element**energy**

London's Climate Action Plan:

WP3 Zero Carbon Energy Systems

Report for

Greater London Authority
& C40 Cities

September 2018

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Contents

Acknowledgements

We would like to thank the stakeholders who provided key input to this project.

Organisation	Topic
National Grid	Gas network scenarios
	Isle of Grain
Transport for London	Transport scenarios
Cadent	Gas network scenarios
UK Power Networks	Electricity distribution infrastructure impacts and planning
SGN	Gas network scenarios
Orange Gas	Transport scenarios
Certas	Transport scenarios
Vattenfall	District heating scenarios & Amsterdam case study
Cities	Manchester case study
	Bristol case study
	Toronto case study
	Gothenburg case study
	Seoul case study
UCL	Energy system scenarios

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1 Executive Summary

1.1 Project Introduction

Element Energy was commissioned by C40 Cities Climate Leadership Group and the Greater London Authority (GLA) to undertake an analysis of decarbonisation pathways to inform London's strategy on energy and climate. The study investigates several scenarios in which various technology options are deployed to decarbonise heating and transport, and examines the implications for infrastructure and the wider energy system. The results of the analysis have informed London's carbon budgets and will support energy policy decisions on low regrets actions in the short term. The findings will also inform the key decision points where the potential pathways to deep decarbonisation diverge more clearly in the medium term.

This study aims to provide a clear and transparent assessment of the likely costs of decarbonising London's energy system. It also highlights the impact of uncertainties over the viability of implementing the different pathways and the practical barriers to achieving the required deployment of low carbon technologies. The work includes an analysis of the impact of each scenario on London's electricity grid, and the potential benefits of various types of energy storage and DSR for London's energy system.

Each of the scenarios represents a different pathway to meeting London's decarbonisation goals. The scenarios rely on various technologies and require different supporting policy, but are intended to represent a similar overall level of policy ambition:

- **Baseline (with high energy efficiency uptake) scenario** represents the likely outcome with minimal change to current policies on low-carbon technologies, with the exception of energy efficiency, for which the same high level of uptake is applied as for all scenarios. There will be a relatively low uptake of most low carbon technologies beyond 2025.
- **Decentralised scenario** promotes decentralised energy production and distribution. This results in high uptake of heat networks and solar PV, as well as some additional decarbonisation through blending of biomethane and bio-synthetic natural gas into the gas grid.
- **High electrification scenario** promotes electrification of heat and transport using an increasingly decarbonised electricity grid. There will be high uptake of heat pumps and electric vehicles and a requirement for significant application of DSR and energy storage. It is assumed that the gas grid is no longer economically viable in 2050.
- **Decarbonised gas scenario** promotes the conversion of London's gas grid to 100% hydrogen by 2045. Heating remains predominantly gas (hydrogen) boilers, with some heat networks. Transport includes a large share of hydrogen fuel cell electric vehicles.
- **Patchwork scenario** aims to represent a pragmatic, mixed pathway, encompassing aspects of all the above scenarios to meet carbon targets.

1.2 Summary of Key Findings

Low regrets actions for the short and medium term

There are several policy actions that could be taken immediately, either locally or nationally, to support technologies at the minimum levels present in all scenarios and to enable a decision on the preferred scenario in the late 2020s. These low regrets actions entail significant activity from 2020, meaning that decisions by local and national government on the form of the supporting policy need to be made in 2018-19.

- **Energy efficiency bringing 70% of London's buildings to EPC C or above by 2030**

The extensive deployment of building energy efficiency measures, covering heat, lighting and appliances, reduces energy use and the cost of energy to consumers regardless of the scenario ultimately chosen. The resulting decrease in building electricity demand for lighting and appliances also facilitates the uptake of heat pumps and electric vehicles by easing pressures on the electricity network. Rapid uptake of energy efficiency measures is difficult to achieve due to their high initial capital cost, in-home disruption, long payback times, and the frequent misalignment of incentives between landlords and tenants. This effort is therefore likely to involve fiscal incentives, local government-initiated programmes to support some market sectors, and the introduction of minimum energy standards for all buildings.

- **Rollout of heat networks to an additional 70,000 homes by 2025**

All scenarios considered in this report include at least 100,000 homes connected to district heating by 2025, an increase of 70,000 over current levels[1]. These heat networks should be deployed in the most cost-effective locations and make use of London's valuable waste heat. High capital cost and project complexity are the main barriers to heat network deployment; reaching the level of uptake proposed here will require the mechanisms for successful consumer engagement, stakeholder collaboration, and scheme financing to be developed. The experience gained from early deployment of heat networks will provide information on the cost and viability of deployment at scale and will thereby help to inform the decision on London's preferred long-term decarbonisation pathway. Financial and logistical support, supply side training, and regulation ensuring fair outcomes for consumers are likely to be needed to realise this level of heat network deployment. Consideration should also be given to heat zoning for networks in new build areas, where consumers are obligated to connect where practicable, or excluded from other technology subsidies.

- **Deployment of heat pumps in more than 300,000 buildings by 2025**

A step-change in the level of heat pump uptake between now and 2025 is required in three of the four decarbonisation scenarios studied. These scenarios include at least 300,000 heat pumps deployed by 2025, compared with the very low levels of current deployment. 250,000 of these heat pumps are likely to be in new buildings while 50,000 will be deployed in existing buildings. Heat pump uptake is primarily limited by the somewhat higher capital costs compared to other heating systems, relatively under-developed supply chain and lack of consumer familiarity. More widespread deployment of heat pumps in the 2020s will enable early assessment of consumer acceptance, the required level of financial support, and the effectiveness of supporting policy. The level of cost reduction achieved through supply chain improvements and manufacturing economies of scale will also affect London's preferred path. Heat pump deployment could be targeted initially towards new buildings, where no additional building renovation is required, and in off-gas buildings where fewer low carbon options are available and heat pumps will have the highest impact in carbon reduction terms. However, some substantial deployment of heat pumps in existing on-gas dwellings will also be important to understand the consumer attitude towards the technology in that segment, in order to assess the viability of the highest heat pump deployment pathways. Deployment of heat pumps in new buildings can be driven by building regulations. A step-change in the level of deployment of heat pumps in existing buildings is likely to require a reformulation of the Renewable Heat Incentive (RHI) (or another fiscal incentive scheme) to provide a more attractive offer to consumers, information campaigns to increase awareness of the technology, and installer training.

- **New-build regulations mandating high efficiency and low carbon heating**

The London Plan mandates high energy efficiency and carbon standards for new buildings. These measures are needed to avoid locking in higher than necessary energy demand and fossil-based heating for a generation of new buildings. Misalignment of incentives between developers and future residents, and a lack of consumer familiarity with low carbon systems, present obstacles to the construction of high efficiency buildings. New buildings are a key early market for both heat pumps and heat networks, and achieving the low regrets levels of deployment of these technologies described above will require most new buildings to be served using one of these technologies from 2020 onwards. The Mayor's zero carbon standard (currently applicable to major domestic developments) already encourages the uptake of building-level heat pumps and district heating, and should continue to be monitored and strengthened.

- **Coordination of EV charging infrastructure deployment**

Plug-in hybrid and battery electric vehicles make up around 10% of passenger vehicles in all scenarios by 2025, and will rely on a London-wide network of home, workplace, public, and rapid charge points. In areas without

[1] District heating is an efficient way of providing low carbon heat in high density areas. Its potential benefits to London are recognised in the London Environment Strategy, which specifies a target of 15% decentralised energy by 2030.

off-street parking, significant on-street charging infrastructure is required to avoid limiting the uptake of electric vehicles. Several deployment schemes are already under way, and continued coordination and logistical and financial support for the rollout of these charge points will facilitate the uptake of low emissions vehicles, especially in areas of London with limited off-street parking. Coordination efforts should ensure that public charge points (whether installed by private companies or the individual boroughs) are compatible with the widest possible range of vehicles and that impacts on the electricity grid can be managed.

Key decision points

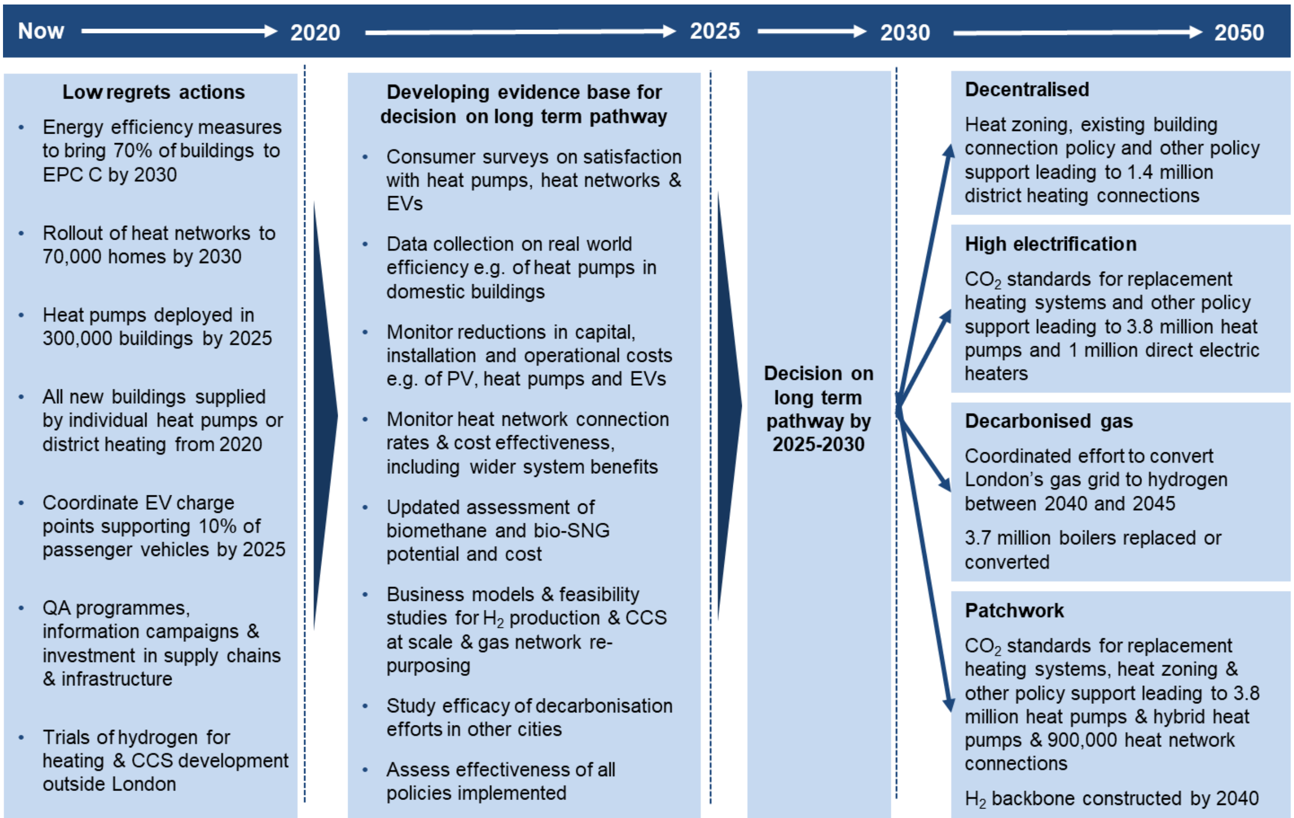
Beyond the low regrets actions, planning needs to start now in order to ensure that decisions on the longer term decarbonisation pathway can be made by the mid-2020s, when the various scenarios described below diverge more clearly. Each scenario focuses the greatest policy effort in a single area (district heating, heat pumps, or full hydrogen grid conversion) to reflect approximately equivalent levels of policy ambition. Figure 1-1 presents a timeline of the actions and decisions discussed.

In the Decentralised scenario, a heat zoning policy to drive high levels of connection to existing domestic buildings is implemented around 2025. This is a challenging policy to enact given that it is likely to impact on consumer choice, and there will be a need to ensure fairness and value for money. This scenario will also require the delivery of a large volume of associated infrastructure, which represents another key challenge.

The High electrification and Patchwork scenarios entail a similar decision in the 2020s, in this case to limit (likely through regulation) the carbon intensity of replacement heating systems in existing buildings in addition to the further strengthening of new build regulation. This, too, is an ambitious policy decision that addresses the most challenging segment – existing domestic buildings – but is required to achieve the levels of heat pump uptake needed to decarbonise the heating sector in these scenarios.

In the Decarbonised gas scenario, a national decision on the future of the gas network, and the option of large-scale use of hydrogen, is required around 2025. This will allow time for the development of hydrogen production and delivery technologies, carbon capture and storage (CCS) and hydrogen-using appliances; for national and local planning for the extensive infrastructure deployment entailed; and for the safeguarding of strategic sites and assets as required. To enable this decision to be taken by around 2025, the necessary research and trial programmes to demonstrate feasibility should be completed in advance of this date, as there is still a large uncertainty and significant risk around this scenario.

Figure 1-1 Low regrets actions and key decision points to decarbonise London's energy system



Scenario Description

Table 1-1 presents an overview of the technology uptake levels included in each of the five scenarios, which have been defined assuming a similar level of policy ambition in each. All scenarios include the same high level of energy efficiency uptake[2] to isolate the climate, infrastructure, and cost impacts of each.

[2] The work around energy efficiency measures and solar thermal deployment was completed as part of Work Package 2 of London's Climate Action Plan, led by Arup for the GLA.

Table 1-1 Scenario definition in terms of deployment of technologies in London by 2050

	Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Electricity Grid	Low	High			
	155 gCO_2/kWh by 2050	Falls to 28 gCO_2/kWh by 2050			
Energy Efficiency	High energy efficiency retrofit standards				
	81% of buildings EPC C or better, 50% appliance energy reduction, 80% lighting energy reduction by 2050				
Solar thermal	Arup central scenario				
	4% buildings, 0.26 TWh/year				
Heat Pumps	Low	Medium	High	Low	High
	<5% buildings	32% buildings	75% buildings	<5% buildings	75% buildings
Heat networks	Low	High	Low	Medium	Medium
	6% buildings	27% buildings	6% buildings	18% buildings	18% buildings
Green gas & Hydrogen	Low	Medium	Low	High	Medium
	1.3 TWh green gas	7 TWh green gas	1.3 TWh green gas, then gas grid decommissioned	100% H_2 gas grid conversion	7 TWh green gas + 7% H_2 blending + H_2 backbone
Solar PV	Low	High	High	Medium	Medium
	2% buildings	10% buildings	10% buildings	4% buildings	4% buildings
Transport	Low	High - 100% ZEV's by 2050			
	Tfl Baseline scenario	Tfl MTS Scenario with high BEVs	Tfl MTS Scenario with high BEVs	Tfl MTS Scenario with high H_2 FCEVs	Tfl MTS Scenario with selective H_2 FCEVs

Emissions and energy results

All scenarios considered achieve significant decarbonisation beyond the Baseline scenario. Three of the scenarios considered reach an emissions level below 5 $MtCO_2$ per year in 2050, a reduction of at least 90% over London's 1990 carbon emissions. The London Environment Strategy[3] recognises that residual emissions, for example in aviation, industry and existing building stock, will need to be addressed through emissions offsetting or negative emissions technologies.

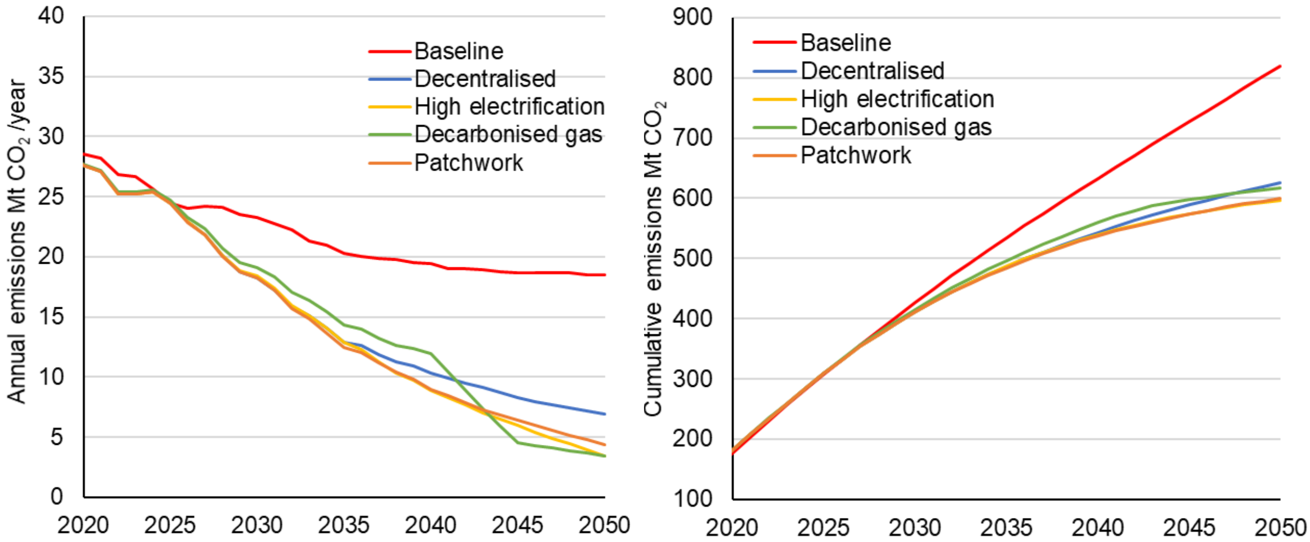
The annual emissions trajectories of the scenarios are shown in Figure 1-2 and the carbon reduction achieved by 2050 is presented in Table 1-2. Under the Baseline scenario decarbonisation is slow and stagnates after 2035-2040 at around 19 $MtCO_2$ per year. The other scenarios achieve faster decarbonisation and continue to cut CO_2 emissions to 2050. In the Decentralised scenario emissions fall to below 7 $MtCO_2$ per year by 2050, while in the High electrification, Decarbonised gas and Patchwork scenarios emissions are reduced further to below 5 $MtCO_2$ per year. The Decarbonised gas scenario would be likely to result in the highest local NO_x emissions from the heating sector; the other decarbonisation scenarios contain a higher proportion of electric forms of heating, which have the lowest impact on air quality locally. The most efficient use of fuels occurs in the Patchwork scenario, due to extensive use of environmental and waste heat sources through heat pumps and heat networks.

However, while those scenarios achieve comparable levels of emissions reduction by 2050, the cumulative emissions to 2050 vary due to the different decarbonisation trajectories. The Decarbonised gas scenario leads to higher cumulative emissions than the High electrification and Patchwork scenarios due to the delay in decarbonisation of heat through hydrogen conversion, which cannot be implemented as early as the electric heating options due to lower technology readiness. The High electrification and Patchwork scenarios follow similar trajectories and achieve cumulative emissions to 2050 below 600 $MtCO_2$. Cumulative emissions in the Decarbonised gas scenario are around 3% higher at 617 $MtCO_2$. Apart from the Baseline, the highest cumulative

[3] *London Environment Strategy*, Greater London Authority, May 2018

emissions occur under the Decentralised scenario where large numbers of gas boilers remain in areas where heat networks are not cost effective.

Figure 1-2 Emissions results for the five scenarios, annual (left) and cumulative to 2050 (right)



Investment results

The results of the investment analysis for each scenario are summarised, alongside the emissions results, in Table 1-2. The costs presented are discounted cumulative scenario costs to 2050 which are then divided into building-level costs, infrastructure costs, and fuel costs. The relative cost difference between the scenarios, whilst significant in absolute terms, is less than 10% of the cumulative cost to 2050. In all scenarios, the fuel costs are the largest proportion of the total, followed by building-level costs and finally infrastructure costs. Fuel costs are higher in the Baseline scenario than the other four scenarios due to the high cost of petrol and diesel, coupled with the lower efficiency of petrol and diesel vehicles versus battery and fuel cell electric vehicles.

Table 1-2 Summary of scenario emissions and discounted cumulative scenario investment results to 2050

Results summary		**Baseline**	**Decentralised**	**High electrification**	**Decarbonised gas**	**Patchwork**
Annual 2050 emissions $MtCO_2$		18.5	6.9	3.4	3.5	4.4
Cumulative emissions to 2050		820	626	597	617	600
Total cumulative cost £ bn	Low	£256	£257	£270	£252	£265
	Central	**£278**	**£279**	**£292**	**£274**	**£287**
	High	£299	£298	£311	£294	£308
Central cumulative cost £bn	Building level	£39	£49	£57	£42	£56
	Infrastructure	£1.8	£6.5	£4.4	£5.8	£5.1
	Fuel	£238	£224	£231	£227	£226
Cost uncertainty (High - low cost difference)	Building-level	£0.3	£2.1	£4.5	£0.3	£4.4
	Infrastructure	£0.5	£1.3	£1.0	£1.8	£1.3
	Fuel	£42	£38	£35	£40	£38
	Total	£42	£41	£41	£42	£43

The cumulative cost of the Decarbonised gas scenario is lower than that of the Baseline scenario, and the Decentralised scenario cost is almost equal to the Baseline scenario. While the Decentralised scenario does not reach the level of decarbonisation realised in the other scenarios, Decarbonised gas achieves nearly the lowest 2050 annual emissions. These two scenarios entail the highest infrastructure costs (for heat network development and conversion of the gas grid in the scenarios, respectively), and a high level of coordination between multiple public and private infrastructure stakeholders is required in both scenarios. Significant technical uncertainty remains for the Decarbonised gas scenario. As described above this scenario leads to higher cumulative emissions to 2050 than some other scenarios, reflecting delayed action, which increases the risk of falling short of deep decarbonisation by 2050. Nonetheless, the potential for the Decarbonised gas scenario to deliver decarbonisation at lower cost justifies further serious consideration of this option to better understand its cost and viability.

There are necessarily significant uncertainties associated with the cost of each pathway. The largest absolute cost uncertainty is associated with the fuel costs, as they are the largest contribution to the overall cost. The uncertainty around hydrogen retail prices is significantly larger than that around more conventional fuels, so the Decarbonised gas scenario cumulative fuel cost varies more between the low and high cases than the other scenarios, with the exception of the Baseline scenario. High uncertainty in building level costs occurs where building level costs are highest, as in the High electrification and Patchwork scenarios due to high uptake of heat pumps. In the Decarbonised gas scenario, the cost of hydrogen boilers can be estimated with higher confidence, while the cost of producing low carbon hydrogen and repurposing the gas grid is considerably more uncertain. However, there are wider uncertainties around the feasibility of delivering hydrogen safely within the home. Since these uncertainties are difficult to quantify in cost terms, these are considered 'stop-go' uncertainties, where the cost may be prohibitively high[4].

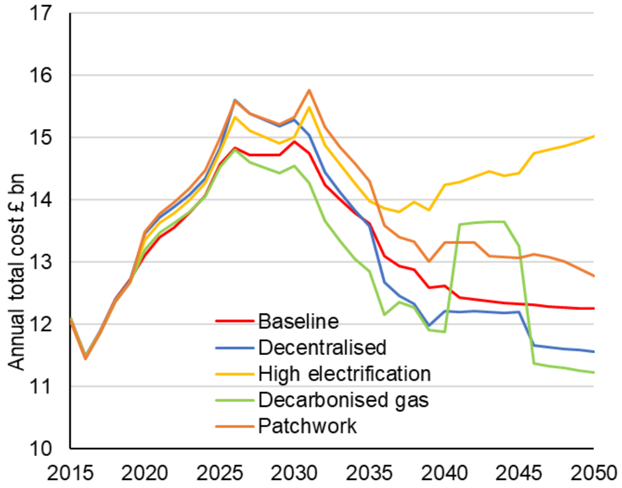
The annual (undiscounted) cost of each scenario is shown in Figure 1-3, which presents total cost (left) and cost per capita (right). The per capita cost is not intended to represent an actual consumer bill and does not consider the likely distribution of costs between consumers of various types (e.g. homeowners and renters), but allows a cost comparison in more familiar units. All investments will ultimately be paid for by consumers (as citizens), although some will be paid for directly when the cost is incurred, and other investments will be made by the public or private sector and socialised or recovered through service charges or taxes.

All scenarios see an increase in annual cost between 2020 to 2035 as infrastructure and building-level systems, including energy efficiency measures, are first deployed at scale. After 2035 the annual costs of the scenarios diverge more significantly as low carbon systems reach higher penetration levels and the differential cost of the fuels used in each scenario becomes more significant. The uptake of battery and fuel cell electric vehicles causes reductions in cost in all scenarios apart from the Baseline due to their increased efficiency over conventional vehicles. Meanwhile heating costs are higher than the Baseline in the other scenarios as the Baseline includes high energy efficiency uptake without changes in heating technology. In the High electrification and Patchwork scenarios, this increase is driven by the the high capital cost of heat pumps. The high fuel cost of direct electric heating further increases the overall cost in the High electrification scenario. The per capita cost follows the same trends, but is reduced in all scenarios relative to 2015 by the forecast increase in London's population.

The scenarios will impact on consumers in ways other than added cost. Both heat pumps and electric vehicles will likely require consumers to modify their usual behaviour, potentially causing inconvenience and perception of reduced quality of service. Disruption within the home when systems are retrofitted in existing buildings and from road works during the development of heat and hydrogen networks will also affect consumers.

[4] *Cost analysis of future heat infrastructure options*, report for National Infrastructure Commission, Element Energy & E4tech, 2018

Figure 1-3 Annual scenarios costs to 2050 overall (left) and per capita (right)



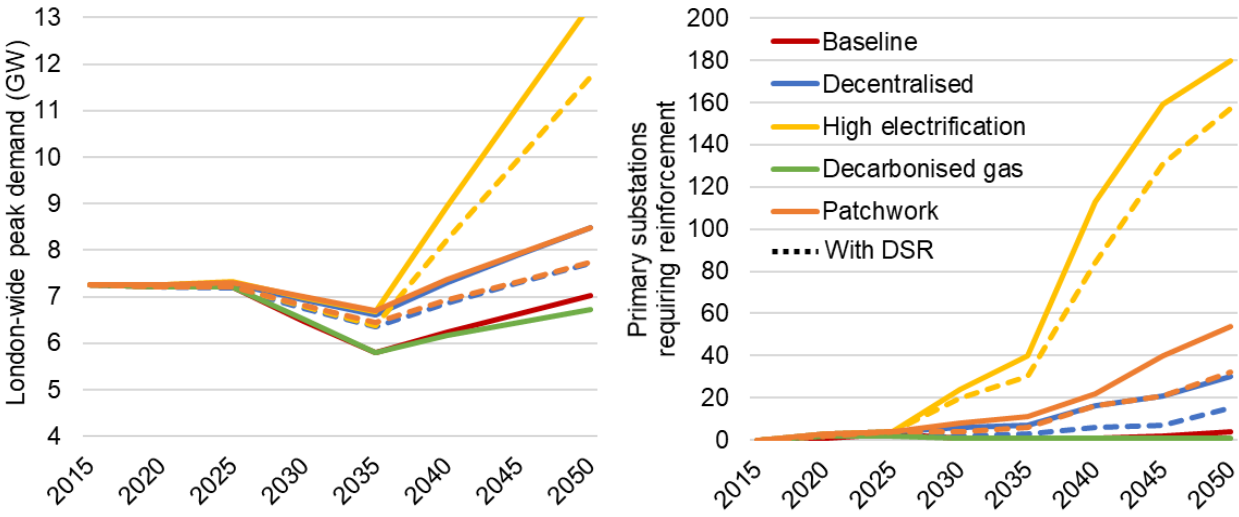
Electricity grid, energy storage and DSR

A spatial analysis of the peak electricity demand in London was undertaken to understand the relative impact on the electricity grid of each scenario and the associated cost. It is found that the ambitious energy efficiency deployment assumed across all scenarios largely offsets the increase in peak electricity demand due to electrification of heat and transport, on a London-wide scale, to 2035. It is important to caveat that if energy efficiency uptake is lower than the levels presented in the scenarios, the impact on the electricity grid would be larger than shown here. Further, while the spatial analysis accounts at a relatively high level for the likely spatial distribution of technologies, variation of technology deployment at a local level could lead to requirements for reinforcement in some locations earlier than presented here. It should be noted that the analysis assumes that peak electricity loads are principally driven by domestic heating and lighting and therefore occur in January. A significant minority of substations, predominately in central London, are dominated instead by commercial buildings whose need for reinforcement is determined by summer air conditioning use.

Beyond 2035, where little further energy efficiency can be applied, the High electrification scenario entails substantial requirements for grid reinforcement, as shown in Figure 1-4. The peak electricity demand is increased from 7.3 GW today to over 13 GW by 2050. Without accompanying measures to incentivise DSR and energy storage, this increase would require additional investment of more than £900 million at distribution and transmission level, with up to £500 million in additional peak generation capacity on the national grid to 2050. Plausible levels of deployment of DSR and additional thermal storage have the potential to reduce the peak demand to 11.5 GW and the required network and generation level investment required to 2050 by around £600 million. Although the cost of this level of thermal storage is estimated to be in the region of £200 million, reducing the net benefit, thermal storage could bring additional benefits not included in the scope of this analysis including other services to the grid and to energy suppliers. Electrical storage can also be used to reduce the need for network reinforcement, but has not been included in the results because it is not currently economic on the basis of deferred grid reinforcement alone, and there are large uncertainties over the long term cost reduction. However, the business case would likely be more attractive when other services provided by electrical storage are considered.

Overall, this analysis suggests that the need to upgrade the electricity grid should not be considered a barrier to decarbonisation as the costs involved, although substantial, are not unmanageable compared with the total business as usual energy system investment required to 2050. It will nonetheless be important that investment in electricity grid upgrades is able to take place in advance of need, in order to ensure the rollout of electric heating and transport technologies can be accommodated without grid upgrade work leading to delays.

Figure 1-4 London-wide peak electricity demand (left) and the number of primary substations requiring reinforcement (right)



Final Remarks

There is sufficient time to plan for the large infrastructure investments required in each scenario, but the following actions are needed with some urgency to continue London’s decarbonisation at the necessary rate and to provide evidence to inform a decision on the long-term decarbonisation pathway by the mid-2020s.

- Implement enhanced energy efficiency retrofit scheme for existing buildings[5] to bring 70% of buildings to rating EPC C or above by 2030
- Continue to support boroughs in enforcing planning policy to maximise energy efficiency, deployment of heat pumps and heat network connections in new buildings where appropriate
- Develop a pilot programme for heat pump deployment in both off-gas and on-gas properties, including information campaigns, real-world data collection, and installer quality assurance, and undertake associated research on consumer satisfaction and local area grid impacts
- Maintain a list of priority areas for heat network development, which should include areas being newly or re-developed as well as those near to waste heat resources
- Continue to review and strengthen planning requirements and provide support to boroughs to ensure that heat networks developed comply with guidance from the Heat Trust and the Heat Networks Code of Practice[6], particularly in relation to consumer protection and the prevention of overheating
- Ensure through planning requirements and coordination that public EV chargers adopt standardised connectors and open-access communication protocols to maximise accessibility and fully exploit smart charging to minimise grid impacts
- Undertake feasibility study on the cost effectiveness and potential co-benefits of a hydrogen backbone and full hydrogen grid conversions, including how to prepare for and minimise disruption
- Continue to engage with C40 Cities and similar programmes to maximise the learnings and benefits from decarbonisation efforts both in London and internationally

This study demonstrates that there are several decarbonisation scenarios that London could follow to 2050. All are ambitious and will require significant and sustained policy effort, starting as soon as possible. The difference in cost between the scenarios is not sufficiently large to determine a clear preference at this stage, given the

[5] Such a retrofit scheme is likely to require action by the UK government, but GLA and the boroughs could play an important role in raising awareness and facilitating retrofit projects by bring together installers, investors and building owners to take advantage of national schemes and funding sources.
[6] *Heat Networks: Code of Practice for the UK*, CIBSE and ADE, 2015.

current uncertainties in scenario cost, impact and deliverability. The progress made and evidence collected in the next decade will be instrumental in determining London's long term pathway.

2 Introduction

2.1 Context

Meeting the targets committed to in the Paris Agreement, in order to limit the increase in global average temperature to well below two degrees above pre-industrial levels, will require deep decarbonisation of all sectors of energy use. Cities such as London have a pivotal role to play in achieving these objectives and must develop robust climate action plans.

There are a wide range of options available to decarbonise London's energy system; two of the key options are electrification of heat and transport or use of low-carbon hydrogen in the same sectors. Additional supporting options include the use of low carbon biomethane for gas grid injection, the use of district heating systems making use of waste and secondary heat in areas of high heat density, and deployment of solar PV for renewable electricity production. All the options outlined in this study have associated benefits and challenges, as described in this report. The policies in place, both nationally and locally, will be instrumental in determining the mix of technologies.

2.2 Objectives of this study

Element Energy was commissioned by C40 Cities Climate Leadership Group and the Greater London Authority (GLA) to undertake an analysis of decarbonisation pathways to inform London's strategy on energy and climate. This study provides insight into the technology options available for low-carbon heating and transport. It aims to give a clear analysis of four potential pathways to reduce London's emissions, and their implications for infrastructure and the wider energy system. The analysis includes the carbon and cost implications for each pathway, as well as highlighting the challenges and uncertainties associated with them. The results have informed London's five-year carbon budgets and will support energy policy decisions, highlighting key decision milestones.

