature (℃)	10	5	15
HIUs maintenance cost (£/MWh)	9	4.5	13.5
Labour for metering, billing and revenue (£/MWh)	16.9	8.45	25.35
Large HP capital cost (£/kW)	600	300	900
Large HP efficiency factor (η)	0.7	0.35	1
Large HP O&M cost (£/kW)	1	0.5	1.5
Length of service pipework per dwelling (m)	13.3	6.65	19.95
Main network (buried pipes) cost (£/m)	1600	800	2400
Network (internal pipes) unit cost (£/m)	415	207.5	622.5
Peak hourly demand (kW, large network)	11040	5520	16560
Pipe insulation thickness (mm)	50	25	75
Substation cost per kW capacity (£/kW)	35	17.5	52.5
Substation maintenance (£/MWh)	0.5	0.25	0.75
T2 operating temperature flow (℃)	80	40	120
T2 operating temperature return (℃)	60	30	90
T3 and T4 operating temperature flow (℃)	30	15	45
Thermal conductivity of pipes (W/mK, max 6 Bar)	0.03	0.015	0.045
Total length of transport pipes (m, large scale network)	3180	1590	4770

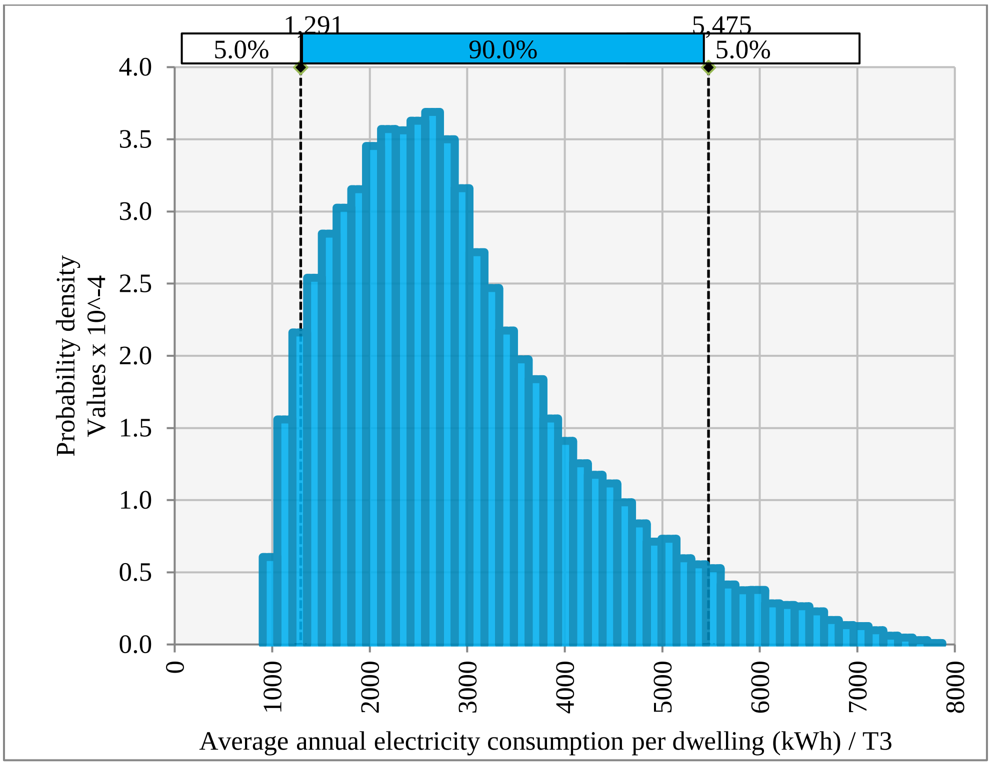
Monte Carlo simulation: Probability density and LCOH for heat pumps and district heating topological configurations.