This work builds on previous analysis on London's potential zero carbon pathways, which were set on an assumption that there will be residual emissions from aviation, industry and existing building stock. The London Environment Strategy[7] commits to addressing these residual emissions through emissions offsetting or negative emissions technologies (such as carbon capture and storage) to reach zero carbon. This study aims to provide further insights into the possible 2050 outcomes, by identifying policies, programmes and decisions that can drive the transition. It is also critical to understand key actions and decisions to be taken in the near term to ensure London can meet its climate goals, including potential requirements for the safeguarding of land or assets. Finally, the study provides a summary of low regrets actions for the 2020s that are common to all pathways.

[7] *London Environment Strategy*, Greater London Authority, May 2018

2.3 Scenarios

Five scenarios have been developed to build a picture of how London’s energy system may look in 2050 under differing pathways. The key themes of the scenarios are summarised below in Figure 2-1.

Figure 2-1 Scenario narratives and principles

Baseline (with High energy efficiency uptake)
Baseline scenario represents the likely outcome with minimal change to current policies on low-carbon technologies, with the exception of energy efficiency, for which the same high level of uptake is applied as for all scenarios. There will be a relatively low uptake of most low carbon technologies beyond 2025.

Decentralised
The Decentralised scenario promotes Decentralised energy production and distribution. This results in high uptake of heat networks and solar PV, as well as some additional decarbonisation through blending of biomethane into the gas grid.

High electrification
The High electrification scenario promotes electrification of heat and transport using an increasingly decarbonised electricity grid, with decommissioning of the gas grid by 2050. There will be high uptake of heat pumps and electric vehicles and a requirement for significant application of DSR and energy storage.

Decarbonised gas
The Decarbonised gas scenario promotes the conversion of London’s gas grid to 100% hydrogen by 2045. Heating remains predominantly gas (H_2) boilers, with some heat networks. Transport includes a large share of hydrogen fuel cell electric vehicles.

Patchwork
The Patchwork scenario aims to represent a more realistic, mixed pathway, avoiding options currently deemed too uncertain or bringing inappropriate risks or challenges. It encompasses aspects of all the above scenarios to meet carbon targets.

The scenarios have been developed to concentrate ‘ambition’ (and the level of policy effort) on different decarbonisation options in each case. For example, the Decentralised scenario concentrates primarily on driving district heating deployment, the High electrification scenario focusses on supporting the uptake of heat pumps and electric vehicles, while the Decarbonised gas scenario is directed towards addressing the infrastructure challenge of a switchover of the natural gas grid to hydrogen. It is then interesting to compare the levels of decarbonisation reached in each scenario, as well as the associated costs, as an indication of the effectiveness of the technologies deployed. However, these figures should not be considered in isolation, as there are varied and important risks and uncertainties associated with each scenario, which will also have a significant bearing on the policy decision of which pathway(s) to support.

3 Decarbonisation options and supporting policies

In this section, a range of technology options with the potential to lead to substantial decarbonisation of London's energy system are presented:

- Energy efficiency measures[8]
- Heat networks (including utilisation of CHP and waste heat through large heat pumps)
- Heat pumps (HP), hybrid heat pumps (HHP) and direct electric heating
- Biomethane and bio-SNG for grid injection
- Hydrogen
- Solar PV and solar thermal[8]
- Battery electric vehicles (BEVs)
- Hydrogen fuel cell electric vehicles (FCEVs)
- Plug-in hybrid electric vehicles (PHEVs)

It should be noted that biomass boilers have not been included due to air quality concerns[9], and micro-CHP has not been included due to large uncertainty around cost-effectiveness. Energy storage and DSR are discussed further in section 5.3.

This study addressed the limits associated with these technologies in terms of their capacity to deliver decarbonisation. For example, heat networks are only economic in areas with a sufficiently high heat density, and heat pumps are only practical in homes with sufficiently high energy efficiency and no prohibitive constraints on available space.

In order to determine the potential level of uptake of each technology in London, and the policies that would be required to reach these levels, a literature review and series of stakeholder consultations were conducted. The stakeholders who provided input to the study are shown in Table 3-1, along with the key topics of discussion.

Literature Review of Policies & Programmes

Understanding of barriers and policy effectiveness.

Evidence of deployment rates, policy/deliver mechanisms and costs.

Stakeholder consultations

Canvas opinion and information on a broad range of key topics and emerging technologies.

Learning from other cities on powers, policies and implementation.

Existing reports & projections

Use modelling and data from a broad range of sources to inform our modelling:

- Uptake projections
- Spatial information
- Carbon estimates
- Cost figures

[8] The work around energy efficiency measures and solar thermal deployment was completed as part of Work Package 2 of London's Climate Action Plan, led by Arup. The results have been incorporated into this study as the buildings inputs, primarily energy demand figures and solar thermal.
[9] *London Environment Strategy*, Greater London Authority, May 2018

Table 3-1 Summary of stakeholders consulted during this project

Organisation	Topic
National Grid	Gas network scenarios
	Isle of Grain
Transport for London	Transport scenarios
Cadent	Gas network scenarios
UK Power Networks	Electricity distribution infrastructure impacts and planning
SGN	Gas network scenarios
Orange Gas	Transport scenarios
Certas	Transport scenarios
Vattenfall	District heating scenarios & Amsterdam case study
Cities	Manchester case study
	Bristol case study
	Toronto case study
	Gothenburg case study
	Seoul case study
UCL	Energy system scenarios

3.1 Energy efficiency in buildings

Energy efficiency measures, such as cavity wall insulation or installation of low energy lighting reduce the energy demand, and therefore fuel costs, in a building. The energy efficiency analysis for this project was completed by Arup in an earlier work package[10]. The outputs of the energy efficiency work have been used as energy demand inputs to this study, with Energy Performance Certificate (EPC) ratings being one of the key energy efficiency criteria.

Energy saving measures considered in the Arup analysis are promoted by policies such as:

- Local government-initiated programmes similar to RE:NEW and RE:FIT to support sub-groups of the market in most need of support e.g. fuel poor, social housing, public sector and SMEs.
- Fiscal incentives such as stamp duty, council tax and business rates variation according to EPC rating.
- Introduction of MEES to achieve EPC rating C
- European market-initiated minimum energy performance standards on appliance products and lighting.

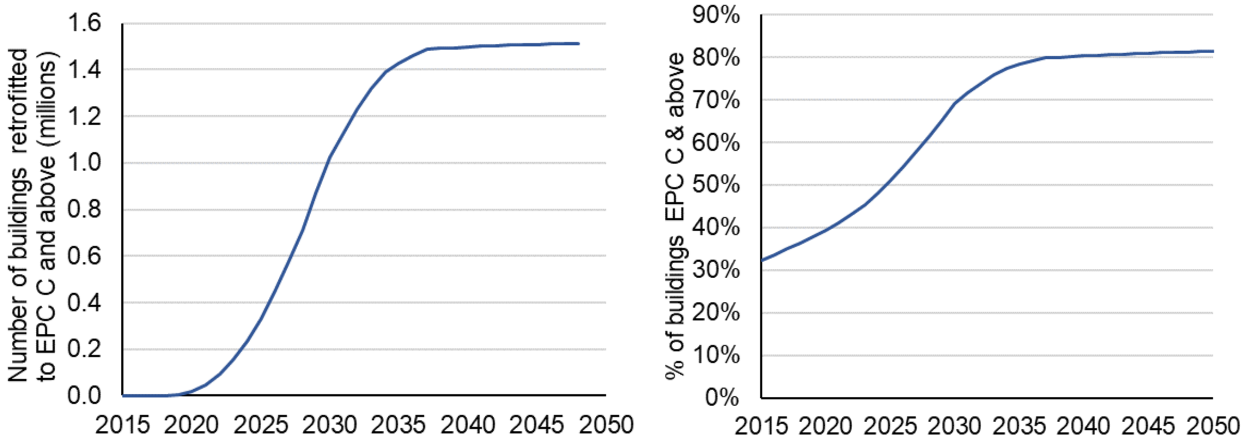
This study assumes the same level of energy efficiency retrofit, the Arup central scenario[10], across all the scenarios, including the Baseline scenario, to isolate the impact of low-carbon technologies. This was designed to represent an ambitious but achievable retrofit scenario, if significant policy effort is directed towards energy efficiency through a series of policy packages. It includes a 50% reduction in domestic appliance energy demand and an 80% reduction in domestic lighting energy demand per building by 2050[11]. The average heat demand of an existing property reduces by around 30% by 2050. The reduction in energy demand in existing buildings largely offsets the additional energy demand from new buildings, limiting the impact on London's energy infrastructure (discussed further in section 5.3). The cumulative carbon impact of reductions in building energy demand is higher when those reductions occur earlier. If the roll-out of energy efficiency retrofits is delayed into London's second carbon budget period (starting 2023), more buildings must be retrofit to reach the achieve the same cumulative carbon emissions in 2050. This delay would add £2.5 bn to London's total retrofit investment[10].

Energy efficiency measures should make a contribution to reducing energy and natural resource consumption, whichever pathway London ultimately takes. The energy efficiency measures therefore reduce the infrastructure investment required, helping to compensate for energy demand of new buildings.

In our analysis we have assumed that low temperature heating systems - heat pumps and district heating - would only be deployed in buildings with an energy efficiency of EPC C or better. The number of buildings retrofitted over time to EPC C or above, is shown in Figure 3-1 (left). The resulting proportion of buildings suitable for low temperature heating systems is depicted in Figure 3-1 (right).

[10] *London's Climate Action Plan*, Work Package 2: Building Retrofit Programme Assessment, Arup, 2018
[11] https://www.gov.uk/guidance/2050-pathways-analysis

Figure 3-1 Arup central scenario retrofit Left: Number of buildings retrofitted with energy efficiency improvements to EPC C and above. Right: Proportion of buildings in London suitable for low temperature heating systems (EPC C and above)



By 2050, around 80% of buildings in London have an EPC rating of C or above and are therefore suitable for low temperature heating systems. This level of efficiency uptake is the level deemed feasible in this Arup study[10], although the Clean Growth Strategy[12] has an aspiration that as many homes as possible are improved to EPC band C by 2035, where practical, cost-effective and affordable.

This proportion provides a limit for the total number of buildings with low temperature heating systems over time. The buildings remaining at EPC rating lower than C in 2050 are the hardest to decarbonise, with the only remaining low-carbon heat options assumed to be hybrid heat pumps, direct electric heating or hydrogen boilers.

3.2 Heat networks

Heat networks, or district heating systems, use centralised energy generation facilities to heat water and then distribute it through a network of pipes to serve multiple end users. One of the key advantages of heat networks over building scale technologies is that they benefit from the economies of scale and diversity of heat demand profiles across users. They can also more easily utilise waste heat sources, such as those from industry and environmental heat sources. Some sources provide the required temperature directly, while for others the source temperature is raised through the use of heat pumps before supplying heat to the network.

Heat networks are most cost-effective in areas of high heat demand density. This is because the high cost of the distribution pipework and energy generation centres can be shared between a larger number of users. Heat networks deployed in areas of high heat density, and using waste heat sources, have the potential to be more cost effective than other low-carbon alternatives. They also provide system flexibility through the diversity of heat demand, the ability to integrate significant amounts of thermal storage and the possibility (in principle) of using multiple heat sources whose dispatch can be optimised over time.

Heat networks are most efficient when combined with low temperature heating systems to reduce losses in hot water distribution and to increase the efficiency of heat generation where this involves heat pumps. The supply temperature assumed in this study is 45°C. Space heating at this temperature requires high energy efficiency standards, as discussed in section 3.1. Therefore, in this study, heat network connection has been limited to buildings which will have an energy efficiency rating of EPC C or better by 2050. Additional requirements for connection to heat networks are the installation of low temperature emitters (e.g. low temperature radiators), heat interface units (HIU) and heat meters. The HIU controls the supply of hot water to the building, and the heat meter measures and records the amount of heat supplied.

[12] *The Clean Growth Strategy, Leading the way to a low carbon future*, HM Government, 2017

Heat network barriers and challenges

Although heat networks can bring the benefits described above, there are many challenges and barriers associated with their implementation, such as:

1. High initial investment, long timeframes for construction and long payback times.
2. Demand uncertainty, which brings uncertainty over viability of investments.
3. Policy uncertainty and conflicts with incentives for other renewable heating technologies.
4. Natural monopoly if there is only one operator serving in a local area.
5. Consumer awareness, perceptions and confidence.
6. Requirement for coordination of multiple stakeholders including developers, customers, land owners, utilities and infrastructure developers.

As a result of these barriers, heat networks are difficult to implement without strong supporting policy and coordination. To define the limits of deployment, a literature review was carried out, combined with stakeholder consultations.

Heat network policies and policy packages

There are already some policies and programmes to support the development of heat networks in London, such as the Decentralised Energy Enabling Project (DEEP) and capital grants, such as those through the Heat Networks Investment Project (HNIP)[13]. Competition policy, improved customer protections, minimum technical standards and some form of price regulation are considered key measures that would help to ensure good value and quality of service consumers and thereby support further development of, and connection to, heat networks[14]. Planning policy and building regulations for new buildings can be particularly instrumental in encouraging the development of heat networks in areas with large communally-heated new developments, by bringing down the risk for network operators, and consequently investors. However, efforts should be made to ensure that the infrastructure is appropriately sized to allow for the future expansion of the network and the connection of existing buildings over time. Finally, in cities with extensive heat networks, such as Gothenburg, city planning or heat zoning has commonly played an effective role in creating efficient district heating systems with high connection rates. Within heat network zones, connection policy can ensure that the majority of consumers connect to the heat network in the long run, including existing domestic buildings. For example, in Paris, in a heat network zone all new builds must connect, and all existing buildings must connect, unless economically unfeasible.

Using information from the literature review and stakeholder consultations, three policy packages were developed to drive low (L), medium (M) and high (H) uptake levels as shown in Table 3-2. The low uptake policy package only includes the first three policies, supply side training, capital grants and waste heat incentives. The medium uptake policy package includes all policies presented, except a connection policy for existing buildings, which is more difficult to justify and implement in a free market. This connection policy for existing buildings, assumed in the high scenario, would not require immediate connection, but rather on heating system replacement where economic and feasible.

[13] Heat Networks Investment project, Department for Business, Energy & Industrial Strategy
[14] Heat networks market study, Competition Markets Authority, 2018.

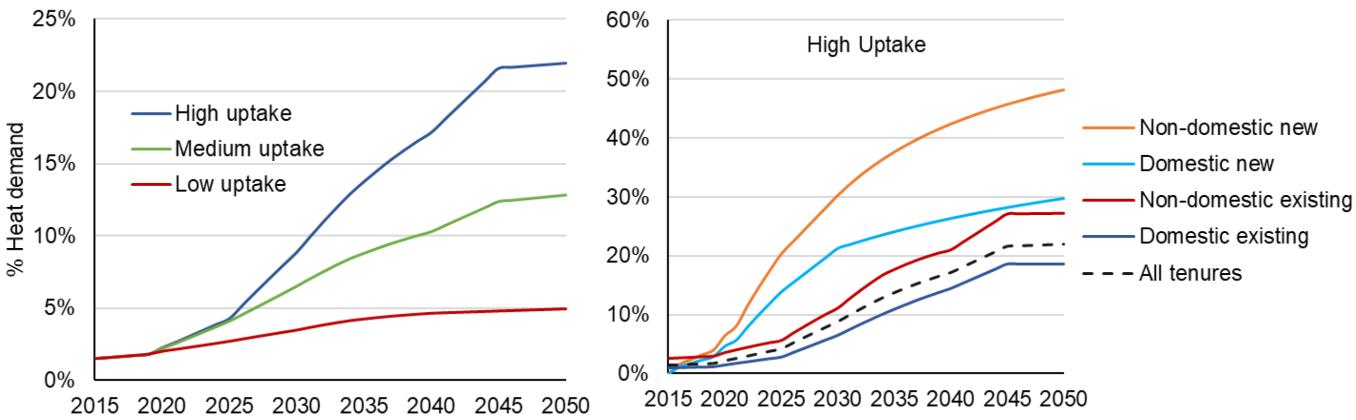
Table 3-2 Policies and policy packages to support heat network deployment

	Policy	Start	End	Policy Package
1	Supply side training, heat mapping and feasibility support	Present	2030	L, M, H
2	Financial - Capital Grants or loans	Present	2040	L, M, H
3	Financial - Waste heat incentives	Present	2040	L, M, H
4	Competition policy and price regulation	2020	2050	M, H
5	Building regulations - tightened max CO_2 for new build	2020	2050	M, H
6	Heat zoning - connection policy for new build	2022	2050	M, H
7	Heat zoning - connection policy for public buildings	2025	2040	M, H
8	Heat zoning - connection policy for existing buildings	2025	2050	H

Heat network demand and deployment

The heat network deployment trajectories over time for the low, medium and high uptake levels are depicted in Figure 3-2 (Left). Heat network uptake is restricted to relatively low levels until 2025 due to emerging market uncertainty and deployment timescales. To develop the deployment trajectories, the impact of the policy packages was specified for 26 building tenures, 12 domestic and 14 non-domestic, and the resulting heat network uptake was modelled spatially across the tenures. The tenures have been aggregated to domestic and non-domestic, existing and new, for the results, as shown in Figure 3-2 (Right, high uptake trajectory). The uptake for new build is higher than for existing buildings and there is higher uptake in non-domestic buildings, due both to the central location of many of the heat networks and to the lower barriers to connecting a smaller number of large non-domestic customers than a larger number of small domestic customers. It should be noted that the 'All tenures' trajectory, representing the share of total London demand across tenures, most closely follows the 'Domestic existing' trajectory, as this is the largest share of the demand.

Figure 3-2 Left: Proportion of heat demand served by heat networks in low, medium and high uptake trajectories. Right: Proportion of heat demand in each tenure served by heat networks in high uptake trajectory



A more detailed summary of the heat network deployment modelling can be found in the accompanying charts workbook[15].

[15] London's Climate Action Plan work package 3, accompanying charts workbook, Element Energy 2018

In this study, the GLA heat models[16] have been used as a basis for the spatial location of heat networks. Viable LSOAs (Lower Layer Super Output Areas) have been defined as those with a combined domestic and non-domestic heat density above a certain threshold, as given in Table 3-3. This table also gives the proportion of LSOAs viable for a heat network given the assumed heat density thresholds. The connection fraction is the average proportion of buildings connecting across the viable heat network areas (LSOAs). The connection fraction reflects the strength of connection policy applied, and is the differentiating factor between the medium and high uptake levels, which assume the same threshold heat density. The proportion of total London heat supplied resulting from the modelling is then presented in the final column.

Table 3-3 Summary of heat network deployment uptake trajectories

Uptake	Assumed threshold heat density kWh/m^2/yr	*Resulting proportion of LSOAs viable*	Assumed average connection fraction in viable LSOAs	*Resulting share of heat served in London*
Low	80	*14%*	27%	*5%*
Medium	50	*35%*	50%	*13%*
High	50	*35%*	73%	*22%*

Supply sources for heat networks

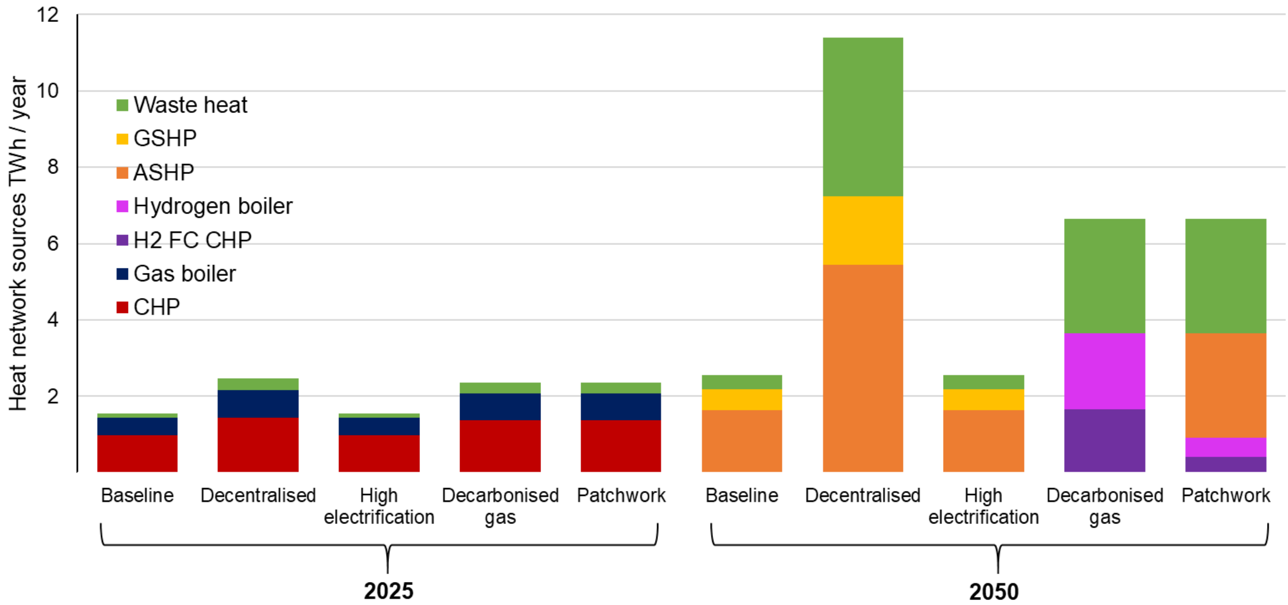
The GLA heat models[16] were also used to define potential sources of waste and environmental heat; the heat models use information from the Secondary Heat Study[17], with updates provided by the GLA. The high heat network uptake level in this study includes 4.2 GWh (36%) of heat provided from secondary sources a year, including industry and power station waste heat, heat recovered from building cooling and ventilation systems, heat from electricity grid transformers and sewer heat mining. These waste heat sources are generally recovered using a water-source heat pump (WSHP), to increase the temperature of the water before supply to the heat network. The supply sources for heat networks are allocated on the basis of which source is most economic in each area (MSOA - Middle Layer Super Output Area). The higher temperature waste heat sources are typically lower cost, due to higher efficiency of recovering the heat, and therefore these are allocated first.

Figure 3-3 shows a summary of the heat supply sources allocated in 2025 and 2050. Gas combined heat and power (CHP) is assumed to continue to be a significant source for heat networks in 2025. It has been the dominant fuel source in heat networks to date due to the improved efficiency over a conventional gas boiler of producing both electrical and heat output from the same fuel source. Air quality considerations will influence the location and emissions abatement technology required for CHP. By 2050, however, the use of natural gas is assumed to have been phased out due to its incompatibility with deep decarbonisation. The availability of low carbon hydrogen in the Decarbonised gas scenario allows the use of hydrogen fuel cell combined heat and power (FC CHP), as well as hydrogen boilers, over the longer term. These technologies replace some of the heat supply from heat pumps in 2050 and therefore reduce the impact on the electricity grid. The Patchwork scenario, with medium uptake of heat networks, contains some hydrogen in the supply mix due to the hydrogen backbone, as outlined in section 3.4. For more detail on the supply sources, please see the accompanying charts workbook[15].

[16] Heat demand and supply models, Greater London Authority, developed to model heat network potential in London

[17] Secondary Heat Study – London's Zero Carbon Energy Resource, April 2013

Figure 3-3 Heat network supply sources for all scenarios in 2025 and 2050.



3.3 Heat pumps, hybrid heat pumps & direct electric heating

Heat pumps

Heat pumps are a form of electric heating which extract energy from the environment (usually the air or the ground) to deliver heat with high efficiency. In this study we assume that all building scale heat pumps (HPs) are air-source heat pumps[18] (ASHP), which utilize heat in the outside air. The efficiency achieved increases with higher environment temperature and lower hot water output temperature[19]. The central case efficiency used in this study was 265%, based on real world UK trial data[20] for the seasonal performance factor (SPF). This allows them to achieve very low levels of CO_2 emissions when combined with decarbonisation of the electricity grid.

Heat pump barriers and challenges

Heat pumps operate more efficiently at lower output temperatures and therefore often require the installation of a low temperature heating system. Capital cost is one of the key barriers to heat pump deployment, with a typical domestic heat pump, of 7 kW, costing around £7000 to install, with a potential additional cost of around £3500 for a low temperature heating system, where new radiators are required. In addition, if the heat pump is used to supply both space heating and hot water, a hot water cylinder is often required. This leads to further costs if a storage cylinder is not already present, but also presents an important barrier relating to the space constraints in a typical household, and flats in particular. It should be noted that 'communal' heat pump systems, where a single heat pump serves a whole block of dwellings, have not been modelled (other than within heat networks) in this study, but they could play a role in mitigating the space and capital cost challenges of building-level heat pumps.

Further key challenges for heat pump deployment include the different heating experience for the consumer, relating to the lower supply temperature and the lower responsiveness of heat pumps relative to gas boilers. An additional challenge in the current UK market is overcoming consumer scepticism of a comparatively new technology and ensuring high quality installation. This is a common emerging market concern and has been addressed effectively in other countries with a more developed heat pump market, such as Sweden, with installer training and quality assurance (QA) schemes.

In buildings which do not have high enough thermal efficiency for a heat pump, alternative electric heating technologies include hybrid electric-gas heat pumps (HHP) and direct electric resistive heating.

Hybrid electric-gas heat pumps

Hybrid electric-gas heating combines a heat pump with a traditional gas boiler. The gas boiler is used at times of peak heat demand, primarily during the coldest periods and during other periods where hot water demand exceeds what can be provided by the heat pump. This reduces the requirement for high levels of energy efficiency (the building is not required to meet EPC C) and can negate the need for a hot water storage cylinder and low temperature heating system. It also means that a smaller heat pump can be installed if desired. The key benefits then are that the hybrid heat pump can be less costly, at around £6275 with no additional low temperature heating system cost, can reduce electricity consumption at peak times and can be installed in any building connected to the gas grid with only minor modifications. However, carbon reduction potential is also limited relative to an all-electric heat pump, due to the continued usage of natural gas. The effectiveness of HHPs, in terms of fuel cost, comfort and carbon reduction, is largely dependent on consumer behaviour, and the ability of 'smart' controls to influence this behaviour. This ensures that the share of the heat demand met by

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[18] Ground source heat pumps (GSHPs) are not modelled at the building scale in this study as the potential deployment in London is lower than for ASHPs. GSHPs may nonetheless have a role to play in certain suitable building types.

[19] *Hybrid Heat Pumps*, Department for Business, Energy and Industrial Strategy (BEIS), Element Energy, December 2017

[20] *Analysis of heat pump data from the renewable heat premium payment scheme*, UCL, 2017

the gas boiler is not larger than necessary and that the benefits of reduced electrical peak load are achieved. In this study, natural gas is assumed to be required to supply 15% of the heat output of the hybrid heat pump.

Direct electric heating

Direct electric resistive heating is an alternative electric heating technology, with a considerably lower capital cost of around £1200 for a domestic property, including installation, compared with around £7,000-10,000 for the heat pump and associated building upgrades. The key drawback of direct electric heating is that it is much less efficient than using heat pumps, with a maximum efficiency of 100%, compared with 265% assumed here for heat pumps. As a result, direct electric heating often leads to considerably higher consumer electricity bills, greater natural resource consumption and higher CO_2 emissions, when compared with heat pumps. Another concern is the high impact on the electricity grid, due to high electricity consumption at peak times. This is explored further in section 4.2. Nonetheless, direct electric heating is consistent with deep decarbonisation, provided it uses a very low carbon electricity grid. It can also be installed in the majority of the building stock without the need for deep energy efficiency improvements, although efficiency improvements may still be preferable to reduce ongoing energy bills. A hot water storage cylinder is typically required with direct electric heating, so there are also space constraints as for heat pumps.

Heat pumps policies and programmes

Using information from the literature review and stakeholder consultations, three policy packages were developed to drive low (L), medium (M) and high (H) uptake levels as shown in Table 3-4. The low uptake policy package only includes the first two policies: training and quality assurance, and extension of the Renewable Heat Incentive (RHI). The medium uptake policy package additionally incorporates capital grants, to tackle the barrier of high capital costs, and tightening of the CO_2 standards for new build. The high uptake policy package is very ambitious to allow a High electrification scenario that meets the carbon targets without the need for low carbon gas. Particularly noteworthy is the fact that this high uptake package relies on strong building regulations, including mandates for heat pumps in all new buildings and tight CO_2 standards for heating system replacements to exclude natural gas boilers.

Table 3-4 Policies and policy packages to support heat pump deployment

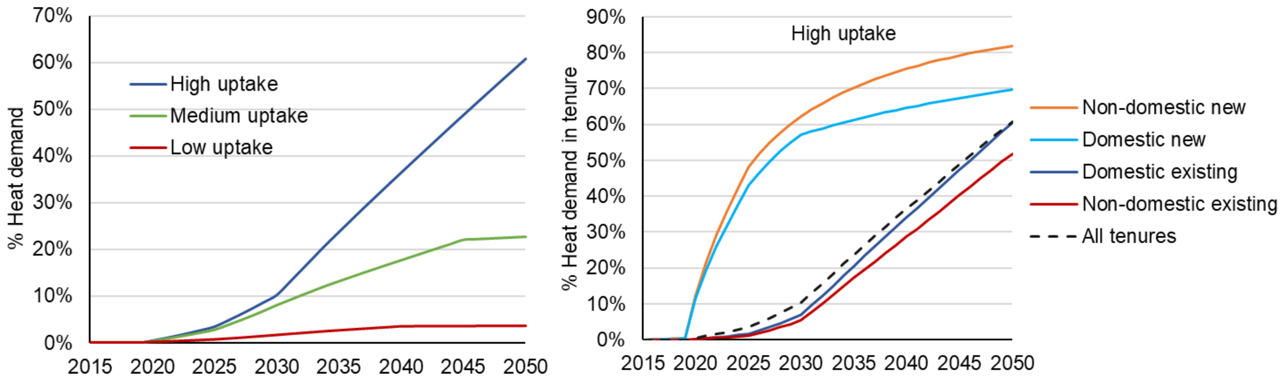
	Policy	Start	End	Policy Package
1	Installer training, quality assurance schemes & information campaigns	Present	2030	L, M, H
2	Financial - Extension of the RHI beyond 2020	Present	2040	L, M, H
3	Financial - capital grants	2025	2035	M, H
4	Financial - loans and social finance	2025	2050	H
5	Building regulations – tightened CO_2 standards for new build	2020	2050	M, H
6	Building regulations – CO_2 standards for heating system replacement	2030	2050	H
7	Building regulations – Mandate for HPs in all new buildings	2030	2050	H

Heat pump deployment

The heat pump deployment trajectories over time for the low, medium and high uptake levels are depicted in Figure 3-4 (Left). Heat pump uptake is restricted to relatively low levels until 2025 due to emerging market uncertainty in the UK and the time required to implement new policies.

To develop the deployment trajectories, the impact of the policy packages was specified for 26 building tenures, 12 domestic and 14 non-domestic, and the resulting heat pump uptake was modelled spatially across the tenures. The tenures have been aggregated to domestic and non-domestic, existing and new, for the results, as shown in Figure 3-4 (Right, high uptake trajectory). The uptake for new build is higher than for existing buildings, due to factors including the higher energy efficiency standards of new build, the greater ability to regulate deployment of heat pumps in new build as compared with the retrofit case, and the avoided cost of replacing the existing radiators with a low temperature system, which can be installed on building construction. It should be noted that the 'All tenures' trajectory, representing the share of total London demand across tenures, most closely follows the 'Domestic existing' trajectory, as this is the largest share of the total heat demand.

Figure 3-4 Left: Proportion of heat demand served by heat pumps in low, medium and high uptake trajectories. Right: Proportion of heat demand in each tenure served by heat pumps in high uptake trajectory



A more detailed summary of the heat pump deployment modelling results can be found in the accompanying charts workbook[15].The levels depicted are the desired uptake levels of heat pumps for incorporation into the decarbonisation scenarios. The deployment of hybrid heat pumps and direct electric heating will be described further in section 4.1.

3.4 Hydrogen

An alternative potential route to decarbonise heat and transport in London is the use of low-carbon hydrogen, delivered via a re-purposed gas distribution network. Hydrogen can provide heating using boilers similar to the gas boilers used in a majority of buildings in London, and can also be used in transport, in hydrogen fuel cell electric vehicles (FCEVs).

There are a range of potential benefits of this option, as described below. It is important to note, however, that significant uncertainties remain over the technical and economic viability of the widespread use of hydrogen for heating, and that this is not a proven technology. The uncertainties are also described further below. The efficiency and sustainability of use of hydrogen should also be considered and this is discussed further in section 5.2.

The potential benefits of hydrogen heating are that the building scale technology costs could be considerably lower than heat pumps (similar to the cost of gas boilers once produced at scale, around £2100), and hydrogen boilers would not necessarily require high levels of building energy efficiency. However, energy efficiency improvements may still be preferable to reduce ongoing energy bills and further reduce carbon emissions[21]. Hydrogen boilers could be implemented in all buildings connected to the gas grid, which is over 90% of London's building stock, and could be the low carbon heating option requiring least consumer behaviour change. The large-scale use of hydrogen leads to a lower electricity demand than that required where high levels of heat pumps and electric vehicles are deployed; the impacts on the electricity grid are discussed in section 5.3.

[21] This comparison has not been quantified in this study; the same high level of energy efficiency is assumed in all scenarios

Production methods

The most cost-effective source of bulk low carbon hydrogen is likely to be steam methane reforming (SMR) with carbon capture and storage (CCS) to reduce the carbon intensity of the hydrogen produced[22]. SMR uses a natural gas feedstock, reacted with steam under high pressure, to produce hydrogen. Electrolysis using low-carbon electricity could play a role, particularly for hydrogen for transport, where the price commanded can be higher, and the production could be more local.

The key assumptions used in this study are summarised in Table 3-5, along with characteristics of each of the major production methods. The input fuel for electrolysis is electricity, while for SMR it is natural gas.

Table 3-5 Major hydrogen production methods: key assumptions and characteristic

Method	Cost	Carbon Intensity	Assumed generation cost p/kWh[23]	Production efficiency kWh input / kWh H_2		Technology readiness
				2015	2050	
Electrolysis from grid	High	Depends on grid	6.9	1.59	1.07	Medium
Electrolysis from renewables	High	Low	6.9	1.59	1.07	Medium
SMR	Low	High	3.3	1.36	1.22	Medium
SMR + CCS	Low	Low	3.4	1.36	1.22	Low

Hydrogen production from SMR leads to CO_2 emissions which can be captured relatively easily. Capture facilities are assumed here to remove 90%[22] of the CO_2 emissions from the flue gas. The CO_2 emissions are then assumed to be transmitted to the shoreline terminals, compressed and transmitted via offshore pipelines to the offshore CO_2 storage sites. The location of hydrogen production and transport infrastructure is discussed in section 6.2. For more information on the hydrogen production methods assumed in each scenario, please see the accompanying charts workbook[15].

Challenges and uncertainties

There are many challenges and uncertainties associated with using hydrogen for heat and transport in London. One of the largest challenges is the infrastructure undertaking of repurposing London's current natural gas distribution network for hydrogen. Pipelines that are not suitable for hydrogen, such as iron-based pipes, must be replaced; the Iron Mains Replacement Programme is already contributing to this upgrade work. Gas meters are likely to require replacement, gas detectors may be required and there is expected to be a need for network surveying and pressure testing. Alongside this, is the need for consumers to replace their gas boilers, and potentially internal building pipework and appliances, in the same time period as the repurposing of the grid[22]. The commercial viability of producing large quantities of low carbon hydrogen is also uncertain. As noted above, the production methods currently deemed most viable at scale include SMR with CCS, which has not yet been proven commercially viable, and electrolysis, which is currently costly. Due to these factors, there remains significant uncertainty around the cost and deliverability of this pathway for London and nationally.

There are also concerns around the safety of distribution and use of hydrogen in buildings, and the associated consumer acceptability challenges. Trialling and demonstration projects are underway to understand the feasibility of large scale hydrogen use for heat and transport, in terms of cost, safety and distribution requirements[24]. Element Energy has recently undertaken research for BEIS on the supply chain of hydrogen

[22] *Hydrogen for heat technical evidence and modelling project,* (pending publication), a report by Element Energy, Jacobs and BGS for BEIS

[23] Source 1: *A greener Gas grid, what are the options*, SGI Imperial, July 2017. Source 2: *Options for producing low-carbon hydrogen at scale*, Royal Society.

[24] *Hydrogen for Heat Programme*, BEIS, Arup, Kiwa Gastec, 2017-2021

for heating, including production, transmission, distribution and storage[25]. The analysis and assumptions in this study are based largely on the datasets developed in that work. The cost of repurposing the gas distribution grid in London was estimated in the BEIS study to be £2.3 billion. We have included an additional £0.6 billion for transmission grid repurposing, calculated as London's 'fair share' of the national transmission grid repurposing cost (estimated in the BEIS study as £5 billion) based on the current share of national gas demand.

Patchwork scenario hydrogen backbone

In the Patchwork scenario, a 'backbone' hydrogen grid is built to supply some of the largest users, without repurposing the existing gas network. The objective of this backbone is that a significant amount of natural gas use could be replaced with low-carbon hydrogen, but at a fraction of the cost of full hydrogen conversion. The large users assumed to be connected to the hydrogen backbone include:

- 60% of large industry, allowing 45% industrial demand to be served by hydrogen.
- 25% of heat network heat supplied through hydrogen FC CHP or hydrogen boilers.
- Some transport depots and hydrogen refuelling stations, enabling hydrogen FCEVs to compose around 37% of total vehicles by 2050.

A detailed spatial assessment of the length of pipework required for the hydrogen backbone, and the associated cost, is outside the scope of this study. The cost of the backbone infrastructure implementation is assumed to be £297 million, based on the Cadent Liverpool-Manchester study[26]. This represents the capital costs, including transport of hydrogen and CO_2, as well as CCS infrastructure; it excludes hydrogen production, which is assumed to be costed in the retail price of hydrogen. It should be noted that this hydrogen backbone would require a high level of coordination to overcome the challenges of planning permission and constructing new infrastructure in such a dense urban environment.

As a sensitivity on the Patchwork scenario, due to the higher uncertainty around hydrogen deployment, a version is considered that does not include the hydrogen backbone. A discussion of this sensitivity is presented along with the results of the Patchwork scenario in section 5.

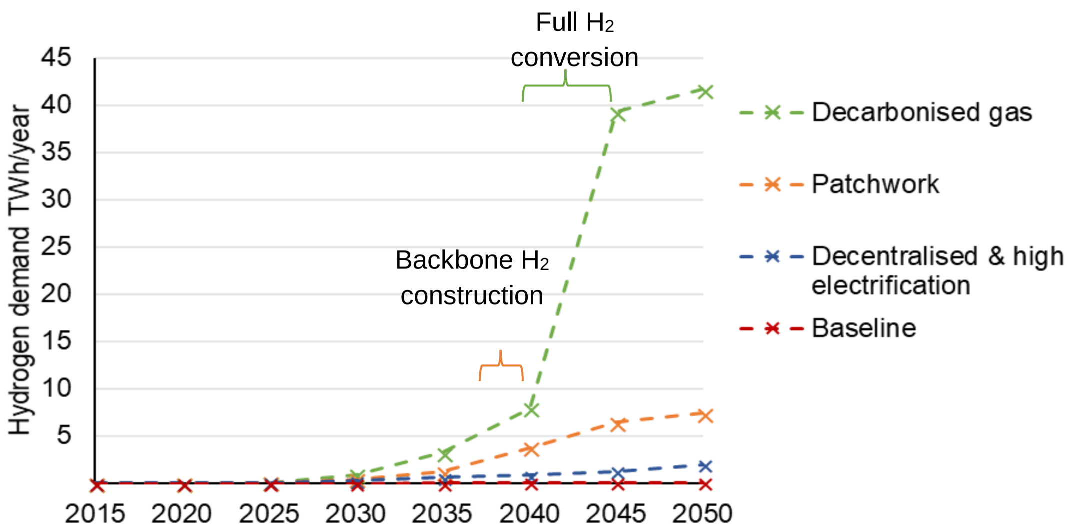
Level of hydrogen deployment

The total quantity of hydrogen consumed in each scenario is represented in Figure 3-5. In the Decarbonised gas scenario, hydrogen is used widely by 2050 for both heating (82% heat demand, in building scale boilers and heat network energy centres) and transport (82% road transport demand, in hydrogen fuel cell vehicles). In the Patchwork scenario, there is moderate hydrogen usage, as described above, through the hydrogen backbone, as well as blending of 7% hydrogen (by energy) into the gas grid. In the Decentralised and High electrification scenarios there is minimal hydrogen usage, purely for 29% of transport demand where longer range is needed, and this reduces to just 4% of transport demand in the Baseline scenario.

[25] *Hydrogen for heat technical evidence and modelling project,* (2017), a report by Element Energy, Jacobs and BGS for BEIS

[26] *The Liverpool-Manchester Hydrogen Cluster: a Low Cost, Deliverable Project*. Cadent, Progressive Energy Ltd, 2017

Figure 3-5 Hydrogen demand in London in each of the scenarios to 2050



Key hydrogen assumptions

Taking into account discussions with stakeholders from organisations including Cadent Gas, SGN and National Grid, the key assumptions made here in relation to hydrogen deployment in London are as follows:

1. London would be unlikely to be the first city to transition to a hydrogen gas grid, due to the additional cost of repurposing the gas network in such a dense urban environment, the likely locations of CCS operations and the existence of potentially more suitable industrial clusters elsewhere.
2. London would not transition to hydrogen (either fully as in the Decarbonised gas scenario or through a 'backbone' as in the Patchwork scenario) without the availability of CCS nationally, allowing large scale SMR + CCS production of hydrogen. The earliest date by which CCS is deemed to be commercial viable at scale is around 2035. In the Decarbonised gas and Patchwork scenarios, CCS is assumed to be available nationally from 2035.
3. The repurposing of London's distribution gas grid would take at least 5 years. Given the above constraints, this would be unlikely to begin until 2040.
4. For deployment of hydrogen for heating from 2040, a decision would need to be made on widespread roll-out of hydrogen for heating by around 2025 to allow time for technology development of large-scale hydrogen production, CCS and the end-use appliances, and to plan for gas grid repurposing.
5. High uptake of hydrogen in transport (82% transport energy demand), through fuel cell electric vehicles, would only occur in the presence of a full, or partial, hydrogen gas grid. With no hydrogen grid, there would only be limited uptake of hydrogen in transport (assumed to be 29% of transport energy demand) due to competition with battery electric vehicles, as detailed in section 3.6.
6. Blending of hydrogen into the gas grid is limited to approximately 20% by volume, and 7% by energy, as the assumed technical feasibility limit for current appliances. Blending would begin in 2035 in the Decarbonised gas scenario and 2040 in the Patchwork scenario, once national hydrogen and CCS is established, and production volumes increase.
7. Due to the low cost of heating fuel relative to transport fuel, hydrogen would only be used in significant quantities for heating where large-scale, low cost production methods are available – here, we assume predominantly through SMR + CCS.

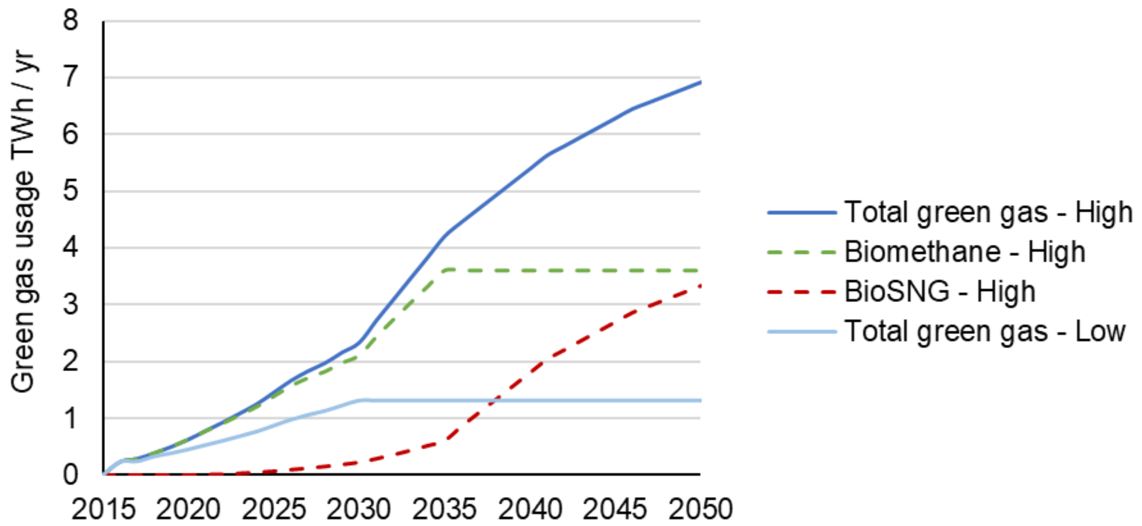
3.5 Green gas blending

The green gases considered in this study are biomethane and bio-synthetic natural gas (bio-SNG). Both are composed of methane (after removal of any impurities) and are hence chemically identical to natural gas, and so can be blended into the gas grid in any fraction. Biomethane is produced through anaerobic digestion of various forms of organic waste, often from agriculture, food or industry. Bio-SNG is methane produced through gasification of biomass, typically forestry residues or crops, but also refuse derived fuels.

Literature estimates for the potential level of biomethane and bio-SNG production in the UK vary widely from 30 to 180 TWh / year by 2050. For this study, the total level of green gas deployment is based on the National Grid Two Degrees Scenario from the Future Energy Scenarios 2017[27], which includes 59 TWh of green gas by 2050 nationally. The economic potential of biomethane is estimated to be around 30 TWh[28] of this, and is assumed to reach this limit in the 2030s. Based on London's current share of national gas demand, these levels equate to approximately 7 TWh green gas in London, of which 3.6 TWh is biomethane and the remainder is bio-SNG. Due to the limited availability of feedstocks in Greater London, this provides an upper limit to the green gas available. Literature values for the carbon intensity of these gases also vary widely depending on production method; the assumptions used in this study are 0.07 $kgCO_2/kWh$ and 0.06 $kgCO_2/kWh$ for biomethane and bio-SNG respectively.

In the Decentralised and Patchwork scenarios, high levels of green gas (7 TWh) are deployed, as there is still significant gas usage in 2050. Green gas deployment is assumed to stay at low levels for the remaining scenarios. These trajectories are shown in Figure 3-6, along with the split of biomethane and bio-SNG in the high uptake level. We have assumed biogas is only used for gas grid blending, rather than for transport.

Figure 3-6 Green gas usage for Low and High trajectories. Dotted lines represent the share of biomethane and bio-SNG (together accounting for all green gas) in the High trajectory.



[27] *National Grid, Future Energy Scenarios*, July 2017
[28] *Future Role of the Gas Network in Decarbonisation of Heat and Transport*, Cadent BEIS, 2018

3.6 Transport

The two primary methods consistent with deep decarbonisation of the transport sector are electrification and hydrogen. The Mayor's Transport Strategy (MTS), with supporting data provided by Transport for London (TfL), has been used as a basis for the transport policies and vehicle type deployment trajectories in this study. The MTS scenarios have been adapted to align with the fuel and infrastructure availability in the scenarios presented in this study. This section summarises the vehicle types included, the targets and policies driving transport decarbonisation, and the resulting fleet compositions in each scenario.

Conventional and electric vehicles

Conventional petrol or diesel vehicles use internal combustion engines (ICEs) to utilise the chemical energy in the fuels. Battery electric vehicles (BEVs) are entirely powered by rechargeable electric battery packs and an electric motor. Hydrogen fuel cell electric vehicles (FCEVs) combine hydrogen fuel with oxygen, to produce electricity to drive an electric motor. Electric vehicles (EVs) are typically more efficient that conventional ICEs, so have the potential to reduce natural resource consumption and improve the sustainability of London's energy system. This high efficiency generally makes EVs cheaper to run than conventional vehicles due to lower fuel costs. A summary of the typical efficiencies assumed is shown in Table 3-6[29].

Table 3-6 Comparison of fuel efficiency of conventional vehicles with BEVs and FCEVs

Method	Fuel	Typical efficiency MJ / km	
		2020	2050
Petrol ICE	Petrol	2.07	1.16
BEV	Electricity	0.62	0.44
FCEV	Hydrogen	0.91	0.68

When coupled with low carbon electricity or hydrogen sources, BEVs and FCEVs allow deep decarbonisation of the transport sector. They also produce no harmful tailpipe emissions, such as NO_x and particulates, so help to tackle air quality issues, which are particularly important in London.

However, there are still challenges and barriers to deployment of BEVs and FCEVs. A common concern over BEVs is the limited range; the typical range of a BEV is in the range 100 – 250 miles for a car, although this is predicted to improve in the coming years. Hydrogen FCEVs have a longer range and are commonly thought to be a more practical solution for heavier vehicles such as HGVs, although the capital cost is still substantially higher than BEVs. The capital cost of all forms of EV is still significantly higher than comparable ICE vehicles, although by 2024 the average 4-year cost of running an EV are predicted to match that of a petrol car[30]. For example, the cheapest available Nissan Leaf is priced at £27,290 (including VAT), compared with £13,280 for a similarly specified petrol Nissan Pulsar[31], although a Government subsidy of up to £4,500 is available to partially offset this premium. There is also significant behaviour change required for BEVs, as consumers must plug their vehicles in to charge, commonly for long periods overnight. Public EV charging infrastructure is still fairly limited, compared with the easy access to conventional fuel stations, however, over 80% of current EV drivers have access to a home charge point[32]. TfL is installing over 300 rapid charge points by 2020, to support EV uptake. The hydrogen FCEV market is less well developed in the UK, and hydrogen refuelling infrastructure is even more scarce than for BEVs, with 7 operational hydrogen refuelling stations (HRS) currently in London.

[29] *Low-carbon cars in Europe: A socio-economic Assessment,* European Climate Foundation, 2018
[30] *Low carbon cars in the 2020s, Consumer impacts and EU policy implications*, BEUC, Element Energy, 2016
[31] Prices provided by ComCar.co.uk
[32] *Ultra-Low-Emission Vehicle Infrastructure – What Can Be Done* RAC (2017)

Plug-in-Hybrid Electric vehicles

Plug-in-hybrid electric vehicles (PHEVs) contain an electric motor and also a conventional internal combustion engine (ICE). This gives the vehicle some of benefits of a BEV in terms of reduced carbon and tailpipe emissions (for the share of the time when using the electric motor) but allows switchover to the ICE for longer journeys when the battery capacity is insufficient, or during fast acceleration. It is assumed in this study that 70% of the energy use of the vehicle is electricity, while the remaining 30% is petrol or diesel[33]. It is expected that PHEVs will make a significant contribution to early EV adoption due to their flexibility and performance. Once BEV recharging stations are more widespread, there will no longer be the same need for PHEVs and the market share is expected to drop.

Bridging fuels

Bridging transport fuels are considered to be 'transition' fuels which could enable some reduction of carbon emissions before the technology and infrastructure to allow full transition to electric or hydrogen vehicles is fully developed. These include:

- Liquefied petroleum gas LPG (dual-fuel or hybrid)
- Bio-LNG / CNG (liquefied / compressed natural gas)
- Paraffinic fuels (including Gas-to-liquid GTL fuels)
- Biofuels (Hydrogenated vegetable oil HVO and biodiesel blends)

Under certain production methods, these fuels may allow a reduction in carbon emissions and tail-pipe pollutant emissions, such as NO_x. However, bridging fuels are not included in this analysis as the Mayor's Transport Strategy[34] focusses on achieving zero emission vehicles. For heavier vehicles, where BEV technology is not yet developed enough to provide a strong alternative to conventional ICEs, the short-term solution is assumed to be PHEVs.

Mayor's Transport Strategy aims and policies

Full details of the targets and policies can be found in the Mayor's Transport Strategy 2018.[34] The key aims of the strategy include:

- 80% of all trips in London to be made by foot, cycle or using public transport by 2041.
- All new black cabs to be zero emissions capable from 2018, all new private hire vehicles from 2023, all new buses from 2025 and all new cars and vans from 2030.
- London's entire transport system will be zero emissions capable by 2050.

The key policies supporting this transition are:

- The congestion charge, Low Emission Zone (LEZ), and Ultra Low Emission Zone (ULEZ)
- Support for electric charge points and hydrogen refuelling stations (HRS)
- All buses to be zero emissions capable by 2037
- End of sale of fossil fuel vehicles in 2040 (end of sales of cars by 2030, all vehicles by 2040)
- London wide Zero Emissions Zone by 2050
- Promotion of walking, cycling and public transport enabling more than 10% reduction in traffic by 2041

Electric Vehicle deployment

The Mayor's Transport Strategy contains two scenarios for projections of road transport and uptake of EVs. The Strategy uses the term zero emissions vehicles (ZEVs) to refer to both BEVs and FCEVs. In the Baseline

[33] Assumption provided by TfL to accompany TfL vehicle kms data
[34] *Mayor's Transport Strategy*, 2018, https://www.london.gov.uk/sites/default/files/mayors-transport-strategy-2018.pdf

scenario, the total distance travelled in road vehicles continues to increase and there is low uptake of all forms of electric vehicle. The MTS scenario, with the support of the policies above, reduces the annual vehicles kms through mode switch to walking and public transport, and reaches 100% ZEVs by 2050. A breakdown of the vehicle kms data for the two scenarios is shown in Figure 3-7, compared with the 2015 breakdown.

Figure 3-7 Mayor's Transport Strategy annual vehicle kms data

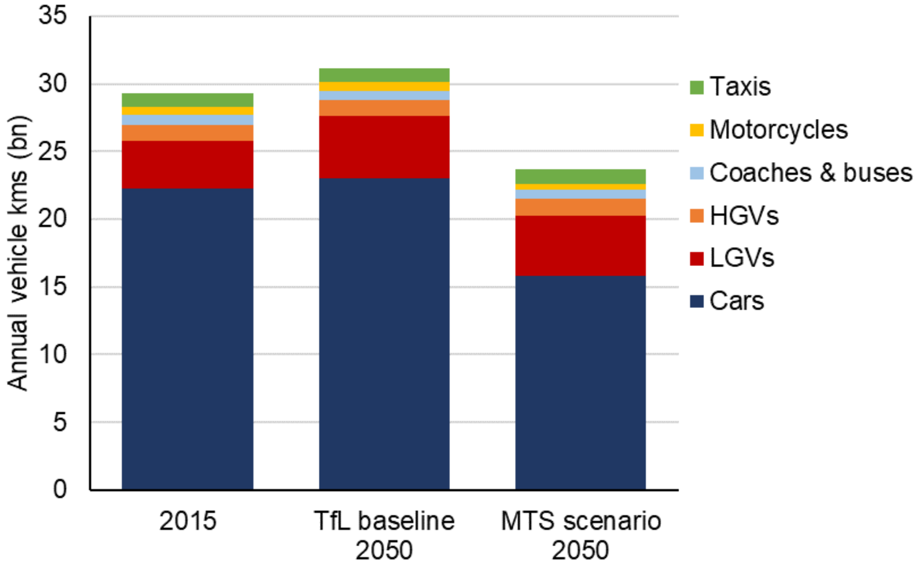
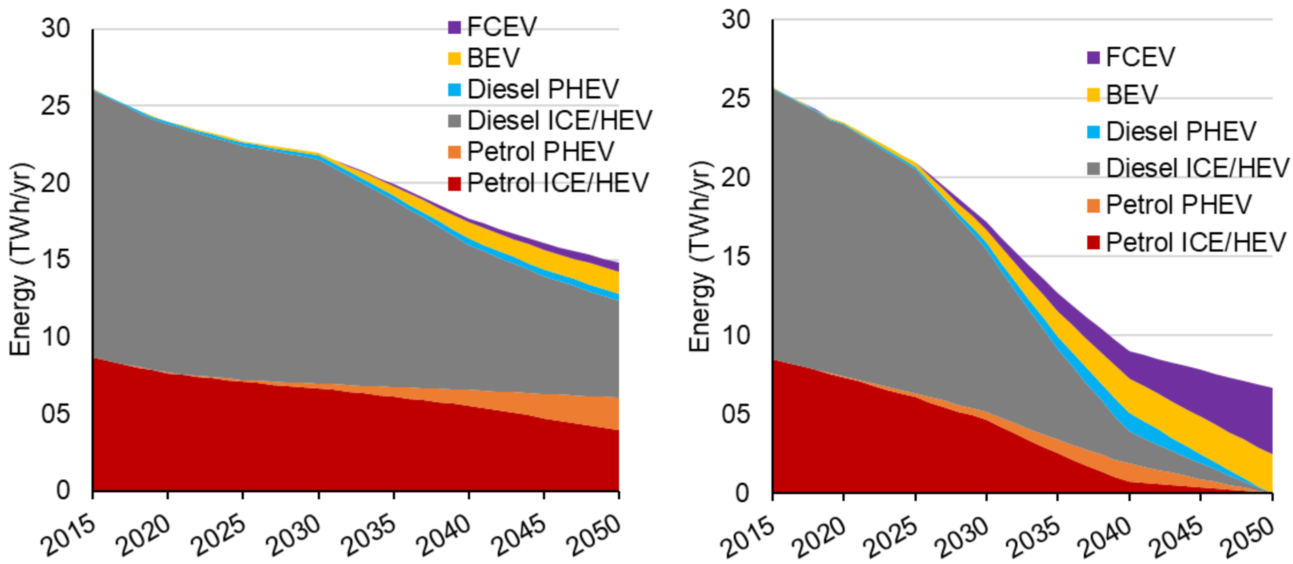


Figure 3-8 shows the uptake of PHEVs, BEVs and FCEVs over time for the TfL Baseline and MTS scenario. The large reduction in total energy consumed is a combination of the increased efficiency of electric vehicles and the mode switch in the MTS scenario. This leads to reduced fuel consumption and fuel cost in the scenarios relative to the Baseline.

Figure 3-8 Transport energy split by powertrain for TfL Baseline (left) and MTS scenario (right)



The Mayor's Transport Scenario was adapted for the four scenarios in this study by varying the proportion of BEVs and FCEVs making up the total share of ZEVs. Where there is high availability of hydrogen, the proportion of FCEVs was raised, such as in the Decarbonised gas scenario. Conversely, in scenarios with very limited hydrogen availability, such as the High electrification scenario, the fraction of BEVs was raised. This is depicted in Figure 3-9. The corresponding charging and refuelling requirements are discussed further in section 4.1.

Figure 3-9 Comparison of transport trajectory for High electrification scenario (left) and Decarbonised gas scenario (right).

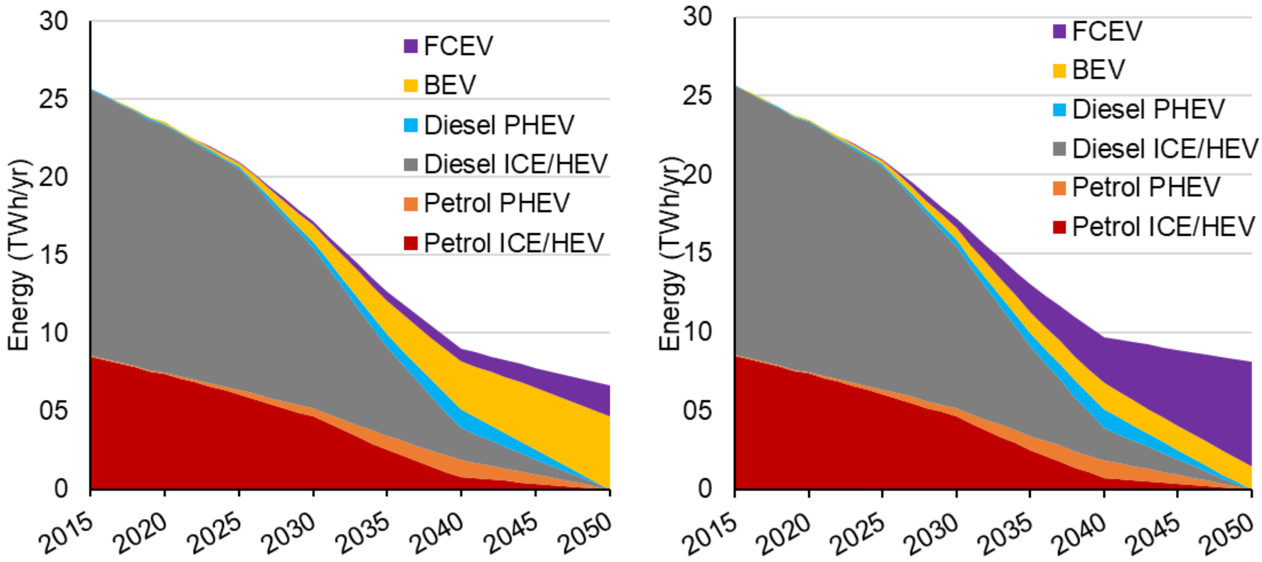


Table 3-7 shows the BEV and FCEV uptake in 2050 across the vehicle types for each scenario. Commercial vehicle owners make decisions based predominantly on the total cost of ownership (TCO), so the choice of vehicle is considerably influenced by the fuel cost. As a result, the FCEV fraction is very high for HGVs, LGVs and coaches in the Decarbonised gas scenario, where low cost hydrogen is available, and the FCEV fraction is low where hydrogen is produced through the more expensive electrolysis method, as in the High electrification scenario. Domestic car owners are influenced by a broader range of factors, such as convenience, image, and EV charge point availability, so the proportion of FCEVs to BEVs varies less by scenario; as a result, there are still significant FCEVs present in the high electrification scenario.

Table 3-7 Transport uptake of BEVs and FCEVs to 2050 by vehicle type for the scenarios. * BEVs present prior to 2050.

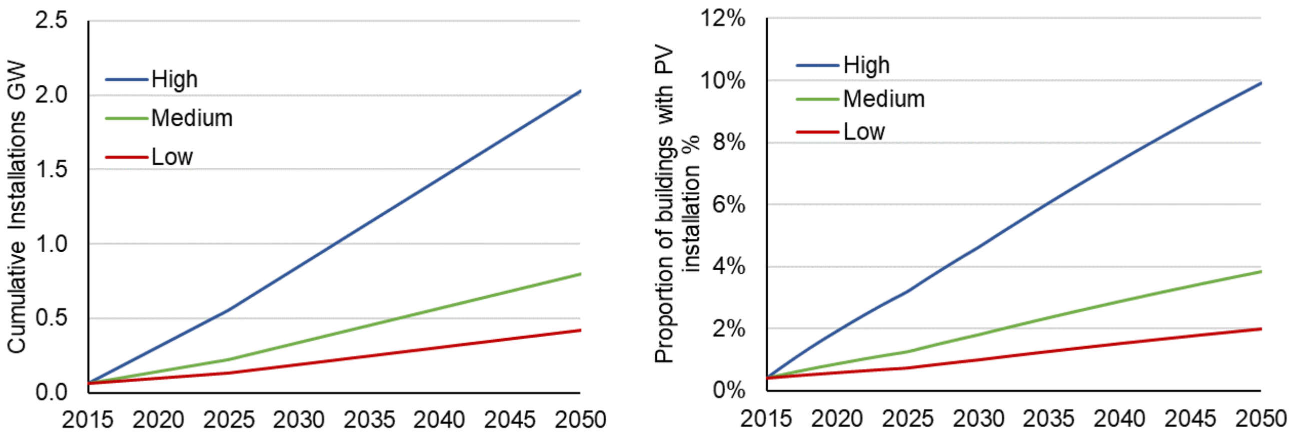
Scenario	MTS Scenario		Decentralised & High electrification		Decarbonised gas		Patchwork	
			No H_2 Grid		Full H_2 conversion		H_2 Backbone	
	BEVs	FCEVs	BEVs	FCEVs	BEVs	FCEVs	BEVs	FCEVs
Cars[35]	59%	41%	69%	31%	54%	46%	69%	31%
LGVs[35]	74%	26%	74%	26%	24%	76%	34%	66%
Rigid HGVs[36]	0%*	100%	80%	20%	0%*	100%	70%	30%
Artic HGVs	0%	100%	80%	20%	0%	100%	50%	50%
Coaches[36]	0%*	100%	80%	20%	0%*	100%	70%	30%
Motorcycles	100%	0%	100%	0%	100%	0%	100%	0%
Taxis[35]	100%	0%	95%	5%	30%	70%	75%	25%
Single deck buses[36]	100%	0%	95%	5%	10%	90%	75%	25%
Double deck buses[36]	100%	0%	90%	10%	10%	90%	50%	50%

[35] Defined based on results from the EE ECCo model.
[36] Defined based on *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target*, E4tech and UCL for CCC, 2015.

3.7 Solar PV and solar thermal

Solar PV deployment in London is included in this study as a renewable electricity generation method at the building scale. The low, medium and high trajectories used are those from the GLA solar model[37], which assesses the installation potential of solar PV, considering future changes in energy prices, cost of solar PV and deployment potential on a borough level. The trajectories are depicted in Figure 3-10.

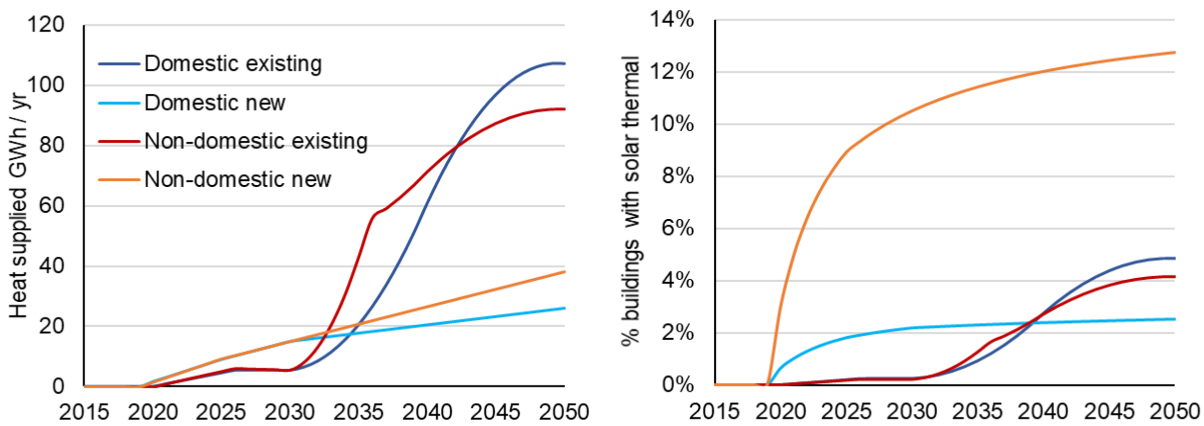
Figure 3-10 Solar PV uptake levels. Left: Cumulative MW of PV installed. Right: Proportion of buildings with a PV installation.