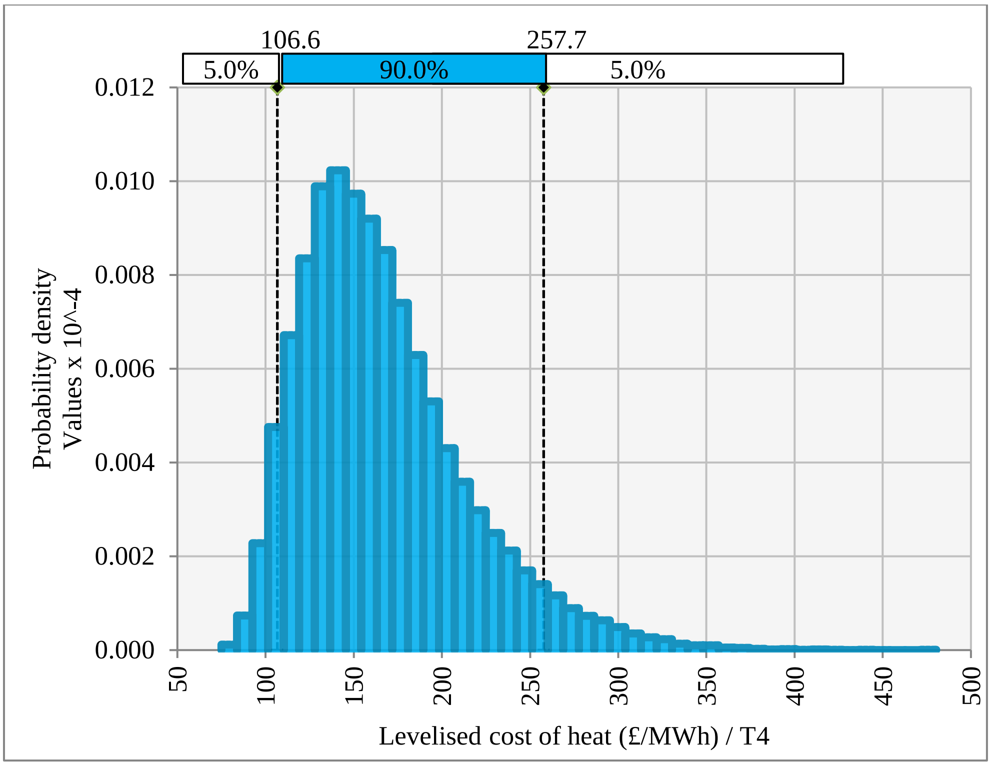




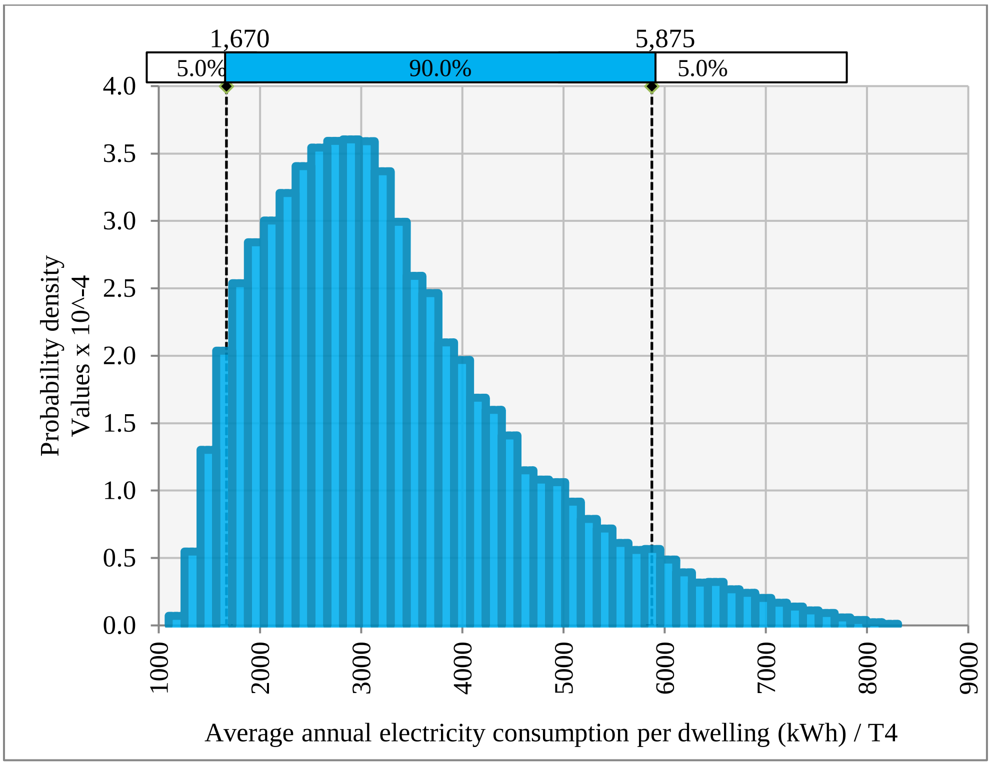
90.9
207.0
5.0%
90.0%
5.0%
Probability density
Values x 10^-4
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
50
100
150
200
250
300
350
400
Levelised cost of heat (£/MWh) / T3