The electricity generated by solar PV is assumed to be primarily used within the building the PV panels are installed on, reducing electricity demand. Solar PV has the potential to contribute to the decarbonisation of London's energy system, by reducing electricity demand from national generation.

Solar thermal is a method of heating water using solar energy. Solar thermal systems are not usually the only heating system in the building, due to insufficient capacity of typical systems to meet the full heat demand and the variability of output with weather conditions. However, they can be used to reduce the fuel consumption of the main heating system. The solar thermal deployment in this project was modelled by Arup in work package 2[10]. Solar thermal was assumed to contribute 50% of the hot water demand of the building. The same level of solar thermal was incorporated into all five scenarios in this study, with the uptake levels depicted in Figure 3-11.

Figure 3-11 Deployment of solar thermal in all scenarios



[37] Solar model, Greater London Authority, Datastore.

3.8 Scenario development

Having defined the uptake levels of each technology, the scenarios were developed based on these. There was also some iterative scenario evolution through the modelling to improve and further differentiate the scenarios based on the results. Table 3-8 gives a summary of the resulting scenarios, followed by a description of some of the key assumptions behind them.

Table 3-8 Scenario definition through uptake of technologies by 2050

	Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Electricity Grid	Low	High			
	155 gCO_2/kWh by 2050	Falls to 28 gCO_2/kWh by 2050			
Energy Efficiency	High energy efficiency retrofit standards				
	81% of buildings EPC C or better, 50% appliance energy reduction, 80% lighting energy reduction by 2050				
Solar thermal	Arup central scenario				
	4% buildings, 0.26 TWh/year				
Heat Pumps	Low	Medium	High	Low	High
	<5% buildings	32% buildings	75% buildings	<5% buildings	75% buildings
Heat networks	Low	High	Low	Medium	Medium
	6% buildings	27% buildings	6% buildings	18% buildings	18% buildings
Green gas & Hydrogen	Low	Medium	Low	High	Medium
	1.3 TWh green gas	7 TWh green gas	1.3 TWh green gas, then gas grid decommissioned	100% H_2 gas grid conversion	7 TWh green gas + 7% H_2 blending + H_2 backbone
Solar PV	Low	High	High	Medium	Medium
	2% buildings	10% buildings	10% buildings	4% buildings	4% buildings
Transport	Low	High - 100% ZEV's by 2050			
	Tfl Baseline scenario	Tfl MTS Scenario with high BEVs	Tfl MTS Scenario with high BEVs	Tfl MTS Scenario with high H_2 FCEVs	Tfl MTS Scenario with selective H_2 FCEVs

The Decentralised scenario promotes decentralised energy production and distribution, supported by uptake of BEVs. As heat networks only reach 27% of buildings in this high uptake level, blending of biogas into the gas grid was used to reach deeper decarbonisation, along with medium heat pump uptake.

The High electrification scenario promotes electrification of heat and transport, leading to ambitious levels of heat pumps and BEVs, relying on strong policy support. It is assumed that in this scenario, the gas grid usage may drop so low that the grid is no longer financially viable by 2050. Therefore, all domestic and non-domestic heating is electrified by 2050, through heat pumps or direct electric heating.

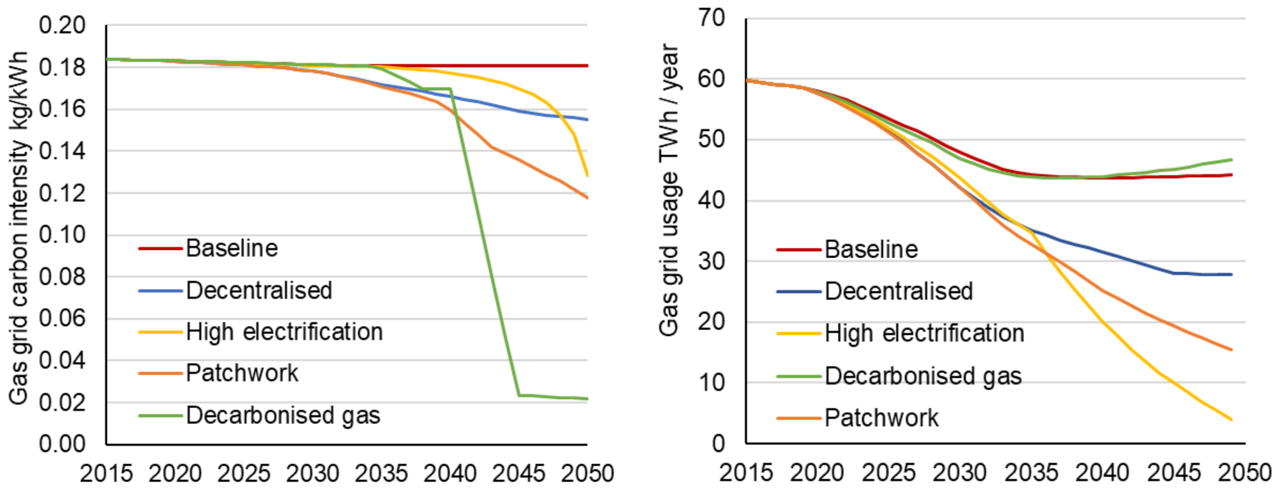
The Decarbonised gas scenario centres ambition around gas grid conversion to hydrogen, to supply both heat demand and a significant proportion of transport demand. There is therefore minimal requirement for heat pumps and energy storage, although BEVs still play a significant role in transport decarbonisation. This scenario relies on national momentum behind the widespread use of hydrogen and development of CCS. It should be noted that hydrogen for heating is assumed to be through the use of hydrogen boilers. An alternative option is hydrogen fuel cell micro-CHP (mCHP), which generates both heat and power. This could bring benefits of reduced requirement for electricity production and electricity grid capacity. Hydrogen fuel cell mCHP technology is still in the early stages of development and the capital cost is currently prohibitively high for most consumers. As such, there is considerable uncertainty as to whether hydrogen fuel cell mCHP will become sufficiently economic to form a significant contribution to London's energy system. The sustainability benefits of mCHP are studied in section 5.2 as a sensitivity on the energy and exergy analysis for the Decarbonised gas scenario.

The Patchwork scenario aims to incorporate many of the potential decarbonisation options. As can be seen in Table 3-8, it includes deployment of all technologies at a medium or high level. The Patchwork scenario evolved significantly through the course of the project, in order to meet the required level of decarbonisation with a mix of low-carbon technologies deemed most realistic and achievable. However, it should be noted that a high level of heat pumps is still required in this scenario to decarbonise heat sufficiently, despite high gas grid blending and medium heat network uptake.

Gas grid

The future of the gas grid is a topic of much debate[38,23]. To meet the carbon targets whilst maintaining substantial use of the gas grid, there must be significant decarbonisation through blending of green gas and/or hydrogen or full hydrogen repurposing. Figure 3-12 shows the future of the London gas distribution grid for the scenarios studied here, both in terms of carbon intensity (left) and usage (right). It is worth noting that the Decarbonised gas scenario sees gas grid usage increase relative to the Baseline scenario from 2040, due to the use of hydrogen in FCEVs as well as for heating. There is somewhat higher demand for natural gas as a feedstock for SMR in the Decarbonised gas scenario as well, however this would be through the high-pressure transmission grid, rather than the London gas distribution grid. In the Patchwork scenario, the gas distribution grid usage is lowered by the addition of the separate hydrogen backbone supplying some users. If the gas demand drops dramatically, the cost of operating and maintaining the grid would be spread over a smaller customer base; as a result, we have assumed that the gas grid would become unviable by 2050 in the High electrification scenario. It is worth noting that the drop in gas grid carbon intensity in the High electrification scenario in the 2040s is due to the reduction in gas demand, allowing green gas to make up a greater proportion.

Figure 3-12 Future of the gas grid to 2050. Left: gas grid carbon intensity for the scenarios. Right: Gas grid usage for the scenarios.

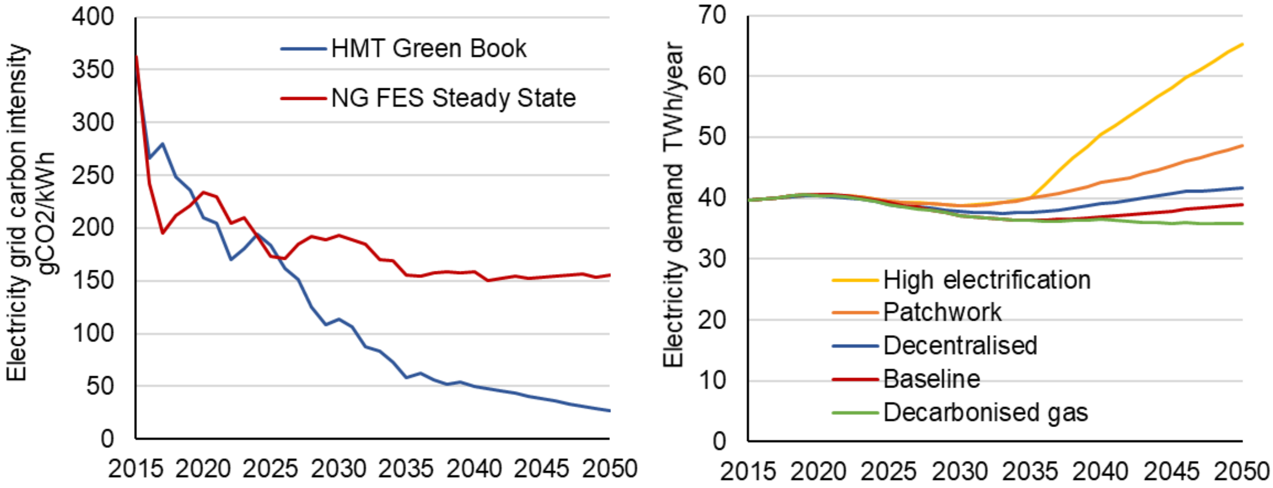


[38] *Next Steps or the gas grid, Future Gas Series: Part 1*, Carbon connect 2017

Electricity grid

It is assumed that the electricity grid decarbonisation and supporting policies are defined nationally. The carbon intensity projection for the Baseline scenario assumes that the grid remains above 150 gCO_2/kWh, as shown by the National Grid Future Energy Scenarios[27] (NG FES) Steady State trajectory in Figure 3-13. The other four scenarios are all assumed to decarbonised to less than 30 gCO_2/kWh by 2050, with the trajectory taken from the HMT Green Book[39]. This figure also shows London's total electricity demand for each scenario to 2050 (right).

Figure 3-13 Left: Electricity grid carbon intensity to 2050. Right: Electricity demand to 2050 for the scenarios.



[39] *The Green Book*, HM Treasury, Data tables

4 Method and Assumptions

4.1 Deployment and spatial distribution

Deployment modelling

The uptake of all technologies was combined to form a full description of London's energy system to 2050 for each scenario.

For transport, the proportion of the fleet of each vehicle type was combined with the vehicle kms and assumed efficiencies to calculate the transport sector energy use and emissions.

For the heat sector, the process of combining multiple heating technologies, along with the energy efficiency measures and limits, was more involved. As described in section 3.1, low temperature heating systems (here assumed to comprise all heat pumps and all heat networks by 2050) are limited to buildings suitable for low temperature heating, defined as those with an EPC rating of C or better. Buildings across the different tenure types, were allocated a heating system depending on the uptake levels composing that scenario, as well as spatial constraints such as heat network zones. The remainder of buildings with no low-carbon heating system, were allocated a gas boiler or direct electric heating in the proportions currently seen in London. Direct electric heating is allocated in the High electrification scenario to buildings which are insufficiently energy efficient for a heat pump and have not been connected to a heat network.

Industrial, aviation and non-road transport emissions were largely based on information from the GLA zero carbon model[40]. For industry, the energy required is assumed to stay constant to 2050, but with decreasing emissions, primarily due to electricity decarbonisation. Industrial gas usage was partially converted to hydrogen for the Decarbonised gas scenario (80% conversion) and the Patchwork scenario (60% of large industry only), therefore further reducing industrial emissions. Aviation, river and non-road mobile machinery (NRMM) figures are based on London Atmospheric Emissions Inventory (LAEI) projections to 2041, after which emissions are assumed to stay constant[41]. Rail emissions from diesel trains are assumed to decline to zero after 2030.

Spatial distribution

Uptake of all technologies was spatially mapped at LSOA level, to understand the infrastructure implications. The two most important spatial aspects of this project are the heat network distribution and the electricity grid upgrade requirements.

Heat network locations were first spatially defined through the GLA heat model[16], which defined viable LSOAs in each uptake level by a threshold heat density, as described in section 3.2. Next, the impact of the policy packages, assigned to the 26 tenure types, was used in combination with the spatial distribution of these tenures from the GLA building model[42], to project the uptake in each of the viable LSOAs.

The spatial distribution of the remaining heating technologies was required for input into the Element Energy GLA Power model, in order to estimate the electricity grid upgrades required spatially to 2050. This power modelling process is further explained in section 4.2. Heat pumps, hybrid heat pumps and solar thermal were spatially distributed by the remaining heat demand in each LSOA, split by 4 aggregated tenure types.
Direct electric heating was spatially distributed according to the current distribution in the GLA building model[42]. The remaining heat demand in each LSOA in each tenure was attributed to gas boilers. A summary of this modelling approach can be seen in Table 4-1.

[40] Zero Carbon Pathway Tool, Greater London Authority, Datastore
[41] London Atmospheric Emissions Inventory (LAEI), Greater London Authority, Datastore
[42] Buildings models, Greater London Authority, Datastore

Table 4-1 Summary of process of spatial distribution of heating technologies

Heating Technology	Spatial distribution
Heat Networks	GLA heat model and spatial distribution of 26 tenure types in GLA building model[42]
Heat Pumps, Hybrid HPs & solar thermal	Spread by remaining heat demand spatially in 4 aggregated tenure types after heat network allocation
Direct electric heating	GLA building model[42] spatial distribution
Gas boilers	Remaining heat demand in LSOA

For transport, the primary concern spatially is the electric vehicle charging infrastructure, due to the electricity grid impact. The Element Energy EV uptake model developed for TfL[43] distributes the uptake of EVs in the Greater London Area, based on indicators such as employment level, historic hybrid sales share, income and current EV uptake. A summary of the EV charge point infrastructure spatial distribution assumptions is present below in Table 4-2.

Table 4-2 Summary of process of spatial distribution of EV charging infrastructure

Charge point type	Spatial distribution
Home, public and work charge points	The Power Model distributes the EV charging based on the EE TfL model vehicle uptake spatial distribution including: a. - assumptions around journeys and workplaces b. - factors such as the availability of on street parking
Rapid charge points	650 locations determined by location of current rapid charge points and location of a subset of petrol stations and supermarkets chosen by distance from trunk roads.
Depot charge points for buses and HGVs	Location of TfL bus depots and existing HGV depots[44].

4.2 Power model and electricity grid

The electricity demand in London in each scenario has been forecast using the approach described briefly below.

Power modelling method

1. Assign level of technology uptake to each LSOA in London
2. Assign half-hourly electricity demand profile to each technology
3. Map LSOA demand to the London primary substations
4. Calibrate the predicted load in 2015 to match the observed winter peak on each primary substation according to UKPN 2014-2015 recorded data
5. Assess the increase in peak load on each primary substation and London-wide in five-year increments to 2050
6. Map the primary substation loads onto the connected secondary substations based on number of connections per secondary substation

[43] *Plug-in Electric Vehicle Uptake and Infrastructure Impacts Study*, Element Energy and WSP PB for TfL (2016).
[44] Government Vehicle Operator Licencing Service

7. Assess substation reinforcement requirements using predicted peak demands and UKPN Networks Data Tables on the headroom available on each primary substation. Secondary substations are assumed to have headroom to the next 500 kW increment.
8. Assess reinforcement to the transmission system and new generation capacity using the increase in London-wide peak demand

Peak reduction via Demand Side Response

The need for electricity system reinforcement and the resulting cost can be somewhat moderated using 'smart' devices that enable consumers to provide demand side response (DSR) at times when the electricity grid is constrained. DSR could also be deployed to provide other grid services at other times. The level of potential demand reduction is also estimated using the GLA Power model. The effectiveness of DSR is determined by the uptake of enabling technologies (e.g. smart thermostats or dedicated thermal storage), the number of consumers participating in each DSR scheme, and the technical potential for the load to be shifted without a reduction in the quality of service to the consumer.

The uptake of the DSR schemes[45] considered and their ability to shift electric heating (including heat pump) demand and electric vehicle demand[46] are presented in Table 4-3. These assumptions are based on a combination of DSR trial data and modelling.

Table 4-3 Level of DSR uptake and technical potential for the reduction of peak heat and EV loads

	2050 Domestic uptake	2050 Non-dom uptake	% Peak heat load shiftable without add. thermal storage	% Peak heat load shiftable with add. thermal storage	% Peak EV load shiftable
Static Time of Use tariff (SToU)	37%	37%	17%	80%	30%
Dynamic Time of Use tariff (DToU)	27%	27%	13%	80%	30%
Direct Load Control (DLC)	10%	10%	0%	100%	90%
On-demand (OD)	0%	10%	0%	100%	90%

Electricity system constraints can also be reduced by electricity storage in batteries. Network-scale batteries are able to access a number of revenue streams, including distribution network support, frequency response, grid balancing services, and reducing generation curtailment. The distribution network would not therefore bear the full cost of the installed storage capacity, but rather the network operator pays a price for peak reduction services sufficient to ensure storage availability at the required times. This price would be capped at the cost of competing reinforcement options. Similarly, batteries purchased by consumers, for example to increase on-site consumption of the electricity generated by a home solar PV installation, may assist in peak demand reduction as an ancillary benefit. The amount of battery storage likely to be available in future years to provide such services at a cost lower than other reinforcement options is highly uncertain and has therefore not been included quantitatively in this study.

[45] Level of DSR uptake defined by Element Energy based on Electricity System Analysis – future system benefits of selected DSR scenarios, EE and Baringa for DECC, 2012.
[46] Percent of peak load shiftable defined by Element Energy based on Time varying and dynamic rate design, The Brattle Group, 2012.

4.3 Investment

The investment required in each scenario was derived, including the cost of the component building-level technologies, fuel costs and infrastructure upgrade costs. A summary of the cost elements included in each of these categories is given in Figure 4-1.

Figure 4-1 Summary of cost elements included in investment modelling

Building Level technology costs

- Energy efficiency and heating systems
- Includes HIU & heat meter for DH
- Technology capex
- Technology installation
- Technology maintenance
- End of life replacement
- Smart home systems
- Storage costs

Infrastructure costs

- District heating
  - Energy centre
  - Network (pipes)
  - Capex, installation, maintenance & replacement
- Electricity grid infrastructure
- Gas grid infrastructure (repurposing to hydrogen)
- EV charging infrastructure
- Hydrogen refuelling

Fuel costs

- Retail fuel costs for all fuels
  - Natural Gas
  - Electricity
  - Petrol
  - Diesel
  - Hydrogen
  - Green gas
- Low and high sensitivities on all fuel costs

Key cost assumptions are presented in the Appendix. It should be noted that the inclusion of vehicle capital costs is beyond the scope of this project[47]. As the vehicle capital costs for BEVs and FCEVs are significantly higher than that of conventional ICEs, inclusion of vehicle costs would raise the cost of the four scenarios relative to the Baseline scenario.

Key investment modelling assumptions

The cashflow is presented in undiscounted terms and cumulative cost figures are calculated using a social discount rate of 3.5%[48]. Building level costs are attributed to the year of installation of the technology. The base year for costs is 2016/2017.

Heat networks: the cost is incurred primarily between 2025 and 2035 as it is assumed that the primary pipework and energy centres required must be built by 2035 to allow maximum connection. The secondary pipework cost is incurred in line with buildings connecting over time. District heating energy centre and heat distribution pipework costs are allocated to the infrastructure cost category in the charts presented; HIUs and heat meters, along with any other building-level costs associated with district heating, are allocated to the building level costs category.

Fuel costs: retail prices for electricity, natural gas, diesel and petrol are taken from the HMT Green Book[39], with domestic, non-domestic and industrial prices incorporated. Hydrogen and biomethane cost is related to the production method, with costs taken from literature[49] and converted to retail prices.

[47] Vehicle capital costs are not included as the focus of this cost analysis is on the energy infrastructure required to deliver decarbonisation of London's energy sector, and due to the large uncertainty around both the cost and number of electric and hydrogen vehicles by 2050 for the range of vehicle types included,
[48] HMT The Green Book, Central Government Guidance on appraisal and evaluation, Social time preference rate (STPR)
[49] SGI report, 'A Greener Gas Grid: What are the options?' Source 2, Royal Society: Options for producing low-carbon hydrogen at scale.

Transport: Hydrogen refuelling stations (HRS) are costed in line with the total hydrogen required for transport, based on an assumed HRS capacity of 500 kg/day. EV charging infrastructure is costed in line with the EV uptake as detailed below:

- **Home:** 0.8 home charge points per EV[50]
- **Work:** 0.2 work charge points per EV
- **Public:** 0.1 slow public charge points per EV
- **Rapid:** 650 rapids by 2025, then 300 BEVs per rapid charge point by 2050[29]
- **Depot:** 1 depot charge point per EV (HGVs, buses and coaches)

The hydrogen switchover in the Decarbonised gas scenario occurs from 2040 to 2045, with the cost of gas grid repurposing spread over 8 years, from 2038 to 2045.

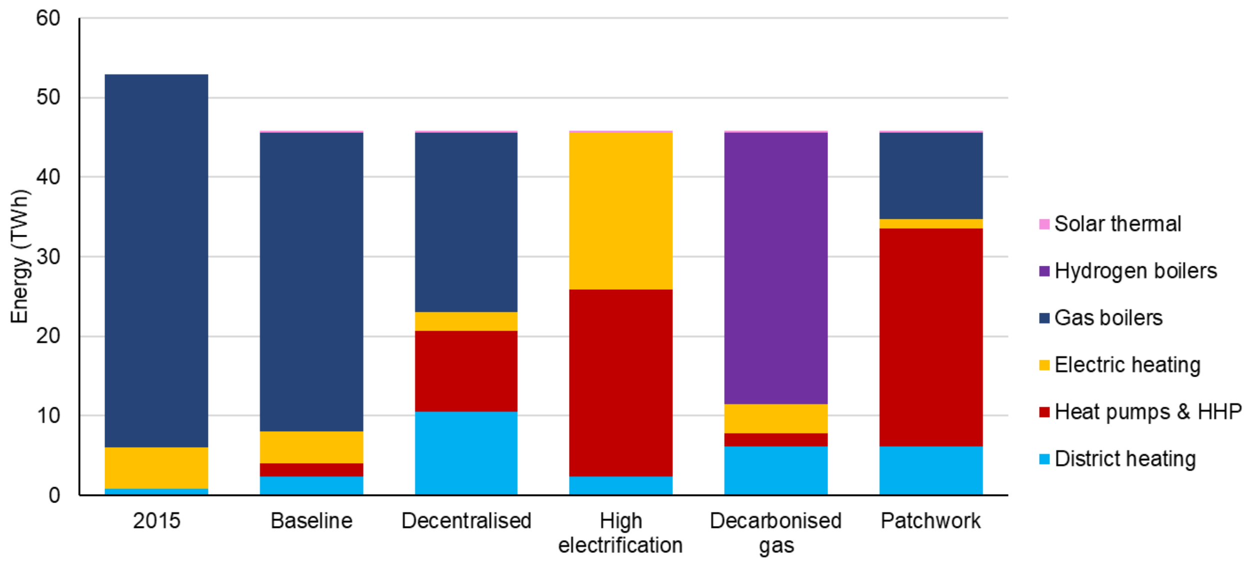
[50] Current UK average, Zap Map survey 2016

5 Scenario Results

5.1 Energy and Carbon

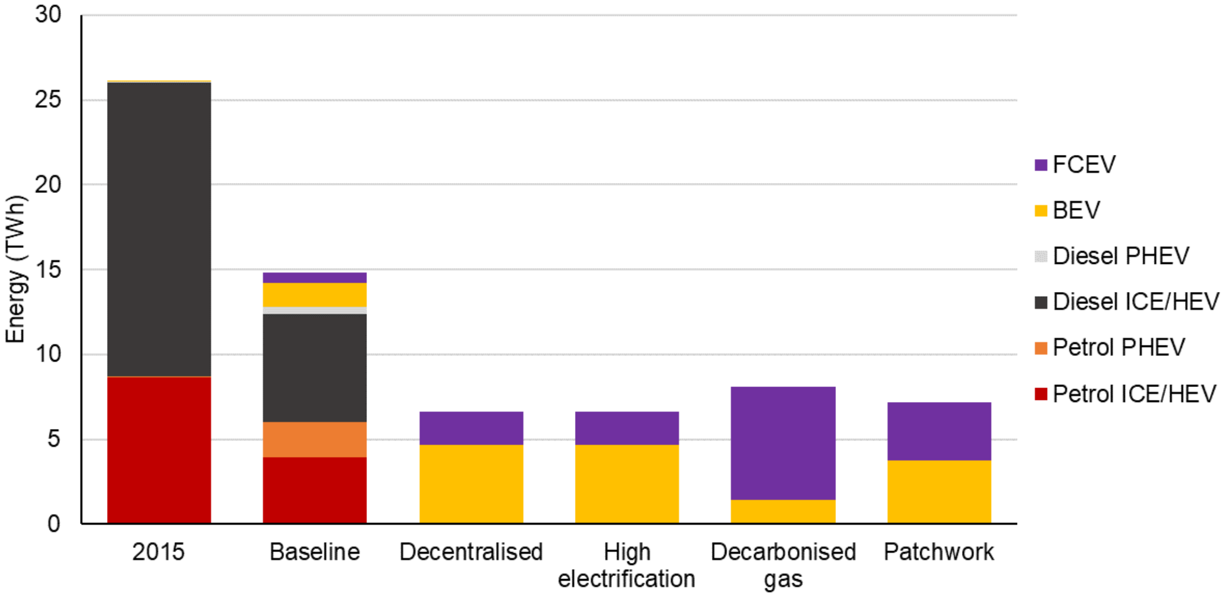
Figure 5-1 presents the energy used for heating by technology in 2015 and in each of the scenarios in 2050. The Baseline scenario sees low uptake of heat pumps and district heating, with gas boilers still dominant in 2050. Heat networks are deployed to around 25% of the building stock in the high uptake trajectory used in the Decentralised scenario, as heat networks only serve areas where there is sufficient heat demand density to make them cost effective. The Decentralised scenario therefore retains a significant amount of heating through gas boilers to 2050. Substantial decarbonisation of gas is required in the Decentralised and Patchwork scenarios, through deployment of biomethane and bio-SNG (7 TWh green gas total), which is deployed (at lower levels) in the other scenarios. High deployment of heat pumps and hybrid heat pumps in the High electrification and Patchwork scenarios allows deep decarbonisation of the heat sector. However, in the High electrification scenario, there is significant uptake of direct electric heating due to the assumption made in this scenario that the gas distribution grid is no longer viable in 2050, and heat pump uptake is limited by energy efficiency retrofit. The effect of direct electric heating on the electricity networks is discussed further in section 5.3 below. The Decarbonised gas scenario also almost entirely decarbonises the heat sector by 2050, primarily through hydrogen. The Patchwork scenario in 2050 relies on extensive deployment of heat pumps and hybrid heat pumps (HHP), supported by green gas and heat networks.

Figure 5-1 Heat demand met by each technology in 2050 in the five scenarios compared with 2015



The use of energy for road transport in 2015 and in each scenario in 2050 is shown in Figure 5-2. All four decarbonisation scenarios follow the Mayor’s Transport Strategy scenario, with the proportion of battery electric vehicles (BEVs) and hydrogen fuel cell electric vehicles (FCEVs) varying depending on availability and cost of hydrogen. The total energy demand for transport drops significantly due to both a reduction in vehicle use due to modal shift (shown previously in Figure 3-7), and the increased efficiency of electric and hydrogen vehicles over conventional vehicles. FCEVs are generally utilised more for heavy transport vehicles and only make up a large share of cars and light vehicles in the Decarbonised gas scenario due to the wide availability of low cost hydrogen.

Figure 5-2 Energy use in road transport by technology in 2050 in the five scenarios compared with 2015



Emissions results overview

The annual and cumulative emissions trajectories of the five scenarios can be found in Figure 5-3, with a summary of 2050 results in Table 5-1. All scenarios cut emissions dramatically relative to the Baseline scenario, reaching less than 10 $MtCO_2$ annually by 2050. It can be seen that the Decentralised scenario does not reach as deep a level of emissions reduction as the other scenarios by 2050, and that the Decarbonised gas scenario has higher cumulative emissions than the High electrification and Patchwork scenarios due to the relatively late switchover of the gas grid to low-carbon hydrogen from 2040.

Figure 5-3 Annual (left) and cumulative (right) emissions trajectories of the scenarios to 2050

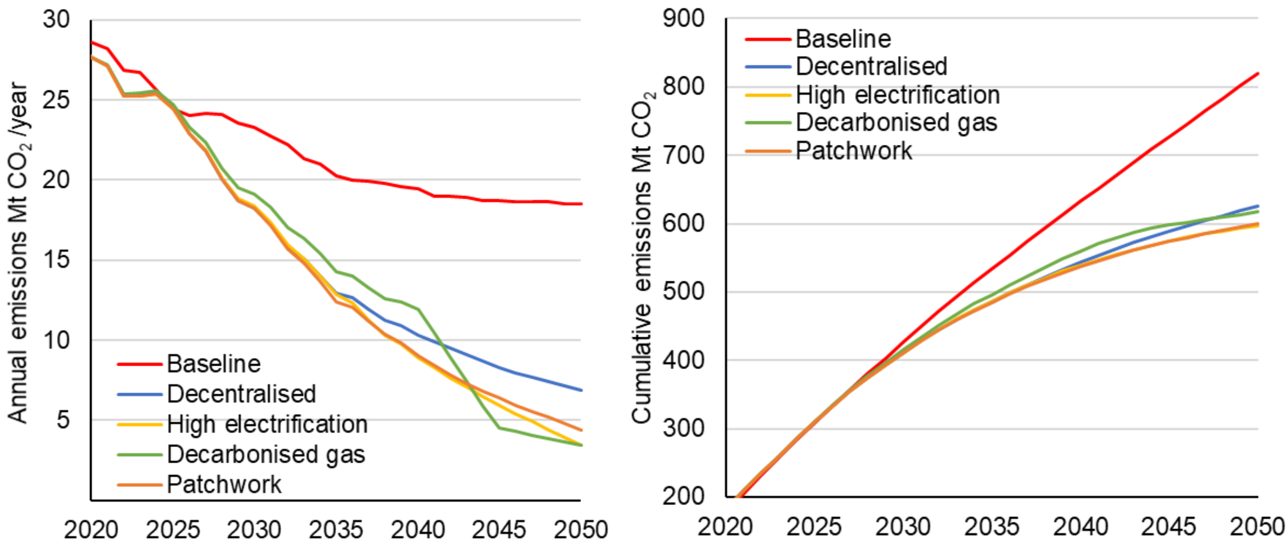


Table 5-1 Summary of CO_2 emissions in the scenarios in 2050

Emissions $MtCO_2$	Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Annual emissions in 2050	18.5	6.9	3.4	3.5	4.4
Cumulative emissions to 2050	820	626	597	617	600

Baseline scenario

Figure 5-4 Baseline scenario annual emissions (left) and energy sources (right) to 2050

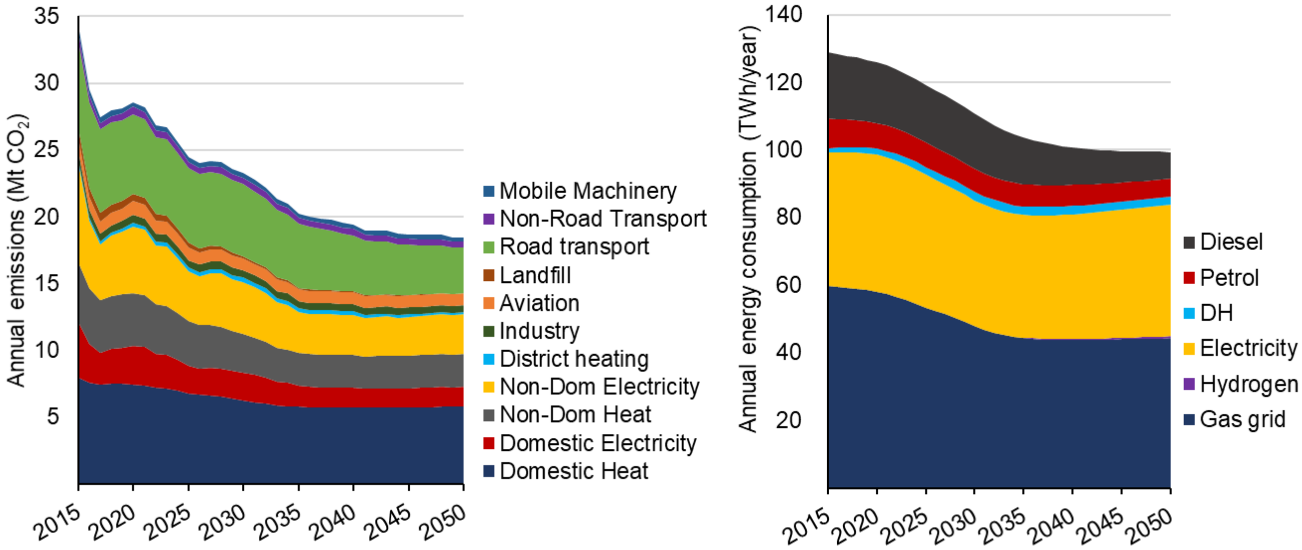
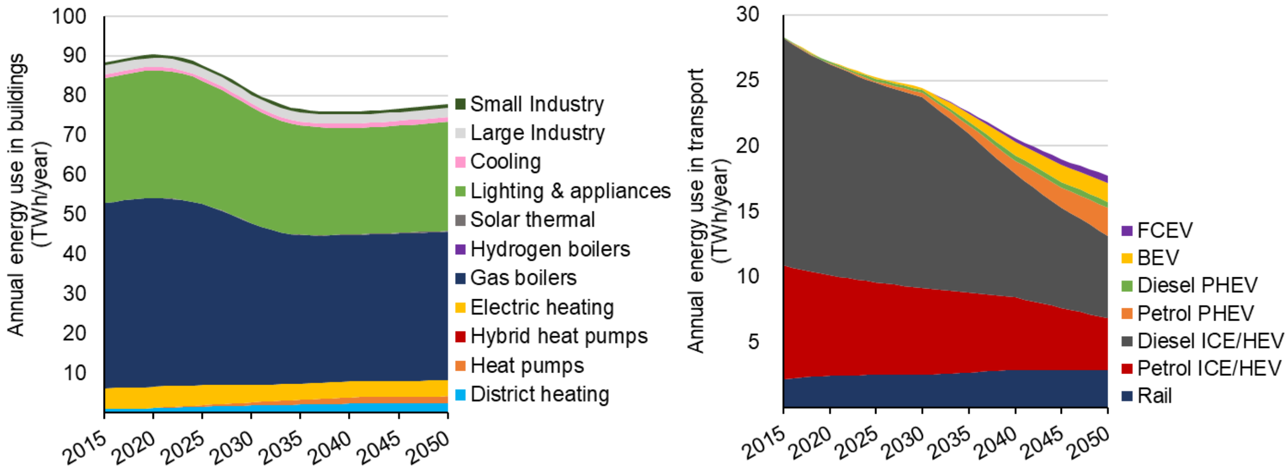


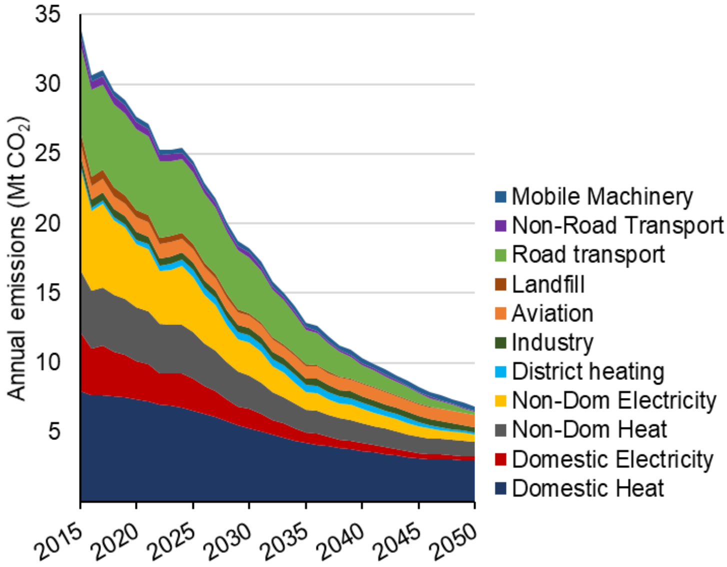
Figure 5-5 Baseline scenario energy use in buildings (left) and transport (right) to 2050



In the Baseline scenario, decarbonisation stagnates around 2035, by which date the energy efficiency measures have been deployed and the decarbonisation of the electricity grid stalls. Annual emissions are 18.5 $MtCO_2$ in 2050, as shown in Figure 5-4 (left). The split of energy sources remains relatively similar to that seen today: primarily natural gas for heating, electricity for lighting and appliances and petrol and diesel for transport, as seen in Figure 5-4 (right). It should be noted that the 'Gas grid' category includes any blending of green gas. The majority of carbon reductions are through electricity grid decarbonisation and energy efficiency measures, as there is low uptake of low-carbon heating and transport technologies, as shown in Figure 5-5.

Decentralised scenario

Figure 5-6 Decentralised scenario annual emissions (left) and energy sources (right) to 2050



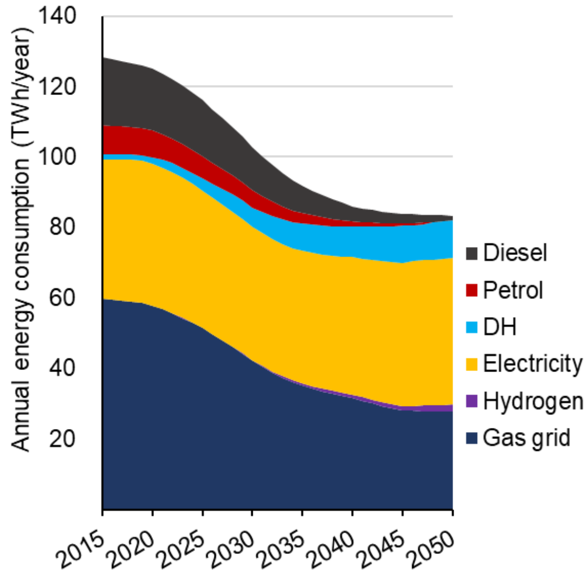
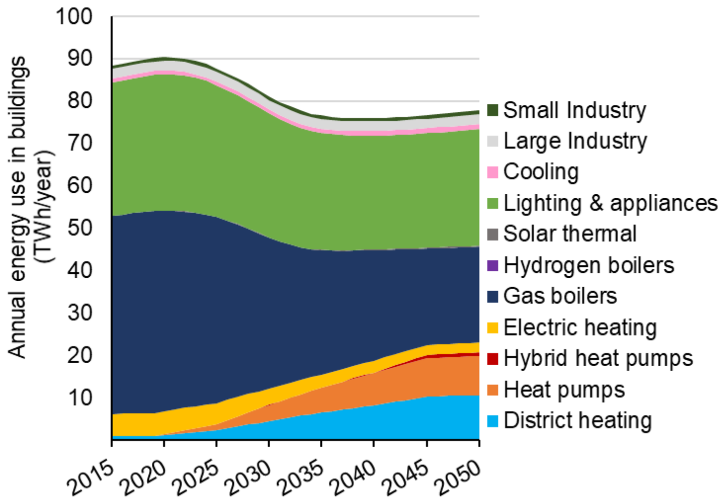
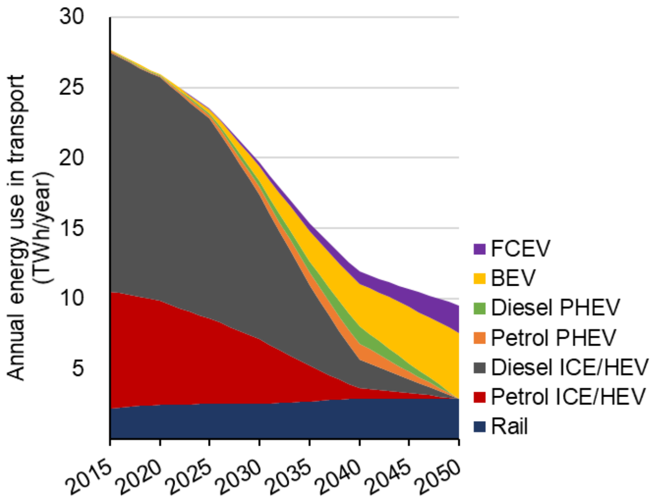


Figure 5-7 Decentralised scenario energy use in buildings (left) and transport (right) to 2050





In the Decentralised scenario, annual emissions drop to 6.9 $MtCO_2$ annually by 2050, with cumulative emissions of 626 $MtCO_2$, as shown in Figure 5-6 (left). Energy supply relies on a large share of electricity (50%), and significant gas (33% including green gas). The share of heat supplied by heat networks is limited to 27% even in the High heat network uptake level, so this scenario is supplemented by significant heat pump uptake (32% of buildings), as shown in Figure 5-7 (left). Even combining heat networks and heat pumps at these levels, with 7 TWh green gas blending, the Decentralised scenario does not reach as deep a level of heat decarbonisation as the other scenarios (aside from the Baseline). Buildings which have not been retrofitted with energy efficiency measures are assumed to remain on gas boilers or direct electric heating. Figure 5-7 (right) shows the transport results to 2050, with all road vehicles reaching zero emissions, and a large share of BEVs.

High electrification scenario

Figure 5-8 High electrification scenario annual emissions (left) and energy sources (right) to 2050

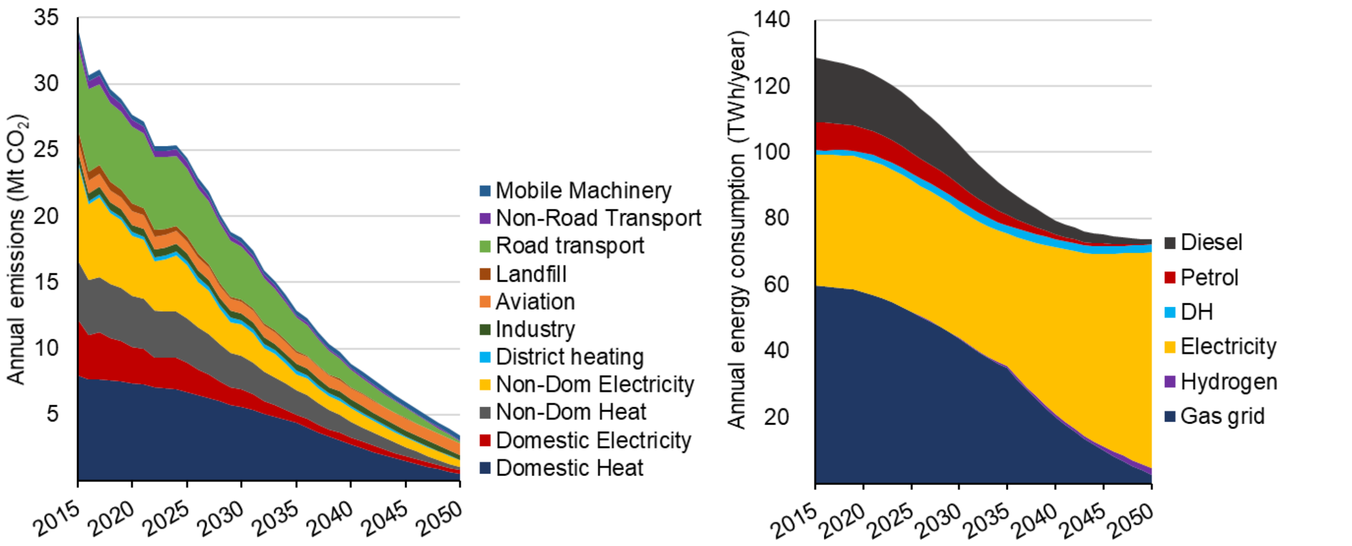
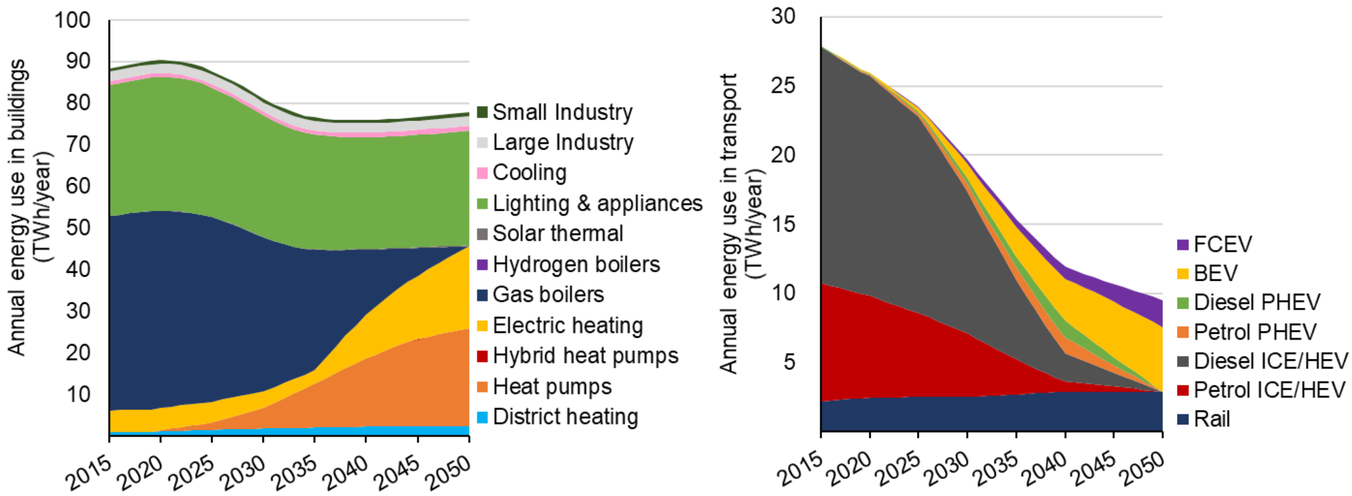


Figure 5-9 High electrification scenario energy use in buildings (left) and transport (right) to 2050



In the High electrification scenario, annual emissions drop to 3.4 $MtCO_2$ annually by 2050, as shown in Figure 5-8 (left), with cumulative emissions of 597 $MtCO_2$. This scenario allows the heat and transport sectors to be almost entirely decarbonised by 2050 due to high uptake of heat pumps and BEVs, as shown in Figure 5-9. By 2050, energy supply relies almost entirely on electricity (92%), under the assumption that the gas grid would no longer be economically viable due to low demand. However, a significant share (19%) of buildings remain unsuitable for heat pumps in 2050, as they do not achieve EPC C, and there is substantial uptake of direct electric heating after 2035 in these buildings. Due to the lower efficiency of direct electric heating than heat pumps, this results in high electricity demand. An advantage of the electrification scenario is that it does not rely on unproven technologies, such as CCS and hydrogen for heating.

Decarbonised gas scenario

Figure 5-10 Decarbonised gas scenario annual emissions (left) and energy sources (right) to 2050

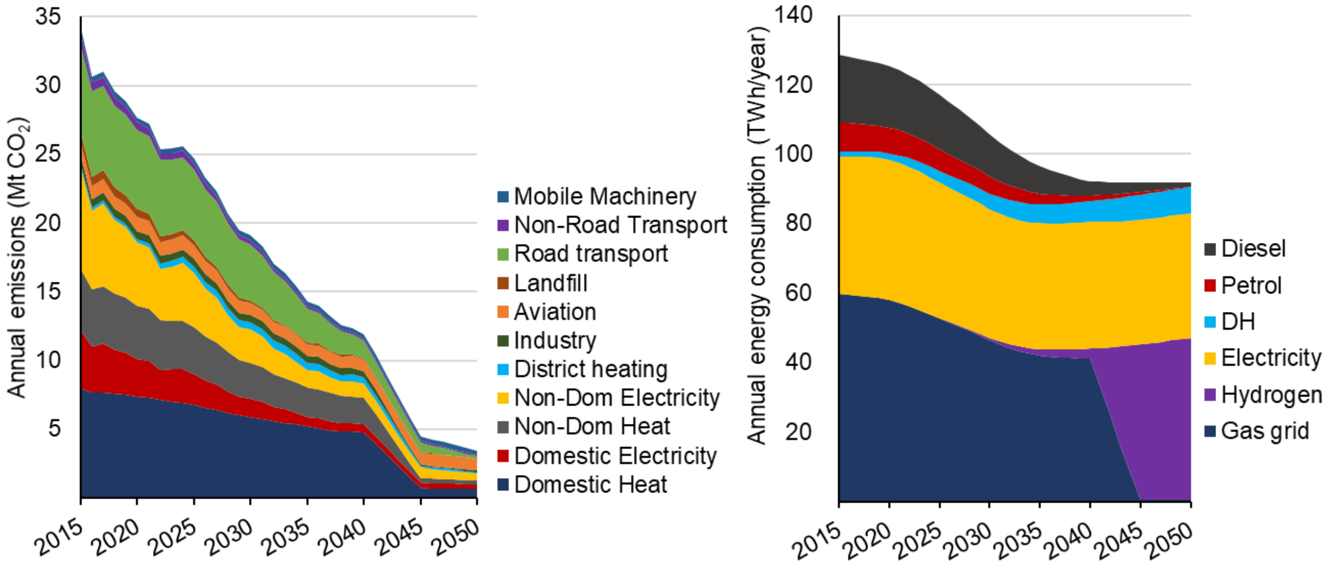
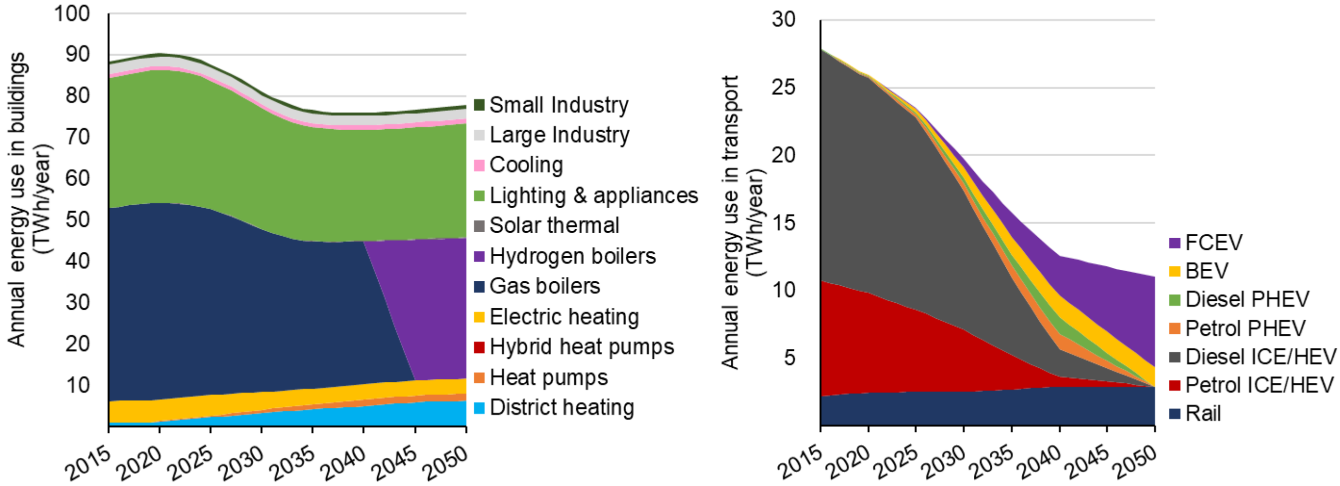


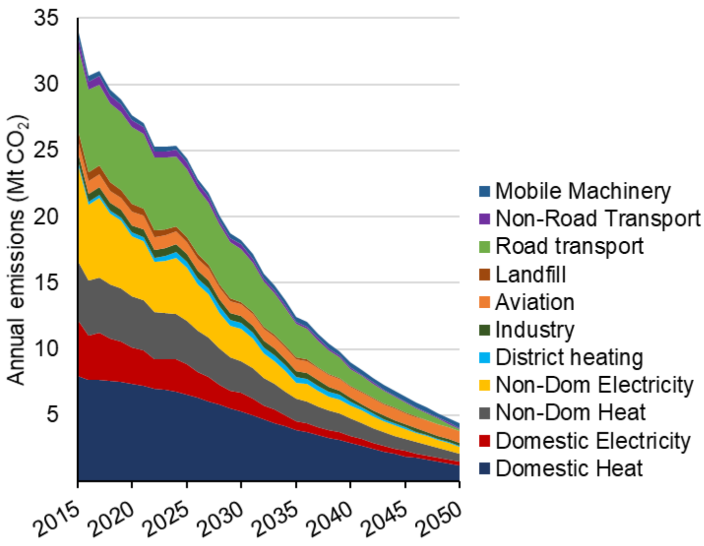
Figure 5-11 Decarbonised gas scenario energy use in buildings (left) and transport (right) to 2050



In the Decarbonised gas scenario, annual emissions fall to 3.5 $MtCO_2$ annually by 2050, with cumulative emissions of 617 $MtCO_2$, as shown in Figure 5-10 (left). The use of a large amount of low carbon hydrogen in the energy mix (over 50% by 2050) as shown in Figure 5-10 (right), allows deep decarbonisation of heat and transport in the later years, primarily through hydrogen boilers and FCEVs. However, even with the inclusion of hydrogen and green gas blending, the carbon emissions remain higher before 2040 than in the other scenarios (aside from the Baseline), leading to higher cumulative emissions than in the High electrification and Patchwork cases. Buildings which have not been retrofitted with energy efficiency measures can also make use of hydrogen boilers for heating. A disadvantage of this scenario is that it relies on the development of commercially viable hydrogen production and CCS by 2040, which is subject to significant uncertainty, as discussed in section 3.4.

Patchwork Scenario

Figure 5-12 Patchwork scenario annual emissions (left) and energy sources (right) to 2050



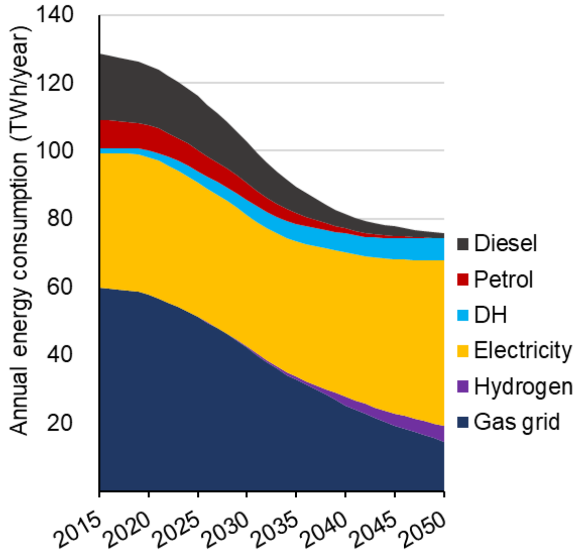
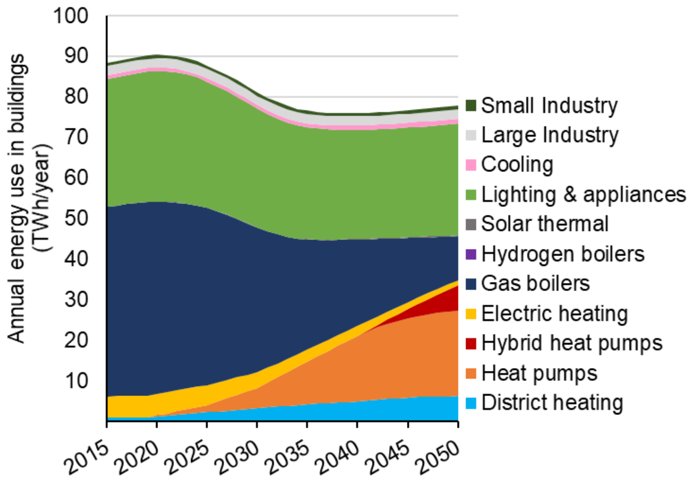
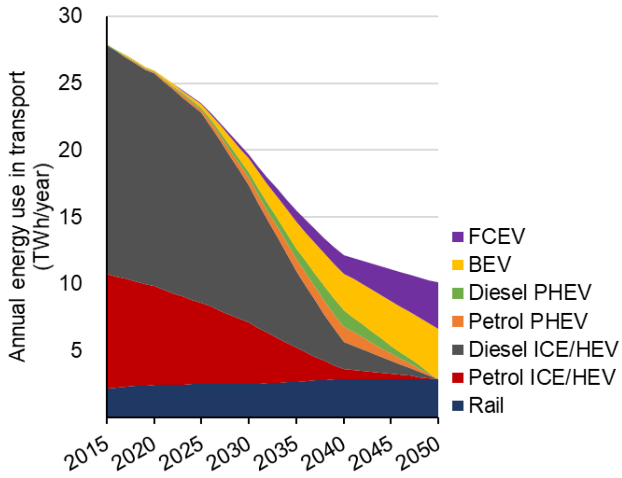


Figure 5-13 Patchwork scenario energy use in buildings (left) and transport (right) to 2050





In the Patchwork scenario, annual emissions drop to 4.4 $MtCO_2$ annually by 2050, with cumulative emissions of 600 $MtCO_2$, as shown in Figure 5-12 (left). The combination of heat networks, high heat pumps, green gas and hydrogen blending, and the hydrogen backbone, allows deep decarbonisation of heat and transport, as well as sufficiently low cumulative emissions. Buildings which have not been retrofitted with energy efficiency measures will either use a HHP, or remain using a gas boiler or direct electric heating. The fuel mix for this scenario in 2050 relies on a large amount of electricity (69%), supported by natural gas (9%), hydrogen (10%) and green gas (10%). A sensitivity on this scenario, without the hydrogen backbone, gives annual emissions in 2050 of 4.7 $MtCO_2$ and cumulative emissions of 604 $MtCO_2$. In this sensitivity, transport comprises lower FCEV uptake, and heat networks and industry are assumed to no longer have any access to hydrogen.

Air Quality

While a detailed analysis of the air quality impacts of these scenarios is beyond the scope of this work, the air quality implications should be considered alongside this evidence base due to the pressing need to reduce emissions of pollutants which are damaging to health. Air pollution caused by carcinogenic diesel emissions, high levels of nitrogen oxides (NO_x) and particulate matter (PM) exacerbate health conditions and shorten the lives of Londoners.[51,52] Currently, transport is one of the biggest emitters of harmful emissions, and the Mayor's Transport Strategy aims to dramatically reduce this through mode switch to walking and public transport, as well as the uptake of BEVs and FCEVs, which lead to zero 'tailpipe' NO_x and PM emissions. This air quality improvement applies to all four decarbonisation scenarios, as they all follow the same trajectory of zero emissions vehicles. Gas combustion in buildings (e.g. from boilers and cookers) is a major source of local pollution, producing 21% of total NO_x emissions across Greater London, and 38% in Central London.[53] In contrast, heat pumps and direct electric heating do not emit harmful emissions locally. The greatest improvement in air quality is therefore likely to be achieved in the High electrification and Patchwork scenarios, in which electric heating is most prevalent. Hydrogen boilers are likely to emit NO_x due to the combustion process; the level of emissions can be reduced, but not eradicated, through technology improvement[54]. Therefore, the Decarbonised gas scenario would be likely to result in higher local NO_x emissions from the heating sector than the other decarbonisation scenarios.

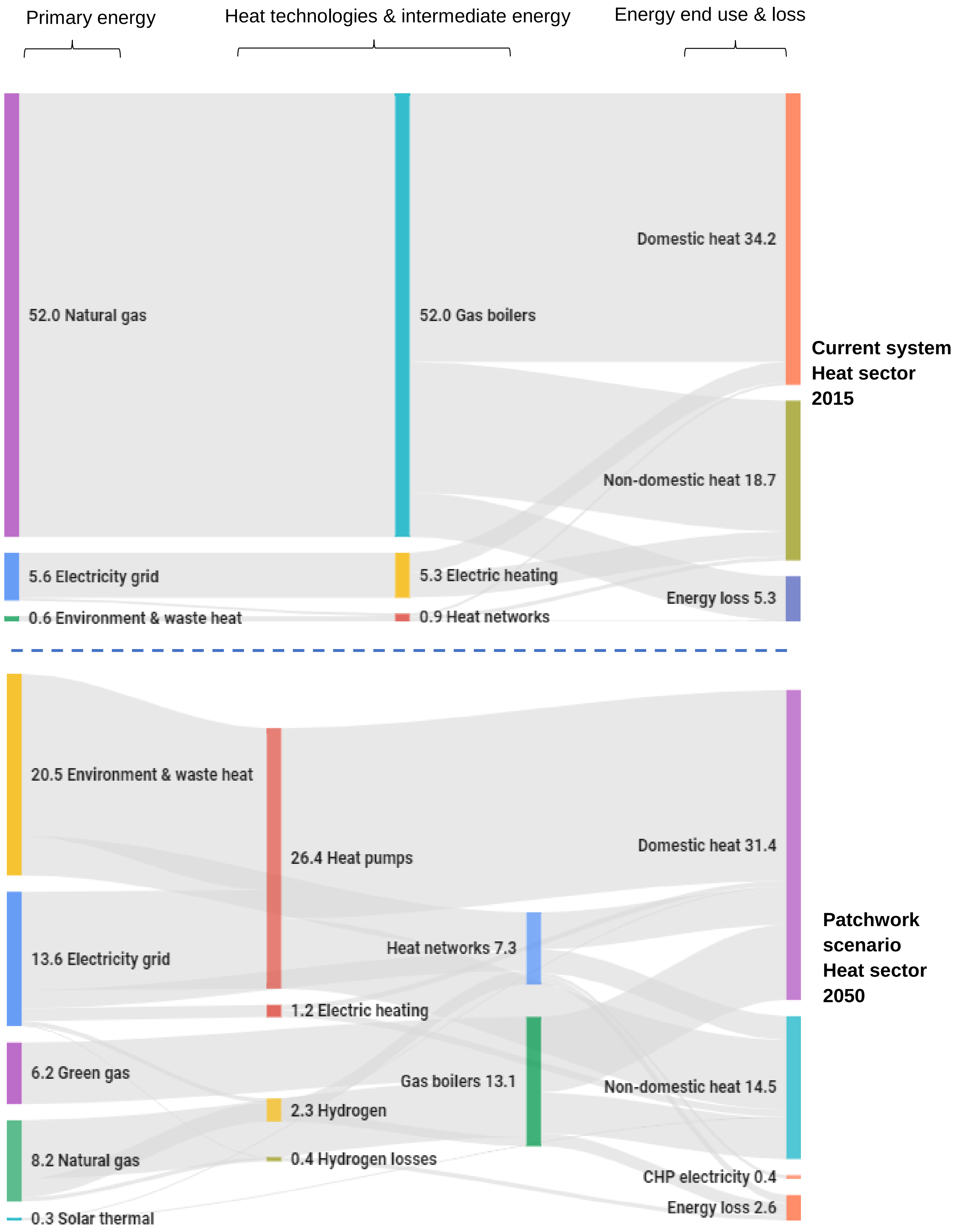
5.2 Energy and Exergy

One of the key sustainability indicators of a scenario is how effectively it uses energy and natural resources. This section compares the various scenarios in terms of two measures relating to the effective use of resources: *energy* efficiency and *exergy* efficiency.

The energy efficiency of a technology provides a measure of how much energy is consumed by the technology to deliver a certain amount of useful energy output. For example, in a gas boiler which is 90% efficient, 90% of the available energy in the natural gas input is delivered as useful heat to the building, and the other 10% is 'lost' as non-useful output. Exergy is a measure of the 'quality' of energy. Exergy analysis allows comparison of how effectively technologies, or scenarios, use natural resources. There is more detail on the concept of exergy in the Appendix section 7.3. In Figure 5-14, Sankey diagrams show the flow of energy, in TWh/yr, from primary energy source to end use for the heat sector. The 2015 energy Sankey shows London's current heating sector, where natural gas provides the majority of heat through gas boilers. The Patchwork scenario 2050 picture is very different, with a wider variety of primary energy sources, including waste heat, heat from the environment and green gas. Primary energy sources, shown on the left, are also used to produce intermediate energy sources, such as hydrogen and heat networks, shown in the centre. It can be seen that the energy losses are significantly reduced in the Patchwork scenario, due to the reduction in use of gas (or hydrogen) boilers and the greater use of heat pumps (either in buildings or supplying heat networks) which are substantially more energy efficient.

[51] *Mayor's Transport Strategy*, 2018, https://www.london.gov.uk/sites/default/files/mayors-transport-strategy-2018.pdf
[52] *London Environment Strategy*, Greater London Authority, May 2018
[53] *Up in the Air, How to Solve London's Air Quality Crisis: Part 2*, Kings College London, Policy Exchange, Capital City Foundation, https://www.trustforlondon.org.uk/documents/86/Up-in-the-Air-Part-22.pdf
[54] *Potential Role of Hydrogen in the UK Energy System*, Energy Research Partnership, 2016

Figure 5-14 Energy Sankey diagrams for the heat sector for 2015 (top) and Patchwork scenario in 2050 (bottom), showing the flow of energy (TWh / yr) from primary energy sources, through intermediates and heating technologies, to end use.



Primary and final energy

Below, in Figure 5-15, is a plot comparing the primary energy use for heating across the scenarios in 2050; this is similar to the left-hand side of the Sankey diagrams. The useful energy required for heating is the same for all five scenarios (including the Baseline) in 2050. In the Decentralised, High electrification and Patchwork scenarios, a significant amount of primary energy comes from the environment due to the high use of heat pumps, both building scale and in heat networks, reducing the resource consumption. However, in the Decarbonised gas scenario, there is a larger primary energy consumption (mainly natural gas) due to energy losses in both the hydrogen production process and in the combustion of hydrogen in boilers.