1,291
5,475
5.0%
90.0%
5.0%
Probability density
Values x 10^-4
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0
1000
2000
3000
4000
5000
6000
7000
8000
Average annual electricity consumption per dwelling (kWh) / T3



106.6
257.7
5.0%
90.0%
5.0%
Probability density
Values x 10^-4
0.012
0.010
0.008
0.006
0.004
0.002
0.000
50
100
150
200
250
300
350
400
450
500
Levelised cost of heat (£/MWh) / T4



1,670
5,875
5.0%
90.0%
5.0%
Probability density
Values x 10^-4
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Average annual electricity consumption per dwelling (kWh) / T4

Appendix E: Acronyms

4GDH	Fourth Generation District Heating
ADE	Association for Decentralised Energy
ADMD	After Diversity Maximum Demand
ASHP	Air source heat pump
AWS	Amazon Web Services
BEIS	Department for Business, Energy and Industrial Strategy
BI	Business intelligence
BRE	Building Research Establishment
CCC	Committee on Climate Change
CEDA	Centre for Environmental Data Analysis
CFSR	Climate Forecast System Reanalysis
CHP	Combined Heat and Power
CIBSE	Chartered Institution of Building Services Engineers
COP	Coefficient of Performance
CSE	Centre for Sustainable Energy
DEA	Danish Energy Agency
DECC	Department of Energy and Climate Change
DEN	District Energy Network
DH	District Heating
DS	Dansk Standard
ECUK	Energy consumption in the UK

EDRP	Energy Demand Research Project
EHPA	European Heat Pump Association
EST	Energy Saving Trust
ETI	Energy Technologies Institute
GDPR	General Data Protection Regulation
GIS	Geographic Information System
GLA	Greater London Authority
GSHP	Ground source heat pump
HNDU	Heat Networks Delivery Unit
HNIP	Heat Networks Investment Project
HP	Heat Pump
HRE	Heat Roadmap Europe
HSE	Health and Safety Executive
IEA	International Energy Agency
LAUs	Local Administrative Units
LCICG	Low Carbon Innovation Co-ordination Group
LCOE	Levelised cost of energy
LCOH	Levelised cost of heat
NEA	Nuclear Energy Agency
NUTS	Nomenclature of Units for Territorial Statistics
NWP	Numerical Weather Prediction
O&M	Operations and Maintenance

OECD	Organisation for Economic Co-operation and Development
Ofgem	Office of Gas and Electricity Markets
PETA	Pan-European Thermal Atlas
PTG	Power Temperature Gradient
RHI	Renewable Heat Incentive
RHPP	Renewable Heat Premium Payment
RHPP	Renewable Heat Premium Payment
SDHA	Swedish District Heating Association
SMETS	Smart Metering Equipment Technical Specifications
SPF	Seasonal Performance Factor

[End]