Figure 5-15 Comparison of primary energy use for heating across the scenarios in 2050

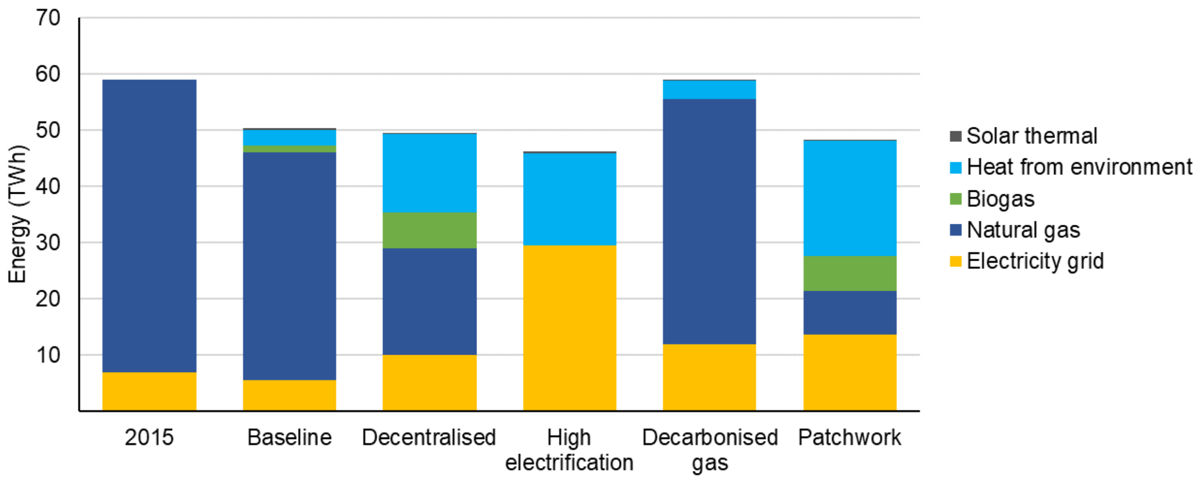
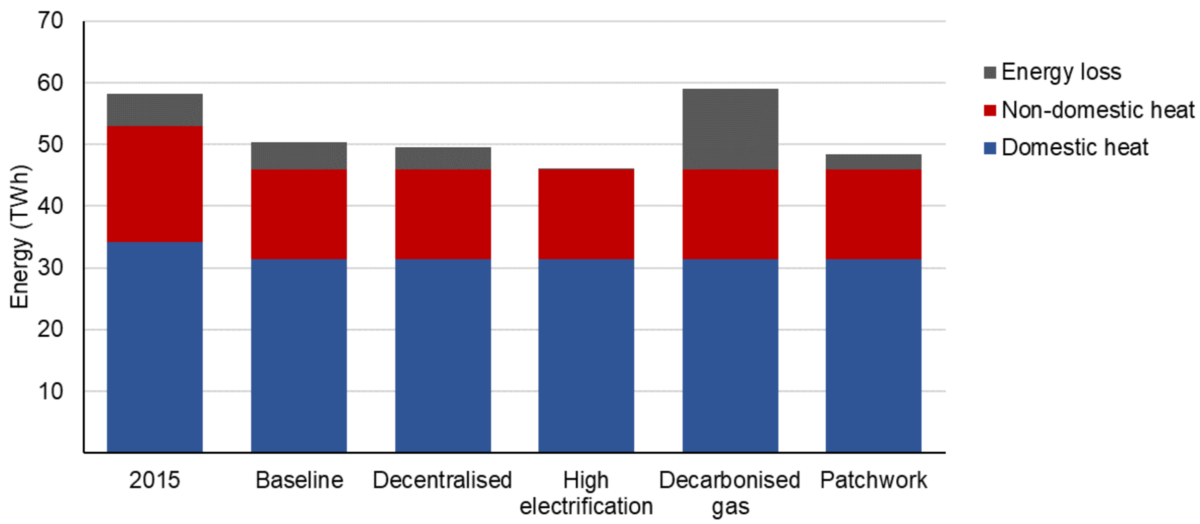


Figure 5-16 shows the energy use and loss for the heating sector, similar to the right-hand side of the Sankey diagrams. The energy losses are smallest in the High electrification scenario, due to almost entirely electric forms of heating in 2050. However, the uptake of direct electric heating results in higher electricity consumption than if they could be replaced by heat pumps. In the Decarbonised gas scenario, there is a larger energy loss, as noted above, due to losses in both hydrogen production and combustion.

Figure 5-16 Comparison of energy use and losses for heating (and mCHP electricity) across the scenarios in 2050

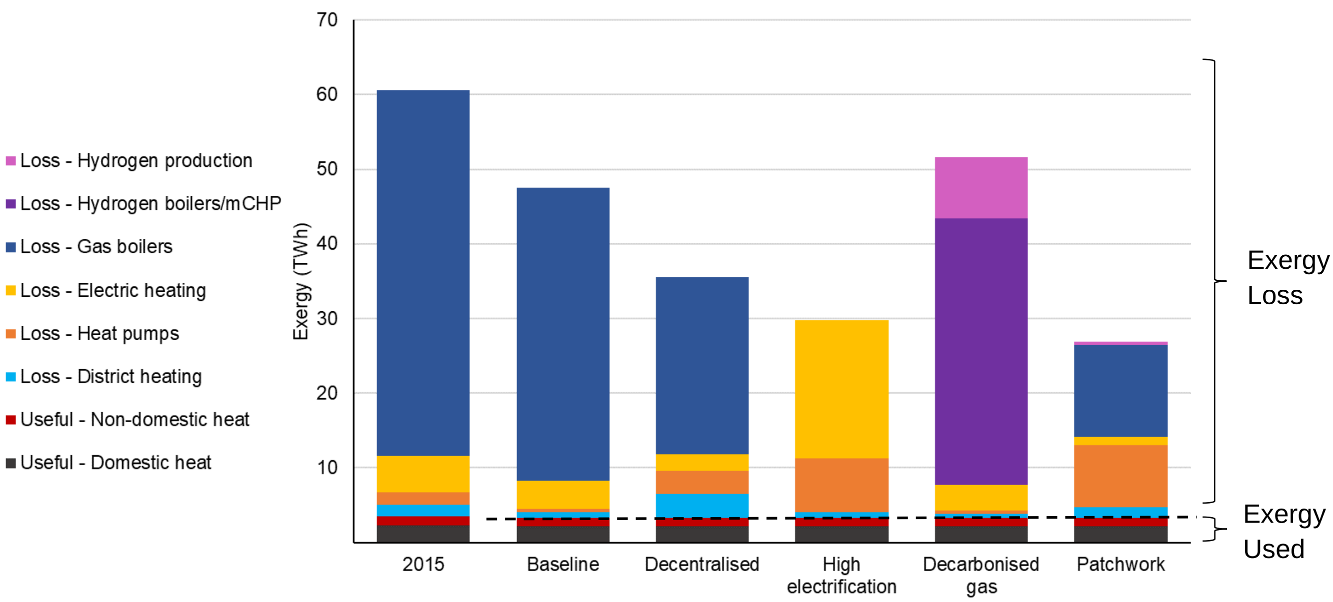


Exergy

Figure 5-17 shows the exergy analysis of the heat sector in the five scenarios in 2050 relative to 2015. The useful exergy delivered for heat is again the same across all scenarios (including the Baseline) in 2050. The useful exergy is represented as the bottom two segments of each stacked bar, below the dotted line, for Domestic and Non-domestic heat. All segments above the dotted line show exergy loss, and refer to exergy loss associated with the different heating technologies.

The total exergy destruction is lowest in the Patchwork scenario due to high use of low grade heat (waste heat and heat from the environment) in buildings scale heat pumps and through heat networks. The Decarbonised gas scenario results in the highest exergy destruction, mainly due to the combustion of hydrogen in boilers and lower utilisation heat from the environment. This can be interpreted as a less sustainable solution as it consumes more natural resources.

Figure 5-17 Exergy delivered and destroyed for heating technologies in each scenario in 2050



A summary of how effectively each scenario uses energy and exergy is given in Table 5-2. Where the heat energy output relative to primary fuel input is greater than 100%, this indicates significant energy used from the environment and waste heat sources (for the same reason a heat pump has an efficiency greater than 100%). The most efficient use of fuels occurs in the Patchwork scenario, due to high use of environmental and waste heat sources. The exergy effectiveness is lowest in the Decarbonised gas scenario.

Table 5-2 Summary of energy and exergy efficiency in the heat sector in 2050, relative to 2015

Scenario	Heat energy output relative to primary fuel input	Exergy efficiency
2015	90%	6%
Baseline	97%	7%
Decentralised	130%	9%
High Electrification	155%	11%
Decarbonised gas	83%	6%
Patchwork	166%	12%

This energy and exergy analysis provides a method to understand aspects of the scenario sustainability, particularly natural resource consumption. A more effective energy system will utilise waste heat and low quality energy sources for low quality applications, such as space heating. However, there is often a trade-off to be made with investment, as the most efficient technologies, such as heat pumps, are often the most capital intensive.

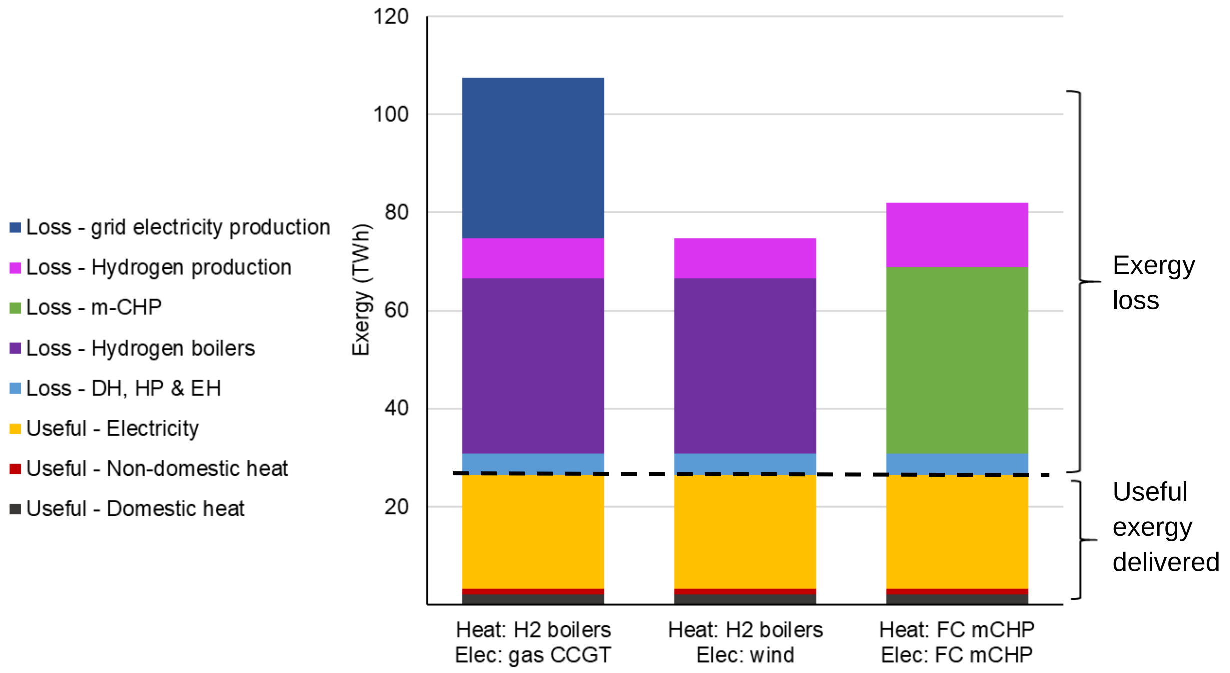
Decarbonised gas exergy sensitivity

A sensitivity on the Decarbonised gas scenario has been completed to understand the impact of using hydrogen fuel cell micro CHP (FC mCHP) in buildings, rather than hydrogen boilers. This is because FC mCHP has the potential to increase the efficiency of the energy system by utilising heat that would otherwise be wasted, and also to reduce harmful local emissions of NO_x. To allow a fair comparison, the electricity produced using mCHP must be included in the analysis and compensated by an equal quantity of electricity from the grid where hydrogen boilers are used for heating; we have considered two production methods for the grid electricity, gas turbine (CCGT) and wind turbines. As shown in Table 5-3 and Figure 5-18, FC mCHP provides greater exergy efficiency than using hydrogen boilers for heating with gas CCGT separately for electricity production. However, if in 2050 the majority of the electricity in the grid is produced through renewables such as wind turbines, the use of mCHP no longer increases the exergy sustainability of the scenario.

Table 5-3 Exergy efficiency of Decarbonised gas scenario sensitivities in 2050

Sensitivity	Exergy Efficiency (%)
Heat: H_2 boilers + Electricity: gas CCGT	25%
Heat: H_2 boilers + Electricity: wind	35%
Heat: FC mCHP + Electricity: FC mCHP	32%

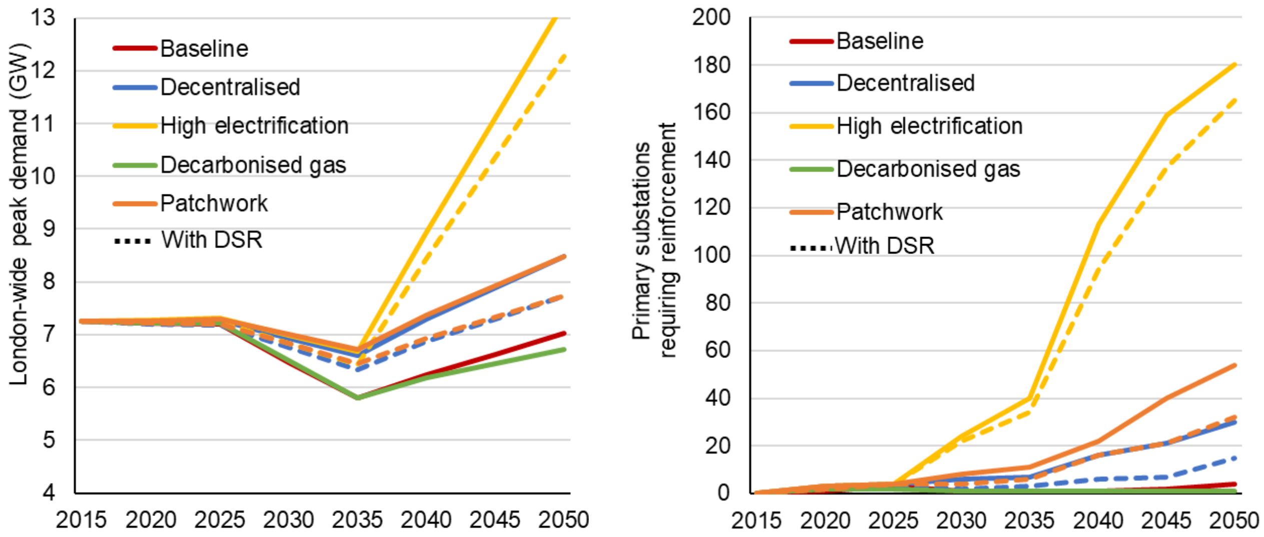
Figure 5-18 Exergy use and loss in Decarbonised gas sensitivities for the heat sector (with a proportion of electricity) in 2050



5.3 Electricity network and the impact of DSR and storage

The plot on the left of Figure 5-19 shows the trajectory of the London-wide peak demand predicted for the five scenarios, while the number of primary substations requiring reinforcement are shown on the right. Electricity demands for buildings have been modelled in 2015, 2025, 2035, and 2050 and interpolated across the intermediate years; this interpolation is visible in Figure 5-19 (left). The effect of DSR is shown in the dashed line for the three scenarios in which the peak demand rises above the 2015 level (Decentralised, High electrification, and Patchwork). All scenarios see a reduction in peak demand from 2015 to 2035 due to the high uptake of energy efficiency including insulation of buildings and the installation of more efficient lighting and appliances (see section 3.1). The reduction in electricity demand due to energy efficiency is sufficient in all scenarios to offset, at a London-wide level, the increase in electricity demand due to electrification of heat and transport to 2035. It should be noted that the current analysis has assumed that peak loads occur in January, although a significant minority of substations, predominately in central London, experience summer peaks. Further details of the assumptions behind this result and associated caveats are discussed below.

Figure 5-19 London-wide peak electricity demand (left) and the number of primary substations requiring reinforcement (right)

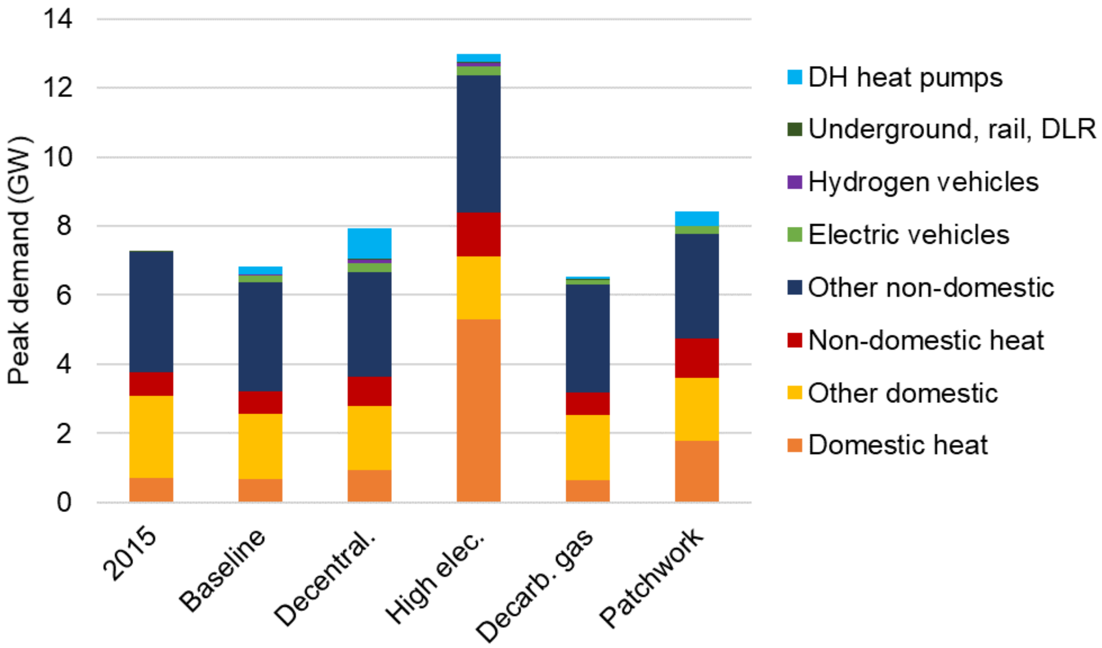


Peak demand rises again in all scenarios after 2035, with the High electrification scenario experiencing the most significant increase in demand. In this scenario, we estimate that between 160 and 180 of London's 235 primaries will need reinforcing by 2050. The peak increase in this case is largely due to the significant uptake of direct electric heating in buildings where heat pumps are not deployed. Although heat pumps provide 20% more heat than direct electric heating in 2050, they are installed in energy efficient buildings and make use of thermal storage for hot water even when additional thermal storage for heating is not present. Therefore, they operate more evenly throughout the day and do not have the sharp peaks seen in the typical use of direct electric heating. In the High electrification scenario, heat pumps contribute about 1.5 GW to the 2050 peak, while direct electric heating contributes 3.8 GW.

While the Decentralised and Patchwork scenarios see very similar increases in the London-wide peak demand, the number of primary substations requiring reinforcement is lower in the Decentralised scenario due to the concentration of much of the additional demand at a smaller number of large DH energy centres rather than being spread across a larger number of individual homes and businesses. While the Baseline and Decarbonised gas scenarios maintain a London-wide peak demand below the 2015 value and hence required reinforcement is kept to a minimum, a small number of primaries still require reinforcement in those scenarios due to localised increases in demand.

Figure 5-20 presents the composition of the peak demand on all primary substations in 2015 and in each scenario in 2050. The impact of DSR is included in the Decentralised, High electrification, and Patchwork cases (due to the benefit shown above). The peak power demand presented here is different from that on the left of Figure 5-19; it is the sum of the individual primary substation peaks which occur at different times of the day. The increase in demand for domestic and non-domestic heating drives the noticeable increase in the High electrification scenario.

Figure 5-20 Contribution of individual sectors toward the peak demand on all primary substations

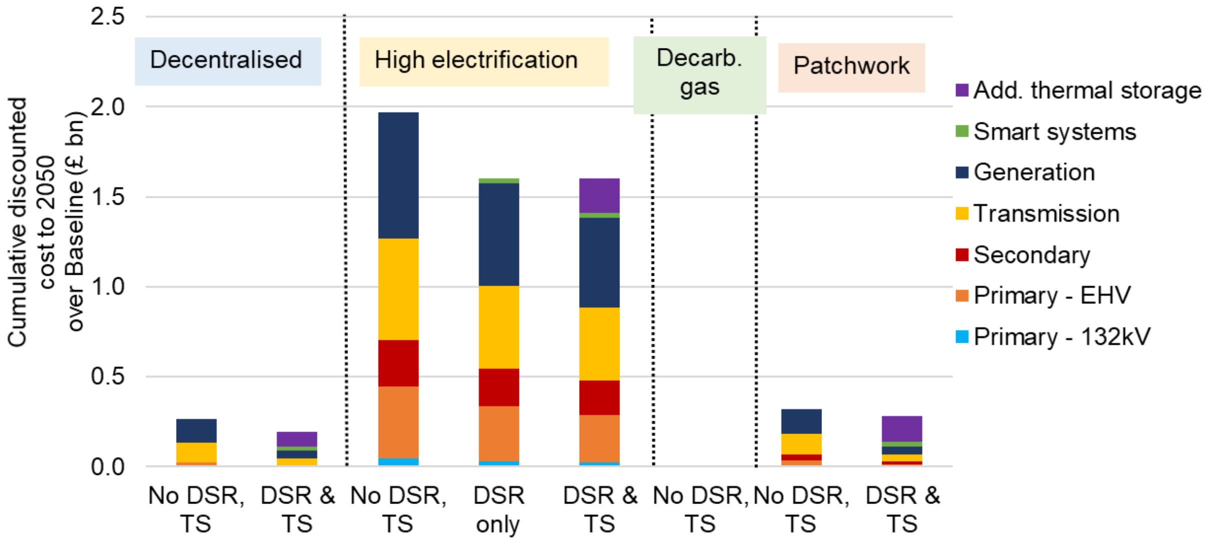


Value of DSR and thermal storage

Figure 5-21 shows the cumulative cost of electricity system reinforcement, and of the building level systems that enable demand side response (DSR) to reduce the requirement for grid reinforcement, in the four scenarios relative to the Baseline scenario. The Decentralised and Patchwork scenarios are shown with and without DSR. The DSR results include the presence of additional thermal storage (TS) in 10% of households using heat pumps and direct electric heating. The additional thermal storage takes the form of a 300 litre hot water tank per household which stores heat for both space heating and hot water. This is three times larger than 'standard' thermal storage assumed to be present in all electrically-heated households, which is a 100 litre tank used for hot water only. Many homes or flats in London do not have sufficient space for this additional thermal storage to be installed, so higher uptake than 10% is considered unlikely without considerable incentives. The presence of the larger thermal store allows consumers to increase their response to DSR events, as shown in Table 4-3 above.

Three cases are shown for the High electrification scenario: without additional thermal storage and DSR, including DSR but no additional thermal storage, and finally with both additional thermal storage and DSR. Only the case without DSR is shown for the Decarbonised gas scenario, where DSR is not needed and so is not cost-effective.

Figure 5-21 Cumulative cost of electricity system reinforcement and the building level systems enabling DSR



Without additional thermal storage, consumers are only able to reduce their heat demand for approximately 30 minutes before the building temperature begins to drop, allowing a diversified peak reduction of less than 20%[55]. With a charged additional thermal storage tank the building heating system can be switched off for several hours, making a more significant contribution to reducing the peak demand during the 2 to 3 hour morning and evening peak periods.

Although the smart building systems and additional thermal storage must be purchased to enable the benefits of DSR, these costs are, in most scenarios, outweighed by the reduction in system reinforcement costs. This is most significant for the High electrification case, where the additional cost over the baseline is reduced from £2.0 bn to £1.6 bn when DSR is used without additional thermal storage. The system cost is further reduced to £1.4 bn when DSR is combined with additional thermal storage, but the storage itself adds a further £0.2 bn. Although this analysis indicates that the financial benefit from additional thermal storage is marginal, storage systems could provide other services not considered here, potentially including services to the grid or to energy suppliers to reduce energy costs and ensuring security of heat supply to the consumer. The cost to the network operator of facilitating and managing DSR has not been included in this analysis.

Thermal storage is also assumed to be present in all heat networks. This serves to reduce the peak electricity demand from the heat network energy centres and reduce the capital cost of the heat network energy plant[56]. In the Decentralised and High electrification scenarios district heat networks are supplied using heat pumps in 2050. Without thermal storage, these must be sized to cover the winter peak demand on the network although this level of heat output is not needed for most of the year. Thermal storage allows a smaller system to be purchased which can be operated more efficiently while still serving the needs of the connected consumers.

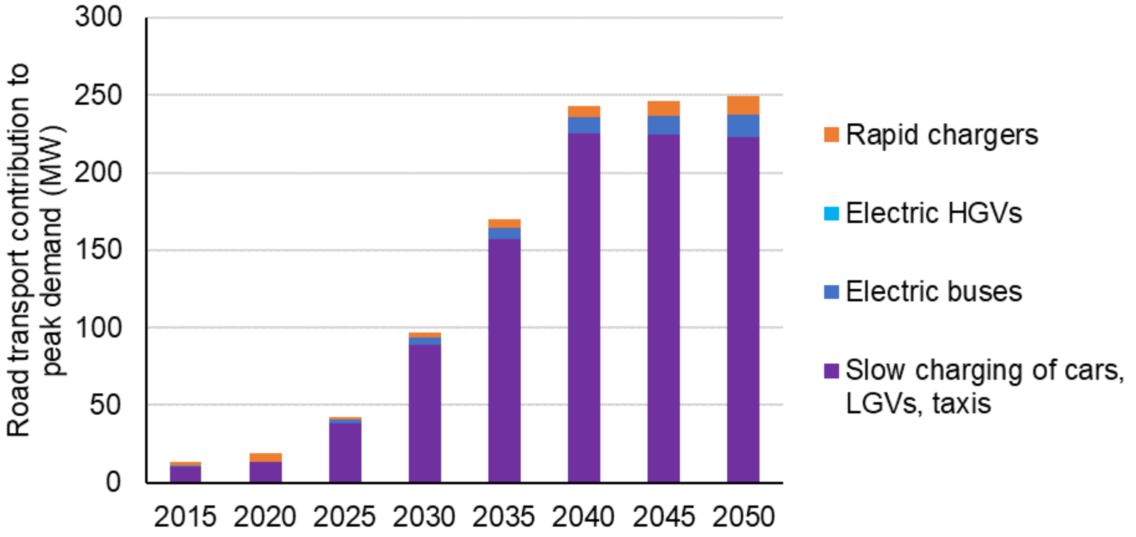
The amount of battery storage likely to be available in future years to provide such services at a cost lower than other reinforcement options is highly uncertain and has therefore not been included quantitatively in this study.

[55] The length of time a heating system can be switched off without additional thermal storage will depend on the energy efficiency of the dwelling, outside temperature, and the level of comfort acceptable to the user.
[56] Thermal storage in the context of heat networks has been included in the total cost of district heating. See section 7.2 and the charts workbook for further details.

Impact of electric vehicles

The sum of the power demand from electric vehicles at the peak time of the individual substations is shown in Figure 5-22 for the High electrification scenario. The effects of DSR are included, and have reduced the London-wide peak demand by about 4 MW in 2025. In all years, the peak demand from EV is dominated by the slow charging of cars, LGVs, and taxis due to their large numbers relative to buses and HGVs, and the affordability of slow charging relative to rapid charging. There is a reduction in impact from rapid charging from 2020 to 2025 due to the increase in the number of rapid chargers expected during this period, which will spread the power demand across more electricity substations reducing the impact of individual (or clusters of) rapid chargers at the peak time of each substation.

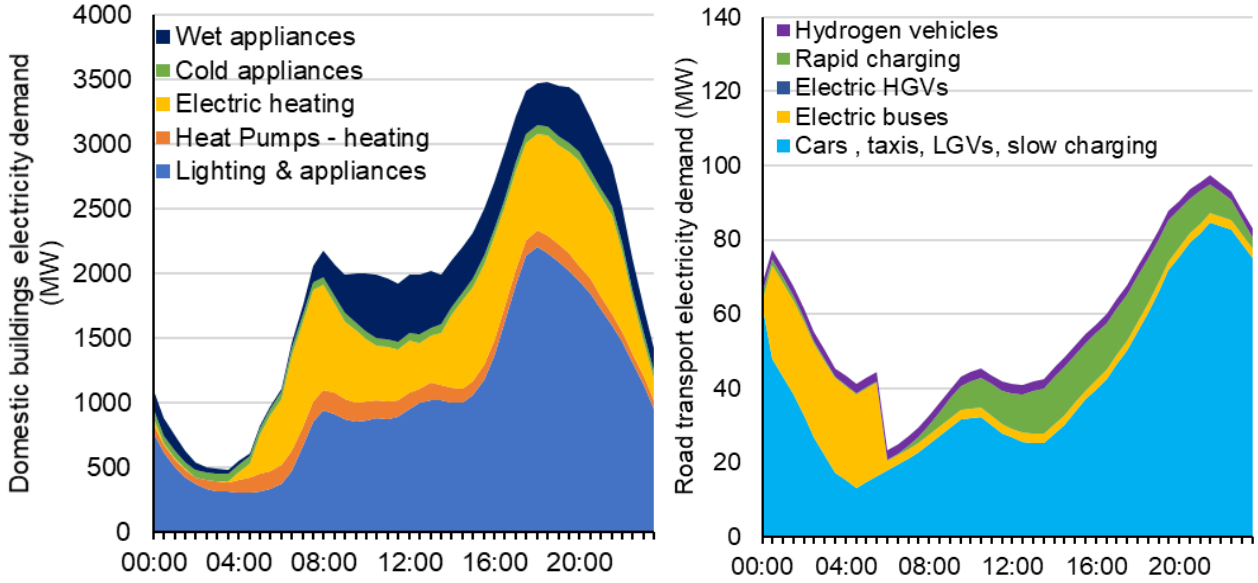
Figure 5-22 Contribution of electric vehicles to the peak demand on all primary substations in the High electrification scenario



London-wide hourly profiles of the power demand for buildings (left) and for transport (right) in the High electrification scenario in 2025 in January are shown in Figure 5-23. These do not include DSR, which would reduce the domestic buildings demand at the peak time by 27 MW and the transport demand at peak time by 4 MW in 2025, as DSR uptake is assumed to remain relatively low in 2025. While the peak demand from EVs alone is nearly 100 MW and occurs at about 9 pm[57], the demand at the London-wide time of peak demand is 70 MW. The London-wide peak winter demand of 7.2 GW occurs between 5:30 and 7:30 pm in 2025 and is driven by domestic and non-domestic lighting, appliances, and heating. In summer, the London-wide peak demand of 4.8 GW occurs around 5:30 pm when EV demand is about 55 MW. This effect of differing peak times also occurs at the individual substation level and contributes to the low impact of EVs seen above in Figure 5-20. The observed impact is further reduce by the flexibility of EV demand; hydrogen electrolysis and some of the EV demand can be shifted out of the peak time without compromising quality of service. As discussed further below, local variations in the demand from EVs may not be accurately captured by the model and may exacerbate grid constraints more severely than shown here.

[57] The demand profile for slow charging of vehicles is based on data from several vehicle trials: My Electric Avenue (2013-2015, http://myelectricavenue.info/), Plugged in Places (2010-2013, https://www.gov.uk/government/publications/lessons-learnt-from-the-plugged-in-places-projects), and Low Carbon London (2010-2014, http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/)

Figure 5-23 London-wide hourly profiles of power demand in January for domestic buildings (left) and transport (right) in 2025



Limitations to the Power modelling

The results presented indicate the levels of system reinforcement required given the uptake of the technologies prescribed in each scenario but are subject to a number of limitations and caveats relating to the assumptions made and the modelling approach employed. All scenarios include extensive improvements in energy efficiency in buildings, lighting and electrical appliances, using the efficiency deployment scenarios developed in a related study by Arup for the GLA (section 3.1). It should therefore be noted that the Baseline scenario is not a "business as usual" scenario but includes ambitious levels of energy efficiency. The resulting reductions in lighting, appliance, and heating loads offset the increase in electricity demand from electric vehicles and electrification of heat in all scenarios to 2035. An estimate of the reinforcement needed in the High electrification scenario without these reductions due to energy efficiency was obtained by adding the increased demands from transport and heat pumps up to 2030 to the 2015 peak demand. The sum of the peak demands on London's primary substations rises by 600 MW to reach 7.9 GW in 2030, compared with a reduction of 250 MW when high energy efficiency uptake is assumed. Heat pumps account for 500 MW of the 600 MW increase, while home and workplace charging of electric vehicles contribute 90 MW. Rapid chargers and electric buses account for the remaining 10 MW. This increase in peak electricity demand would increase the expected spend on grid reinforcement to 2030, estimated at £1.5 billion[58], by £350 million, an increase of around 20%.

Although the technologies have been deployed spatially across the London LSOAs based on their anticipated distribution, the power modelling does not capture all relevant spatial variations. While the uptake of heat pumps and other technologies at the LSOA level is affected by the spatial variations in housing tenure types, other spatial variations in uptake (for example, if technology uptake is affected by socio-economic factors) may cause further grid constraints that are not reflected in the current modelling. Detailed modelling at the secondary substation level would be needed to capture these effects and more accurately assess the level of needed reinforcement.

The model assumes that peak loads are principally driven by domestic heating and lighting and therefore occur in January. A significant minority of substations, predominately in central London, are dominated instead by

[58] UKPN RIIO-ED1 Business plan 2015-2023 (https://www.ukpowernetworks.co.uk/internet/en/about-us/business-plan/), uplifted for inflation to 2016-2017 price levels

commercial buildings whose need for reinforcement is determined by summer air conditioning use. Substation peak capacity reduces with increases in temperature; a summer load may breach a substation's summer firm capacity despite being lower in kW terms than the peak load that can be accommodated in winter. The caveats around energy efficiency uptake mentioned above would apply equally to summer peak loads.

The costs shown have been calculated using published £/MW figures[59,60] although individual substations will need varying levels of reinforcement of cables, transformers and switchgears. Some economies of scale are likely to occur when many substations are reinforced in a single campaign, particularly when the need for future reinforcement is known in advance. The costs shown do not include circuit upgrade costs as assessment of the requirement for circuit upgrades is beyond the scope of the power model and the available data on existing circuit capacity. Additional investments required to maintain power quality are also excluded from the current modelling.

Alternative approaches to electricity network reinforcement

There are several alternative approaches to electricity network reinforcement and regulation that should be considered to support London's decarbonisation, particularly if the High electrification scenario is preferred. The challenge of a rapid increase in electricity demand, requiring substantial electricity network upgrades, could be mitigated through flexible regulation to allow more advanced planning.

Distribution network operators are likely to deploy dynamic and smart solutions at the infrastructure level, in addition to DSR and storage at the building level. These smart infrastructure solutions may be deployed before or in tandem with traditional network reinforcement if they can be shown to reduce the overall infrastructure costs. A transmission-based approach to reducing constraints on the distribution network could also provide a means of meeting load growth at reduced cost. This could involve bringing new transmission infrastructure into constrained areas to connect certain loads directly, relieving peak loads on the distribution network. One option that could be explored is installation of medium-voltage direct current (MVDC) lines, particularly for connection of loads that require DC supply, such as rapid EV charging stations. There is also likely to be a market for battery electricity storage at the transmission level which may provide a range of grid services including the reduction of distribution network constraints.

[59] UKPN RIIO-ED1 Business plan 2015-2023 (https://www.ukpowernetworks.co.uk/internet/en/about-us/business-plan/), uplifted for inflation to 2016-2017 price levels
[60] *2050 Energy Scenarios – the UK gas networks role in a 2050 whole energy system*, KPMG (2016).

5.4 Investment

Investment results example cashflow analysis

The investment required for each scenario over time was calculated by combining the building level, infrastructure and fuel costs. An example of the cashflow results can be seen in Figure 5-24 and Figure 5-25 for the Decarbonised gas scenario. For the equivalent graphs for all scenarios, please see the charts workbook[15] associated with this report.

Figure 5-24 Investment cashflow example for the Decarbonised gas scenario to 2050, with overall cost (left) and fuel cost (right)

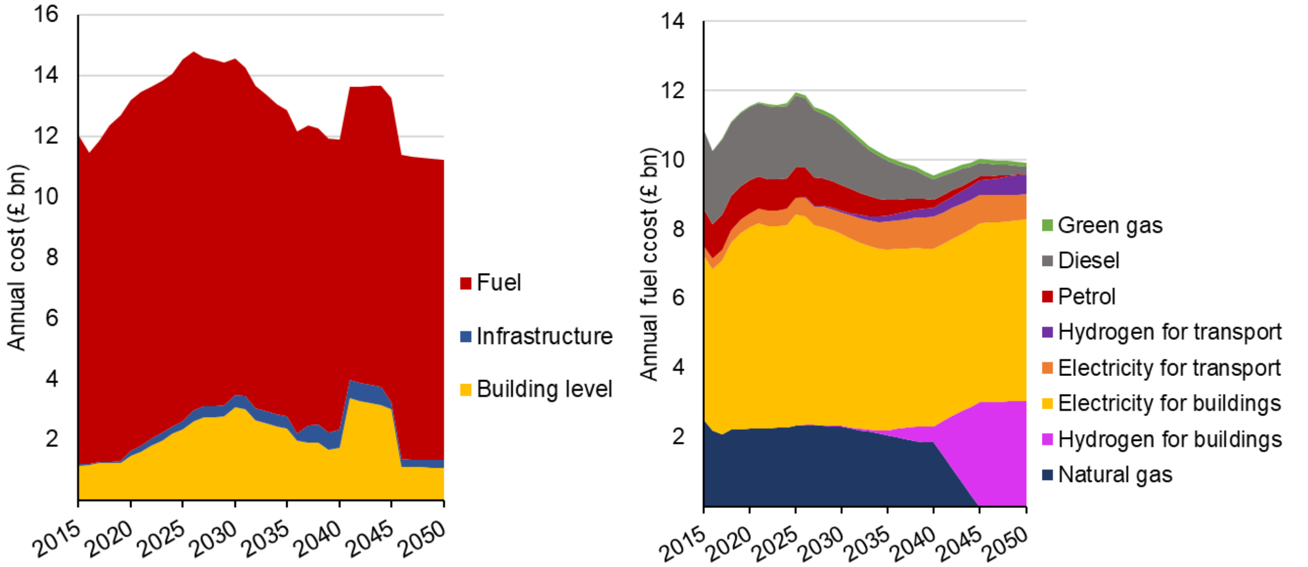
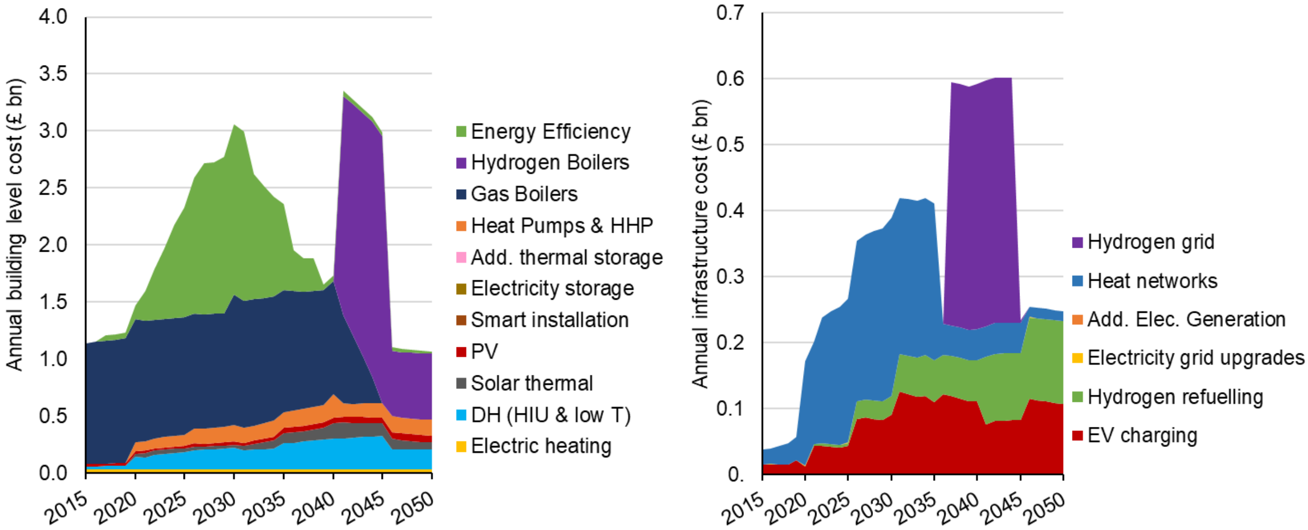


Figure 5-25 Investment cashflow example for the Decarbonised gas scenario to 2050, with building level cost (left) and infrastructure cost (right)



Comparing scenario investment

There are significant uncertainties associated with the cost of each scenario, and an estimate of the range of uncertainty in the costs is presented in the next section. The cumulative discounted scenario costs to 2050 under the central cost assumptions are presented first, in Table 5-4.

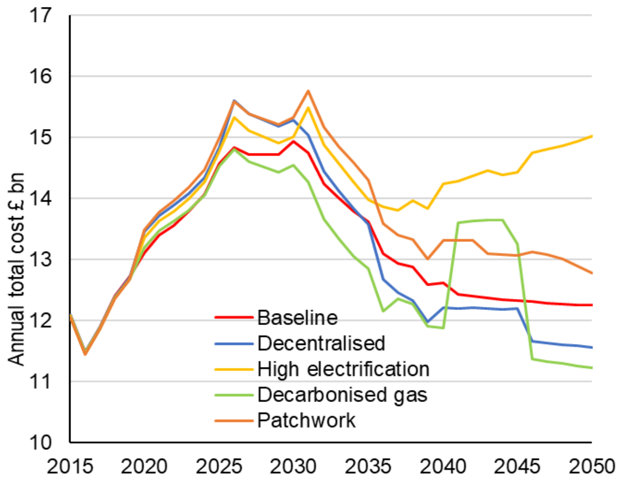
In all scenarios, the fuel costs are the largest proportion of the overall cost. Fuel costs are higher in the Baseline scenario than the other four scenarios due to the high cost of petrol and diesel (including taxes), coupled with the lower efficiency of ICE vehicles; this raises the cost of the Baseline scenario to above the Decentralised and Decarbonised gas scenarios.

Table 5-4 Summary of cumulative discounted scenario costs, under the central assumption, to 2050, with associated emissions results

Scenario Summary		Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Annual emissions in 2050 $MtCO_2$		18.5	6.9	3.4	3.5	4.4
Cumulative emissions to 2050 $MtCO_2$		820	626	597	617	600
Total Cost £ bn		£278	£279	£292	£274	£288
Total Cost w/o fuel £ bn		£40	£55	£61	£48	£61
Building level £ bn	**Total**	**£39**	**£49**	**£57**	**£42**	**£56**
	Energy Efficiency	£10	£10	£10	£10	£10
	DH (HIU & low T)	£1	£5	£1	£3	£3
	Heat Pumps & HHP	£2	£12	£24	£2	£24
	Solar thermal	£1	£1	£1	£1	£1
	Hydrogen Boilers	£0	£0	£0	£5	£0
	Gas Boilers	£23	£18	£16	£19	£16
	Electric heating	£0.8	£0.6	£1.4	£0.7	£0.5
	PV	£0.3	£1.9	£1.9	£0.7	£0.7
	Smart installation	£0.00	£0.02	£0.03	£0.00	£0.03
	Add. thermal storage	£0.0	£0.1	£0.2	£0.0	£0.1
Infrastructure £ bn	**Total**	**£1.8**	**£6.5**	**£4.4**	**£5.8**	**£5.1**
	Elec. grid upgrades	£0.0	£0.0	£0.9	£0.0	£0.1
	Elec. Network storage	£0.0	£0.0	£0.5	£0.0	£0.0
	Heat networks	£0.7	£4.1	£0.7	£2.7	£2.7
	Hydrogen grid	£0.0	£0.0	£0.0	£1.2	£0.1
	EV charging	£1.0	£2.2	£2.2	£1.4	£2.0
	Hydrogen refuelling	£0.1	£0.1	£0.1	£0.4	£0.2
Fuel £ bn	**Total**	**£238**	**£224**	**£231**	**£227**	**£226**
	Natural gas	£46	£40	£37	£40	£37
	Electricity for buildings	£116	£118	£130	£114	£122
	Electricity for transport	£11	£14	£14	£12	£13
	Petrol	£21	£14	£14	£14	£14
	Diesel	£42	£33	£33	£33	£33
	Hydrogen for buildings	£0	£0	£0	£10	£1
	Hydrogen for transport	£0	£1	£1	£2	£1
	Green gas	£2	£5	£2	£2	£5

The annual costs for each scenario to 2050, under the central cost assumptions, are presented in Figure 5-26 (left). The High electrification scenario incurs the largest cost, primarily for the later years, with heat pump capital costs and high electricity usage being a large contribution to this cost. It should also be noted that due to the assumption that the gas grid is no longer viable in 2050, there would likely be an additional cost for gas grid decommissioning in the High electrification scenario. However, the ongoing gas grid operating costs would then be avoided beyond 2050. The annual total scenario cost per capita is presented on the right to allow comparison in more tangible units; this is averaged across all domestic and non-domestic users, so does not represent a consumer bill, and there are important considerations of the most equitable distribution of costs incurred that will need to be addressed. The Decarbonised gas scenario shows a peak 2040 to 2045 due to the roll out of hydrogen infrastructure and hydrogen boilers across London.

Figure 5-26 Annual scenarios costs to 2050 overall (left) and per capita (right)



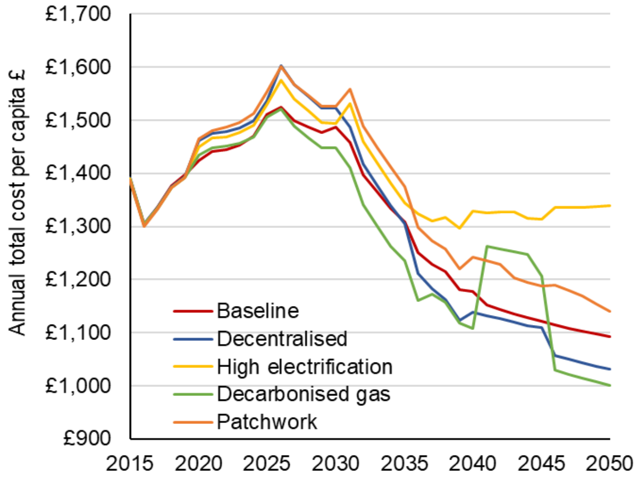
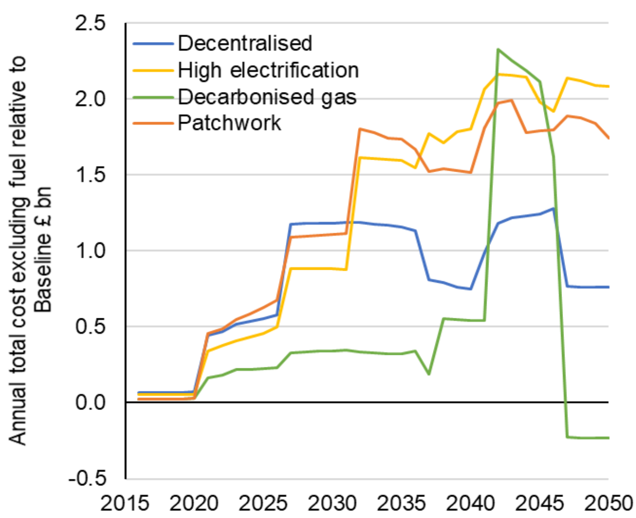
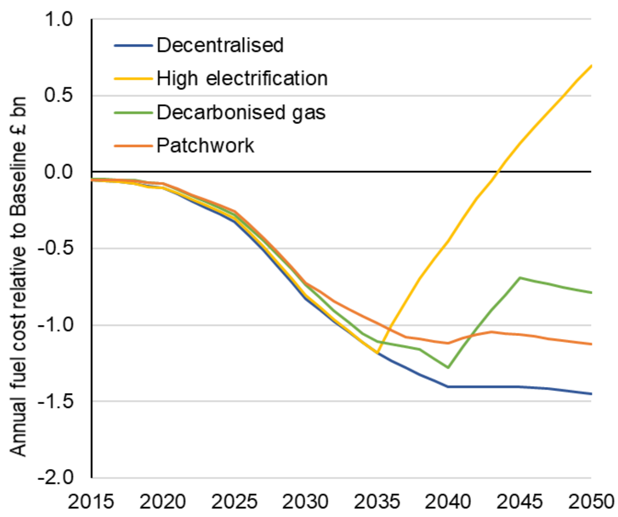


Figure 5-27 shows annual scenario costs relative to the Baseline scenario, also under the central cost assumptions, for infrastructure and building level costs (left) and fuel costs (right). Heat pump levels are the largest driver of building level costs, raising the total cost of the High electrification and Patchwork scenarios, as they include high heat pump uptake. In the Decentralised scenario, the heat network roll-out is the largest infrastructure cost, occurring primarily between 2025 and 2035. The fuel costs depicted in Figure 5-27 (right) are, in most cases, lower than the Baseline scenario, due to the reduced use of petrol and diesel, with conventional vehicles being replaced by more efficient alternatives. In the High electrification scenario increase significantly after 2035 due to the uptake of direct electric heating.

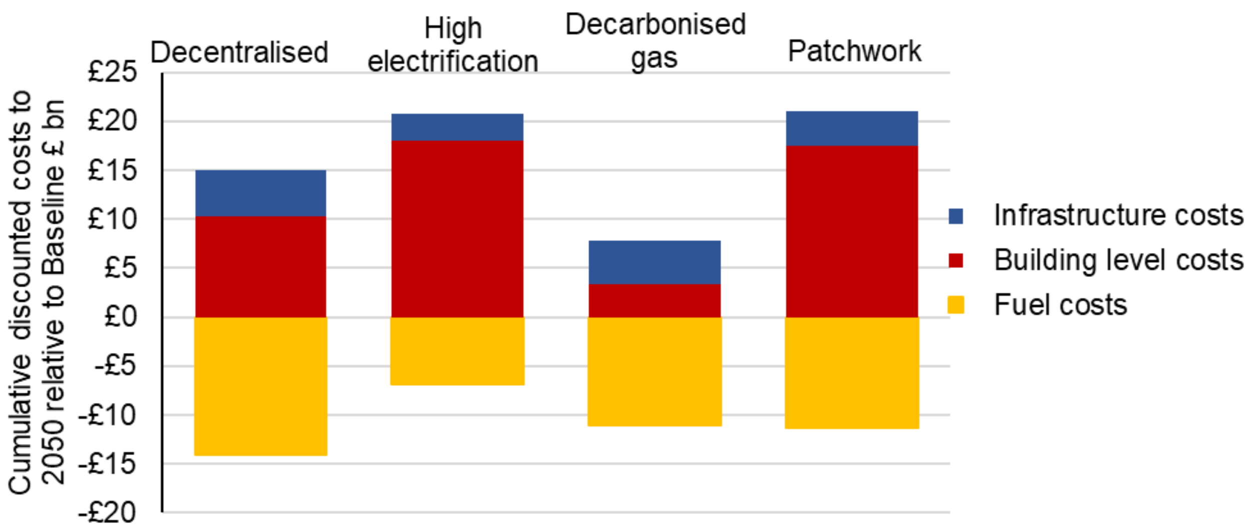
Figure 5-27 Annual scenario costs to 2050 relative to Baseline for infrastructure and building level costs (left) and fuel costs (right)





The cumulative scenario costs to 2050 relative to the Baseline scenario are presented in Figure 5-28. As discussed above, the fuel costs of the scenarios are lower than in the Baseline, predominantly due to the transport fuel efficiency cost savings. The savings would be partially offset by the higher vehicle capital costs, which are outside the scope of this study. It is interesting to note that while the building level costs are highest in the High electrification and Patchwork scenarios, which involve high heat pump uptake, the infrastructure costs are highest in the Decentralised and Patchwork scenarios due to the roll out of heat networks and hydrogen infrastructure.

Figure 5-28 Cumulative discounted scenario costs to 2050 relative to the Baseline scenario



Key outcomes of the cost modelling are as follows:

1. **Fuel costs** form the largest share of the overall costs. The improved efficiency of EVs over ICEs results in a reduced fuel cost for all decarbonisation scenarios relative to the Baseline.
2. **Building level costs** are primarily driven by the level of deployment of heat pumps, given the high capital cost of heat pumps relative to gas or hydrogen boilers.
3. **Infrastructure costs** are primarily driven by the level of deployment of heat networks, followed by EV charging infrastructure and hydrogen conversion.
4. While the investment in the **electricity grid reinforcement** in the High electrification scenario is substantial (£0.9 bn) this makes up a small share (0.3%) of the total cumulative cost to 2050.
5. **Timing:** the majority of the technology and infrastructure roll out occurs from 2025 to 2040 (2045 for the scenarios with hydrogen), and scenarios require a large investment in the range £25-40 bn over this period for building level and infrastructure deployment.

Decarbonised gas scenario has a lower cumulative cost to 2050 under assumptions in this study. This is driven largely by the lower expected cost of hydrogen boilers than heat pumps, and the lower unit price of hydrogen relative to the electricity price assumed. All hydrogen used for heating is assumed to be produced through large-scale SMR with CCS, relying on availability of CCS technology. By 2050 natural gas used in SMR may be more costly if supply is limited, which would increase the cost of hydrogen; this has not been included in the study due to large uncertainty. Production of hydrogen through electrolysis is an alternative approach which would not rely on CCS, and could be used to produce zero carbon hydrogen using renewable sources of electricity. However, current evidence suggests that hydrogen production through electrolysis is likely to be substantially more costly than SMR with CCS, and this option is not studied quantitatively here. For discussion of the risks and uncertainties associated with a hydrogen pathway, please see sections 3.4 and 6.3.

Investment uncertainty sensitivity

A sensitivity on the investment results was completed to understand the uncertainty associated with the outcomes. A summary of the low, central and high investment results is presented in Table 5-5, with more detail available in the accompanying charts workbook.[61] There is the largest absolute uncertainty associated with the fuel costs, as they are the largest contribution to overall costs. The relative contribution of different fuels is shown in Figure 5-29 below.

Table 5-5 Uncertainty associated with the cumulative discounted costs in each scenario

		Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Total cumulative cost	Low	£256	£257	£270	£252	£265
	Central	£278	£279	£292	£274	£287
	High	£299	£298	£311	£294	£308
Central cumulative cost	Building-level	£39	£49	£56	£42	£56
	Infrastructure	£1.8	£6.5	£4.4	£5.8	£5.1
	Fuel	£238	£224	£231	£227	£226
High - low cost difference	Building-level	£0.3	£2.1	£4.5	£0.3	£4.4
	Infrastructure	£0.5	£1.3	£1.0	£1.8	£1.3
	Fuel	£41.6	£37.7	£35.5	£39.9	£37.6
	Total	£42.4	£41.0	£41.0	£42.0	£43.3

High uncertainty in building level costs occurs where building level costs are highest, as in the High electrification and Patchwork scenarios due to high uptake of heat pumps. In the Decarbonised gas scenario, the cost of hydrogen boilers can be estimated with higher confidence, while the cost of producing low carbon hydrogen and repurposing the gas grid is considerably more uncertain. However, there are wider uncertainties around the feasibility of delivering hydrogen safely within the home. Since these uncertainties are difficult to quantify in cost terms, these are considered 'stop-go' uncertainties, where the cost may be prohibitively high[62]. Building level cost uncertainty in the Decentralised scenario is less than High electrification due to the medium uptake of heat pumps, while for infrastructure costs the dominant uncertainty is the capital cost of heat distribution network.

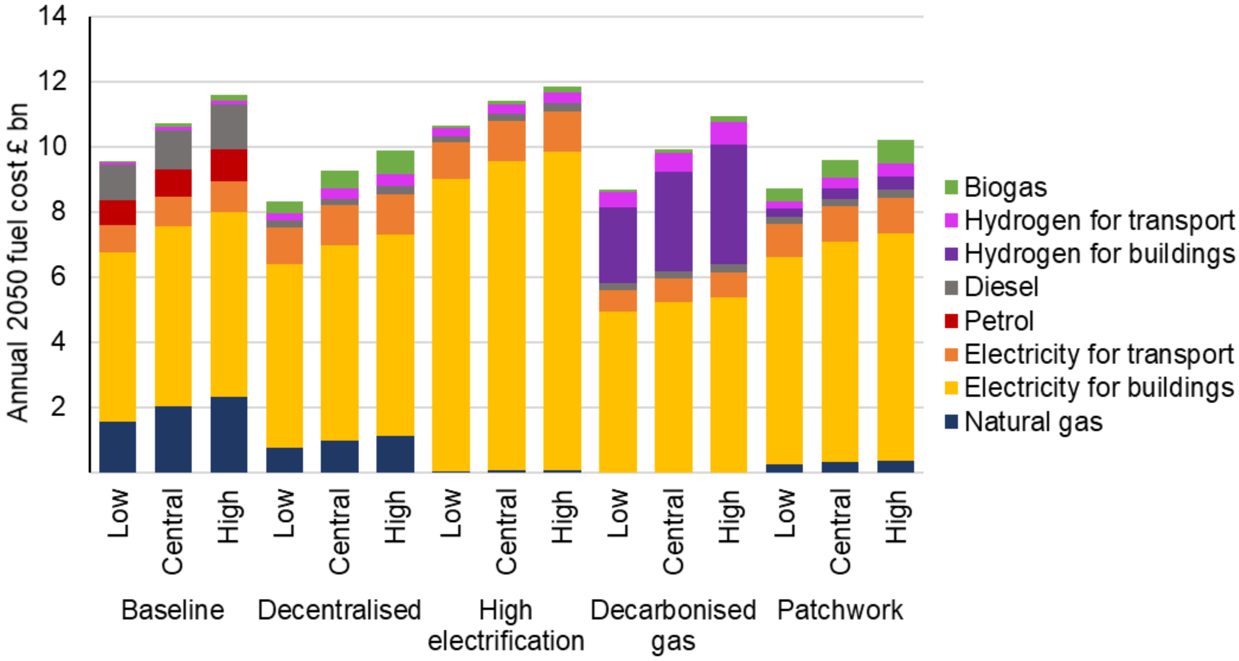
[61] *London's Climate Action Plan* work package 3, accompanying charts workbook, Element Energy 2018
[62] *Cost analysis of future heat infrastructure options*, report for National Infrastructure Commission, Element Energy & E4tech, 2018

Fuel prices

All fuel costs in this study are calculated using assumed retail fuel prices. For natural gas, electricity, petrol and diesel, the retail prices are taken from the HMT Green Book[39]. For hydrogen and biogas prices, the primary sources are the SGI and Royal Society[23].

All fuels have a central case, with low and high sensitivities also included. Figure 5-29 shows the impact of variability in the retail fuel prices in the sensitivities, on the annual 2050 fuel cost for each scenario.

Figure 5-29 Annual scenario fuel cost in 2050, with low, central and high cases



The uncertainty around hydrogen retail prices is significantly larger than that around more conventional fuels, so the Decarbonised gas scenario cumulative fuel cost varies more between the low and high cases than the other scenarios, with the exception of the Baseline scenario, as shown in Table 5-5.

The total transport fuel cost is significantly lower in the four scenarios by 2050 than in the Baseline scenario. This is due, in part, to the high retail fuel price of petrol and diesel, a significant portion of which is tax. It should be noted that, if petrol and diesel no longer contribute to London's transport fuel mix in 2050, the government may seek to apply taxes to new transport fuels, such as hydrogen and electricity. This potential additional tax has not been included in this study, but could have a significant bearing on the transport fuel costs in the later years. Fuel duty is currently levied at 58 p / litre for petrol and diesel, making up approximately 45% of the overall cost. Adding a levy on EV fuel of 3.5 p/kWh from 2035 to 2050 (which would represent an 18% addition to the domestic electricity cost over that period), would raise £1.5 bn in cumulative discounted terms, sufficient to meet the total electricity system upgrade costs in the High electrification scenario of £1.4 bn.

For a discussion of the cost and impact to consumers, please see section 6.1.

5.5 Patchwork scenario sensitivity

A sensitivity on the Patchwork scenario has been completed to understand the outcome without the hydrogen backbone described in section 3.4. This sensitivity allows an understanding of the impact if the backbone is found to be uneconomic or unfeasible. In this sensitivity, transport comprises lower FCEV uptake, and heat networks and industry are assumed to no longer have any access to hydrogen. As shown in Table 5-6, without the hydrogen backbone, the Patchwork scenario annual emissions are 0.7 $MtCO_2$ higher in 2050, and the costs are around £0.5 bn lower (£1 bn undiscounted).

Table 5-6 Summary of the Patchwork scenario results, with and without the hydrogen backbone. Costs are cumulative and discounted.

Scenario Summary	Patchwork	Patchwork (No H_2 grid)
Annual 2050 emissions $MtCO_2$	4.4	4.7
Cumul. emissions to 2050	600	604
Total Cost £ bn	£287.5	£287.1
Building level costs	£56.1	£56.1
Infrastructure costs	£5.14	£5.09
Fuel costs	£226.3	£225.9

For further details of the Patchwork scenario sensitivity, please see the charts workbook[63], where the full cost breakdown can be found. There is currently insufficient evidence around the cost and impact of the hydrogen backbone in London to draw a robust conclusion on the cost-effectiveness relative to other decarbonisation options. It is recommended that a more detailed feasibility study could be completed around this option.

[63] London's Climate Action Plan work package 3, accompanying charts workbook, Element Energy 2018

5.6 Scenario results summary

Table 5-7 Summary of emissions and investment results

Scenario Summary	Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Annual 2050 emissions $MtCO_2$	18.5	6.9	3.4	3.5	4.4
Cumul. emissions to 2050	820	626	597	617	600
Total Cost £ bn	£278	£279	£292	£274	£288
Building level costs	£39	£49	£57	£42	£56
Infrastructure costs	£1.8	£6.5	£4.4	£5.8	£5.1
Fuel costs	£238	£224	£231	£227	£226

Decentralised

- DH deployment is limited to ≈25% of the building stock; medium levels of heat pumps are insufficient to decarbonise the remaining heat, so the scenario fails to decarbonise heat as fully as the other scenarios.
- Transport is dominated by BEVs, although FCEVs are used for some vehicles (29% by energy).
- The cost of this scenario is relatively low, with a large share of the building level costs from heat pumps (£25 bn) and infrastructure costs from heat network deployment (£7 bn).
  The fuel cost is lowest for this scenario due to high PV and heat network CHP, resulting in electricity production, and increased heating efficiency due to extensive use of waste and secondary heat sources.

High electrification

- The heat and transport sectors are almost entirely decarbonised by 2050, with replacement of natural gas from all homes, and petrol and diesel from all transport, predominantly with electricity.
- Transport is dominated by BEVs, although FCEVs are used for some vehicles (29% by energy).
- The energy efficiency retrofit limit leads to a substantial uptake of direct electric heating in buildings not suitable for heat pumps. This has a significant impact on the electricity grid resulting in £2.4 bn grid upgrade cost, and high fuel costs.
- This is found to be the most costly scenario overall, mainly due to the large capital cost of heat pumps. An advantage of this scenario is avoiding reliance on unproven technologies, lowering the risk.

Decarbonised gas

- The heat and transport sectors are almost entirely decarbonised by 2050, with phasing out of natural gas entirely. However, the cumulative emissions remain higher due to the late switchover of the gas grid, despite the inclusion of earlier hydrogen blending and transport decarbonisation.
- Under the cost assumptions made, the scenario incurs lower cost to 2050 than the other decarbonisation scenarios due to the lower cost of hydrogen boilers relative to heat pumps. Additionally, hydrogen from SMR with CCS is assumed, based on the literature sources described, to be less costly per kWh than electricity. Infrastructure costs are larger in this scenario, but do not offset the lower building-level costs.
- Scenario relies on the development of low cost hydrogen production using SMR with CCS by 2040, the viability of delivering hydrogen safely to buildings and consumer acceptance of this. There are significant uncertainties around these requirements and this is a higher risk scenario than the other scenarios.

Patchwork

- The Patchwork scenario is decarbonised sufficiently by 2050 by high heat pump uptake, medium heat networks, high green gas and hydrogen blending and a hydrogen 'backbone' grid from 2040; the backbone serves a share of large industry, DH and transport, allowing a higher share of FCEVs.
- This scenario is found to be more costly than the Decarbonised gas scenario, but less costly than the High electrification scenario, the other two scenarios which reach sufficiently deep decarbonisation.
- The risk associated with this scenario is lower than that of the Decarbonised gas scenario, as it does not rely heavily on unproven technologies. Hence, it is considered a more deliverable, mixed scenario.

6 Implications and discussion

6.1 Consumer cost impacts

It is critical to understand the impact of each of these scenarios on the consumer, both in terms of cost and quality of service. Although all investments will ultimately be paid for by consumers (as citizens), some are paid for directly, while others are paid for through private investment or by government, and the cost recovered through service charges or taxes.

In this analysis, we have defined the "direct consumer costs" as those which is likely to be paid for by consumers at around the time the cost is incurred more widely. As shown in Table 6-1, this is assumed here to include fuel costs, building-level costs such as heating systems and energy efficiency, and home or workplace electric vehicle charge points. All other costs are categorised here as "indirect costs", which are assumed to be investments made by public or private sector and socialised or recovered through service charges or taxes over a longer period (likely decades). This is most likely the case for large infrastructure investments in the electricity and gas networks, public charging infrastructure and heat network capital costs (which would be recovered through heat standing charges and/or heat sales over the lifetime of the network).

The separation of the costs into these two categories is not meant to imply a fundamental and unchanging difference in the types of investment described, and the separation is not clear-cut in some cases. For example, while building level costs in new buildings would initially be paid for by the property developer, it is assumed that they would pass this cost directly to the consumer through the building purchase cost, whether that be paid outright or through a mortgage. This is categorised here as a direct consumer cost, where in the case of a mortgage the cost would be paid initially by the mortgage lender, and recovered from the consumer over many years. Furthermore, the allocation of costs between the direct and indirect categories would be altered through any subsidy, such as a capital grant or loan, which would reduce the direct consumer cost and increase the indirect cost.

A summary of the allocation of the discounted cumulative cost between the direct consumer cost and indirect cost categories is given in Table 6-1. For the annual split of direct and indirect consumer costs over time, please see the accompanying charts workbook[15].

Table 6-1 Discounted cumulative cost to 2050, split between direct consumer costs and private or government costs

Costs £ bn	Cost description	Baseline	Decentralised	High electrification	Decarbonised gas	Patchwork
Total consumer		**£277**	**£274**	**£289**	**£269**	**£284**
Total non-consumer		**£1**	**£5**	**£3**	**£5**	**£4**
Direct consumer costs	Fuel for buildings	£163	£162	£169	£165	£165
	Fuel for transport	£74	£62	£62	£62	£62
	Building level costs	£39	£49	£57	£42	£56
	Private vehicle charging infrastructure	£0.7	£1.3	£1.3	£0.8	£1.2
Indirect costs	Heat network system costs	£0.7	£4.1	£0.7	£2.7	£2.7
	Elec. system upgrades	£0.0	£0.1	£1.4	£0.0	£0.1
	Gas networks	£0.0	£0.0	£0.0	£1.2	£0.1
	Public vehicle charging infrastructure	£0.3	£0.9	£0.9	£0.7	£0.8

Figure 6-1 shows the average annual cost of heating in 2050 for four heating systems, including heating system capital, maintenance and fuel cost, for a typical domestic consumer. The assumed heat demand per domestic building is 8,400 kWh per year, which is the average across all existing domestic buildings assumed in 2050 (under the high energy efficiency scenario). Existing dwellings which have not had energy efficiency retrofit measures have a higher annual heat demand of 11,130 kWh in 2050 and will be unable to select low temperature heating systems such as heat pumps.

It is interesting to note that heat pump and hydrogen boiler annual costs are relatively similar in the central and high fuel price cases. However, due to the greater uncertainty around the hydrogen price, the variation on hydrogen heating cost between the low and high sensitivities is larger. The direct electric heating cost shown here assumes the same electricity price as in the heat pump case. A home without energy efficiency retrofits using direct electric heating would face an additional 33% increase in fuel bill (£522 per year) to cover their higher heat demand. A critical policy challenge will be ensuring customers on direct electric heating have access to lower tariffs or other means to reduce heating costs, particularly in the case of households at risk of fuel poverty.

It may be necessary for the public sector to at least partially offset any increase in household heating cost, in order to incentivise uptake of low carbon technologies and protect consumers. For example, the domestic RHI currently provides a subsidy of 10.49 p/kWh of renewable heat for ASHPs. If this rate still applied, it would offset £548 of heating cost annually for the typical household, bringing the central cost assumption down to £555 annually (less than the £732 for a gas boiler). The form of incentives, as well as their value, may change over time. For example, future renewable heat incentives could employ partial upfront grants to address the barrier of high capital costs. Taxes are another mechanism to drive decarbonisation and fund infrastructure requirements or subsidies, such as the example of a new levy on EV fuel described in section 5.4.

Figure 6-1 Average annual domestic heating cost in 2050 for the four main heating technologies

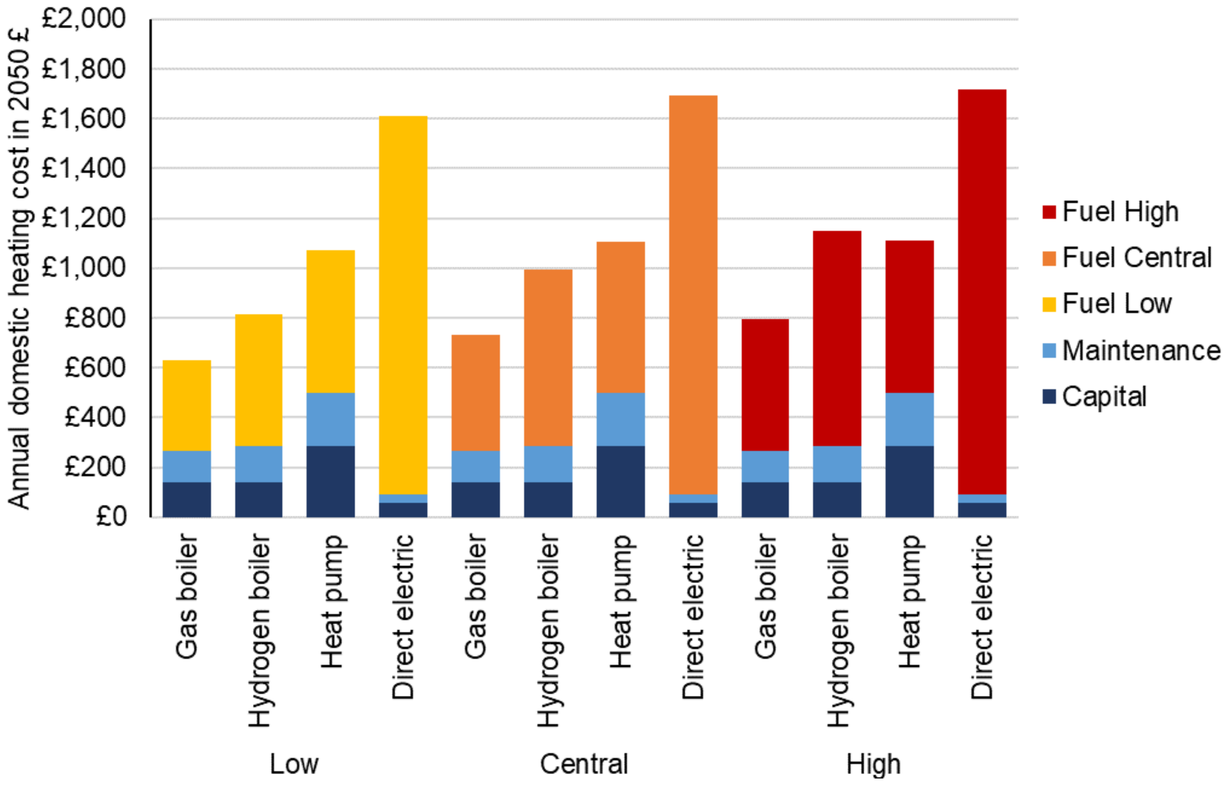
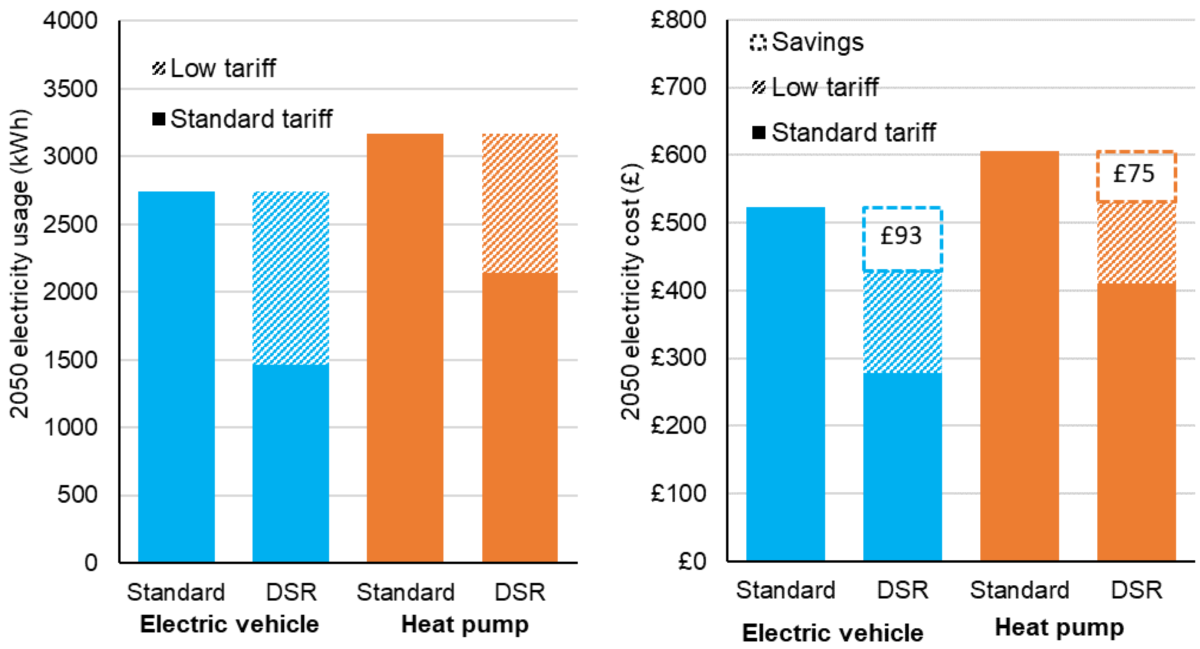


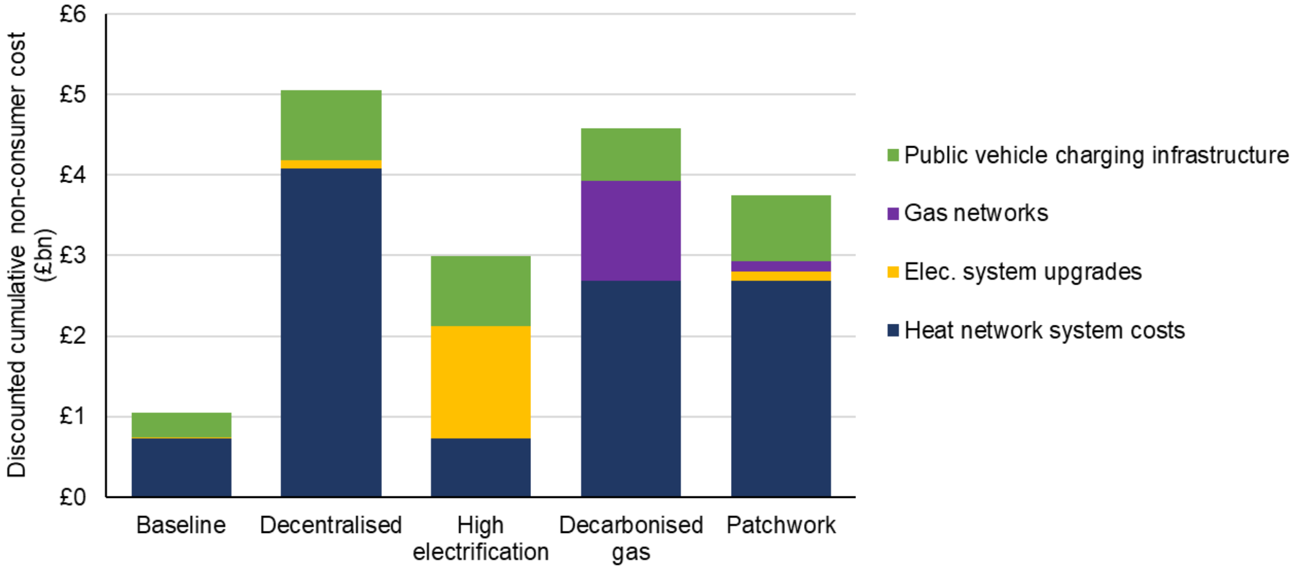
Figure 6-2 presents the 2050 electricity usage and cost for an electric passenger vehicle and for a heat pump. The EV is assumed to travel 20,000 km per year and is charged fully once every four days from a 7 kW charger. The heat pump supplies the average existing domestic home and is operated with additional thermal storage. If all electricity is consumed on the central domestic retail tariff, the yearly fuel costs are £523 and £615 for the electric vehicle and heat pump, respectively. To estimate the financial benefit of participating in a DSR scheme, we have assumed a two-hour low-tariff DSR period occurs each day, allowing participating consumers to access electricity at the industrial retail price assumed in the low fuel price sensitivity, a saving of 7.3 p/kWh. This low cost DSR period would occur when demand is very low (for example in the middle of the night) and likely exist in conjunction with a high cost period at the time of peak demand. Consumers who conscientiously participate in the scheme, taking advantage of the low cost period while avoiding usage during the high cost period, would save £93 on their yearly EV electricity bill and £75 on their yearly heat pump electricity bill, as shown in Figure 6-2 (right). Under these assumptions, the heat pump electricity bill is still higher than the 2050 natural gas bill, although the level of savings achievable will depend on the details of the DSR scheme, including the daily and seasonable availability of the low tariff and the rate of savings, as well as the adoption of enabling technology by the consumer, in this case a smart EV charger and additional thermal storage tank.

Figure 6-2 2050 consumer benefit of a variable (DSR) electricity tariff for an EV and heat pump with additional thermal storage. Electricity usage (left) and cost (right).



In Figure 6-3, the discounted cumulative scenario indirect costs are presented. These costs are all associated with infrastructure development, and their total magnitude is substantially smaller than the direct consumer costs. However, there are significant challenges in deployment and financing of the infrastructure that require broad coordination. Heat networks form the majority of the indirect costs for the Decentralised scenario, while electricity system upgrades are a significant share only in the High electrification scenario.

Figure 6-3 Components of the cumulative indirect cost to 2050, which must be financed privately or by government.



6.2 Safeguarding

Since physical space is a limited resource in many areas of London, it is important that planners have an understanding of the likely requirement to safeguard land in particular areas for the development of energy infrastructure.

As described in the earlier sections of the report, this study has considered the spatial deployment of a variety of energy technologies and the associated infrastructure. This includes identification of the areas most suitable for heat network deployment; an understanding of the variation in the mix of different building types across London and the implications for spatial deployment of low carbon heating systems such as heat pumps; at a higher level, requirement for electric vehicle charging and hydrogen vehicle refuelling stations; and a consideration of two different spatial approaches to hydrogen network rollout. This analysis allows us to provide some insight into the safeguarding requirements for several key types of energy infrastructure.

In this section, we present a high-level assessment of the safeguarding requirements of the following:

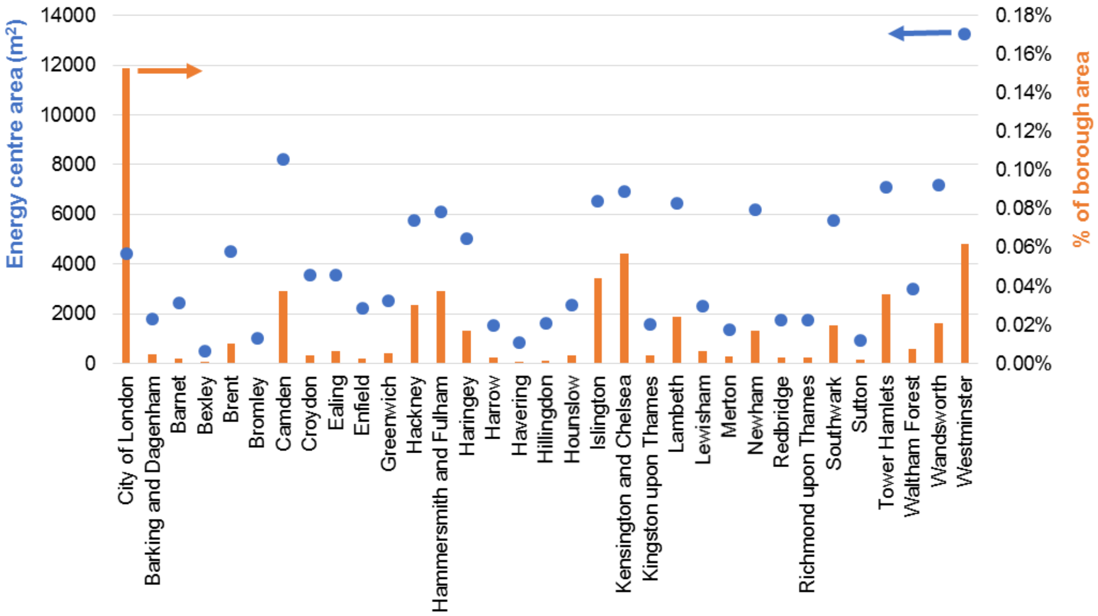
- Heat network energy centres
- Hydrogen conversion (full conversion and 'backbone' cases)
- Transport charging/refuelling infrastructure

Heat network energy centres

Heat networks are most economical when the heat density is high which usually coincides with the areas where space is scarce. Figure 6-4 represents a high-level estimate of the area required to house the energy centres providing heat to each borough (left axis, blue dots) and this area as a fraction of the total borough area (right axis, orange bars). The case shown is the High DH scenario in 2050, when heat networks provide 22% of London's heat demand. To develop these estimates, an area requirement of 100 m^2 per MW peak heating capacity has been assumed, based on several existing energy centres in London whose size varies between 75 and 100 m^2 per peak MW_{th}[64].

[64] Bunhill Energy Centre in Islington, ≈4 MW_{th} peak, estimated 300 m^2, http://www.decentralized-energy.com/articles/print/volume-15/issue-1/features/city-heating-schemes-leading-the-uk-chp-awards.html
QEII Olympic Park Energy Centre, ≈50 MW_{th} peak, estimated 5000 m^2, http://www.queenelizabetholympicpark.co.uk/the-park/attractions/around-the-park/energy-centre

Figure 6-4 Area required for heat network energy centres by borough (High DH scenario)



The largest estimated required area is for the borough of Westminster (13,000 m²). The largest fractional space requirement is for the City of London which, on the basis of this simple calculation, would need energy centre(s) covering a space equal to 0.15% of its area. Although this is a significant land area, it is important to note that the heat network energy centre(s) will consolidate the many smaller boilers in plant rooms currently located inside individual buildings, so could result in a net increase in developable area (and potentially, the plant rooms of large commercial buildings could be used to house a heat network energy centre). Further, this space does not necessarily need to be located within the City of London itself except where local waste heat is being recovered. Nonetheless, this is clearly a key consideration for safeguarding.

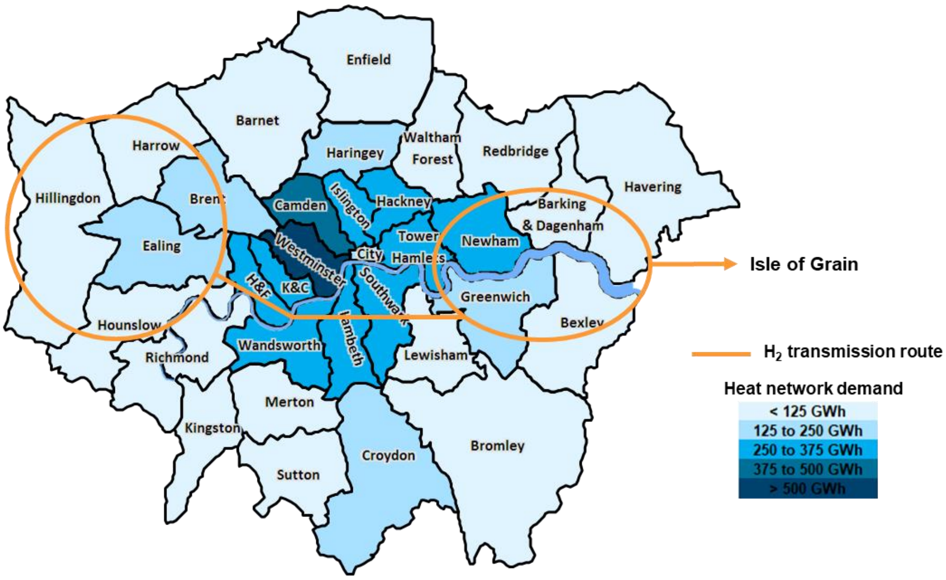
We note that situation of the energy centre close to the point of use is likely to be the case during the nucleation stage of heat network development, for economic reasons. However, as heat networks continue to expand, formerly separate networks may become connected and it will be possible to produce heat at larger 'energy hubs' that may be further removed from the densest areas of London. In some scenarios these hubs may be connected to the hydrogen backbone discussed further in the next section.

Hydrogen conversion

In the Decarbonised gas scenario (see section 3.4 above) London's gas distribution network is re-purposed to deliver hydrogen. In this case, a new high-pressure transmission network would be built to supply hydrogen to the distribution network and to large gas-users who require high pressure delivery. The Patchwork scenario includes the option of a 'backbone' hydrogen network (also described in section 3.4) that would follow a similar route to the transmission network in the full conversion case. The backbone would distribute hydrogen to the largest users while avoiding the infrastructure cost of converting the entire gas distribution network. A further potential advantage of this option relative to full conversion is that it may be possible to avoid extensive infrastructure development in central London, where this would be most disruptive and costly. This is contingent upon the backbone hydrogen network being able to serve sufficient demand while following a route minimising sections through central London.

Figure 6-5 presents a conceptual route the transmission network or hydrogen backbone could take, based on a high-level assessment of the areas with a significant share of large industrial heat demand and significant potential for heat network development. This route takes the form of an "east-west corridor" connecting the Isle of Grain and Thames Estuary to the east of London, and potentially links across to the west along the Thames Valley.

Figure 6-5 Conceptual route of hydrogen transmission network or 'backbone'



The Isle of Grain is located 60 km east of London and hosts National Grid's Grain LNG terminal through which 20% of the UK's natural gas is currently imported. The site contains several gas shipping terminals, regasification and gas blending facilities and substantial natural gas storage.

This site could play an important role in London's infrastructure in the case of full hydrogen conversion or a hydrogen backbone, either as a site to produce hydrogen through SMR with CCS from imported natural gas, to transport CO_2 (in the case of hydrogen production through SMR with CCS on-site or elsewhere in or near London), or as a site to import hydrogen (which may be produced elsewhere in the UK or internationally). In the case of CO_2 transport, this could potentially involve delivery of CO_2 offshore via pipelines connected directly to storage sites off the coast of East Anglia[65] or the refilling of empty LNG tankers (supplying gas feedstock for SMR and other uses) with waste CO_2 for storage in the North Sea or further afield[66].

In either case, significant repurposing or new construction would be required, but this offers a potential route for London to develop a hydrogen production/import system without necessarily relying on connection to hydrogen production facilities in other parts of the UK.

In the "east-west corridor" view, the transmission pipeline would enter the east side of London near the Thames Estuary. The boroughs of Bexley, Newham, Havering, and Barking and Dagenham were identified in the London Energy Plan[67] as containing a significant proportion of London's industrial demand. A second cluster of significant industrial demand is present in Hillingdon, Hounslow, and Brent, which could form the western branch of the transmission network or hydrogen backbone. The boroughs in the map in Figure 6-5 are coloured to indicate the level of heat network demand in each in 2050 (medium uptake level). Energy centres within Inner London, for example in Southwark, Lambeth, and Wandsworth could also be connected to the backbone as it travels between the industrial clusters. These energy centres could become 'energy hubs' for a wider area as heat networks become interconnected and could eventually supply the central London boroughs which are more highly space-constrained but require large energy centres as noted above.

The creation of energy hubs would allow collocation of several interdependent energy technologies. The heat network energy plant could make use of the hydrogen connection to produce both heat and electricity from fuel cell CHPs. The electricity production could be combined with battery storage and/or hydrogen production

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[65] Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 targets, E4tech for CCC, 2015.
[66] Grain LNG Terminal stakeholder consultation
[67] Data collected during preparation of the Zero Carbon Tool, https://maps.london.gov.uk/zerocarbon/

through electrolysis to provide grid balancing, frequency response, and peak reduction services to the electricity grid. Storage facilities for both heat (hot water) and hydrogen would further enhance system flexibility.

Transport Infrastructure

Hydrogen is expected to supply larger and long-range vehicles in all scenarios. In the later years of the scenarios with higher hydrogen deployment (Decarbonised gas and Patchwork), the majority of hydrogen is assumed to be provided by large-scale SMR situated outside of London (or potentially in less dense outer boroughs). But when the hydrogen grid is not present, hydrogen will need to be produced within London although not necessarily at the point of use.

All HRS must have some hydrogen storage and a dispenser. HRS designed for smaller vehicles dispense hydrogen at a higher pressure and therefore also contain a compressor and pre-cooler which are not necessary for the lower pressures used by buses and HGVs. This plant requires between 100 and 150 m^2 at existing HRS, in addition to the forecourt refuelling space[68].

Additional space will be needed at the HRS or off-site for electrolysis or SMR plant. Hydrogen production facilities for a single dispenser would add a further 25 to 50 m^2 to the on-site space requirement, but the overall space needed would be reduced if hydrogen was produced in fewer, centralised locations and delivered to the HRS. This is particularly convenient for HRS that may be located at small petrol stations in Inner or Central London.

In the Decentralised and High electrification scenarios, electrolysis is the dominant production method after 2035. 50% of London's demand is assumed to be supplied from outside London while the remainder is produced using 2 MW electrolysers situated in various locations throughout Outer London. Up to 70 such electrolysers would be needed in 2050 to supply 50% of London's transport demand for hydrogen. Systems available today would require between 100 and 200 m^2 for each 2 MW electrolyser, but further economies of scale are likely to be realised as large-scale systems are implemented more widely. These can be flexibly located to suit electricity constraints and minimise the delivery distance to different parts of London.

Additional infrastructure will be required for electric vehicles, including facilities for slow (i.e. overnight) charging as well as rapid charging. Where off-street parking is available at homes and workplaces, the addition of EV chargers to the building electricity connection is straightforward. It is more challenging to provide EV charging in areas where large numbers of vehicle are parked on-street overnight. A 2015 study estimated that by 2025, as many as 150,000 electric cars, taxis, and LGVs will require an on-street solution for overnight charging[69]. Several boroughs including Hounslow, Lambeth, and Westminster are currently trialling lamppost charge points[70]. Lamppost chargers or other on-street solutions will need to be deployed widely by 2050 to accommodate the 60% of London's BEVs that will not have access to off-street parking, anticipated to be over 500,000 vehicles.

Rapid chargers are another solution for vehicles without access to off-street parking and charging. 125 rapid chargers are currently available in London and TfL has announced that at least 300 will be present by 2020, rising to over 600 in the years following. Rapid chargers do not individually require more space than a parking spot, but batteries or supercapacitors are likely to be situated on-site when multiple rapid chargers are located together. Although relatively little space outside of the parking spots is required, both on-street and rapid charging are likely to increase parking pressure. Due regard will be required to mitigate adverse impacts on residents, and particularly those who have no demand for EV charging.

[68] Based on size of ITM Power Hydrogen stations, http://www.itm-power.com/h2-stations
[69] Electric Vehicle Uptake and Infrastructure Impacts Study, Element Energy for TfL, 2015.
[70] Ubitricity lamppost trials, https://www.ubitricity.co.uk/unternehmen/newsroom/lambeth-lampposts-electric-vehicle-charging-stations/, accessed May 2018.

6.3 Risks and uncertainty

Whilst the emissions reductions achieved and investment required for each scenario are important factors to inform decision-making, the level of risk and uncertainty associated with each scenario is also critical. The key risks are presented in Table 6-2, along with the risk bearer and potential mitigating actions.

Table 6-2 Summary of key risks associated with each scenario

Risk Description	Risk bearer	Risk type	Policies to reduce risk and increase effectiveness
Baseline			
Scenario achieves insufficient carbon reductions	All	Climate	
Decentralised			
Expected heat network demand does not materialise, leading to lower than expected revenues to developer. Competing technologies, dependent on policy, contribute to this risk.	Private or government	Financial	Consumer incentives & connection policy, guarantees
Natural monopoly: consumers locked into high energy bills once connected, or risk of poor quality of service for consumers connected to heat networks without some form of regulation.	Consumer	Financial, service	Regulation on price and quality of service
Low consumer acceptance and understanding of heat networks leads to low connection rates.	Consumer, government	Climate	Information campaigns
Policy implemented to address the above issues is unsuccessful and the targeted level of heat network deployment is delayed or not achieved.	All	Climate	
High electrification			
Reduced demand on gas grid results in high unit gas price to remaining consumers on gas, as operating and maintenance costs spread over small base.	Private or consumer	Financial	
Required electricity grid upgrades cannot happen fast enough, restricting heat pump and EV deployment.	Private, Consumer	Climate	Flexible regulation to allow more advanced planning
High electricity costs to consumers to fund substantial upgrades to electricity grid.	Consumer	Financial	Price regulation
High electricity costs for consumers with direct electric heating, especially those in less efficient buildings which are unsuitable for heat pumps.	Consumer	Financial	Policies for fuel poor. Max energy efficiency implementation
Increased electricity generation capacity requires either significant investment in national generation or reliance on energy from abroad, impacting energy security.	Government	Energy security	Policy supporting renewable generation
Consumer acceptance: reluctance of owners or landlords to accept heat pumps due to visual or noise concerns or perception of poor service.	Government, private	Climate	Quality assurance, regulations and incentives
Capital costs of heat pumps remain high, leading to high heating costs for consumers.	Consumer	Financial	Financial subsidies, supply chain support/investment

Poor quality heat pump installation leads to poor performance of technology.	Consumer	Service	Quality assurance programmes & training
Behaviour change required to use heat pumps results in perception of lower quality of service to consumers.	Consumer	Service	Training & information programmes
Policy implemented to address the above issues is unsuccessful and the targeted level of heat pump deployment is delayed or not achieved.	All	Climate	
Decarbonised gas			
Large-scale hydrogen production using SMR and CCS is not available at viable cost by the time required to implement this scenario, leading to delays in emissions reduction.	All	Climate	Policy support for trialling & investment in research
Delivery of hydrogen to existing buildings cannot be proven to be safe at viable cost by the time required to implement this scenario, leading to delays in emissions reduction.	All	Climate	
Reliance on natural gas import for hydrogen production using SMR impacts energy security.	Government	Energy security	
Some consumers do not accept hydrogen as a safe and viable alternative to gas, leading to delays in rollout.	All	Climate	Evidence & information campaigns
Consumers do not accept hydrogen as a safe and viable alternative to gas, leading to a large share of consumers using alternative technologies (e.g. heat pumps).	Consumer, Private, Government	Financial	
Consumers perceive the hydrogen switchover and appliance replacement as inconvenient and leading to a lower quality of service.	Consumer	Service	Quality assurance standards
Policy implemented to address the above issues is unsuccessful and the targeted level of hydrogen deployment is delayed or not achieved.	All	Climate	
Patchwork			
The Patchwork scenario, comprising a mix of the decarbonisation options in the above scenarios, contains many of the risks noted, but generally at a reduced level due to the combination of energy sources and technologies deployed.			
Hydrogen backbone may not be economically feasible in London due to small industrial gas demand. The backbone would also be less economic without the development of large scale SMR + CCS hydrogen production. The sensitivity presents the scenario without this backbone, and there is not a large impact on the emissions results.	Private or government	Climate	Studies commissioned to assess the feasibility and economics
All scenarios			
Vehicle capital costs remain high for BEVs and FCEVs. If consumers are obligated to switch to EVs, they incur this high cost, and otherwise there is a risk to achieving climate goals.	All	Financial, Climate	Financial subsidies, new vehicle regulations
Level of energy efficiency assumed does not materialise	All	Climate	Strong energy efficiency policy

6.4 Low regrets actions and key decision points

Due to the urgency of the required emissions reductions and the risks outline above, thought must be given to the critical policies and timepoints by which decisions must be made. Steps must also be taken early, to ensure all scenarios remain feasible until an informed decision can be made.

Low regrets actions for the short and medium term

There are several policy actions that could be taken immediately, either locally or nationally, to support technologies at the minimum levels present in all scenarios and to enable a decision on the preferred scenario in the late 2020s. These low regrets actions entail significant activity from 2020, meaning that decisions on the form of the supporting policy need to be made in 2018-19.

- **Energy efficiency bringing 70% of London's buildings to EPC C or above by 2030**

  The extensive deployment of building energy efficiency measures, covering heat, lighting and appliances, reduces energy use and the cost of energy to consumers regardless of the scenario ultimately chosen. The resulting decrease in building electricity demand for lighting and appliances also facilitates the uptake of heat pumps and electric vehicles by easing pressures on the electricity network. Rapid uptake of energy efficiency measures is difficult to achieve due to their high initial capital cost, in-home disruption, long payback times, and the frequent misalignment of incentives between landlords and tenants. This effort is therefore likely to involve fiscal incentives, local government-initiated programmes to support some market sectors, and the introduction of minimum energy standards for all buildings.

- **Rollout of heat networks to an additional 70,000 homes by 2025**

  All scenarios considered in this report include at least 100,000 homes connected to district heating by 2025, an increase of 70,000 over current levels. These heat networks should be deployed in the most cost-effective locations and make use of London's valuable waste heat. High capital cost and project complexity are the main barriers to heat network deployment; reaching the level of uptake proposed here will require the mechanisms for successful consumer engagement, stakeholder collaboration, and scheme financing to be developed. The experience gained from early deployment of heat networks will provide information on the cost and viability of deployment at scale, and will thereby help to inform the decision on London's preferred long-term decarbonisation pathway. Financial and logistical support, supply side training, and some form of price regulation ensuring fair outcomes for consumers are likely to be needed to realise this level of heat network deployment. Consideration should also be given to heat zoning for networks in new build areas, where consumers are obligated to connect where practicable, or excluded from other technology subsidies.

- **Deployment of heat pumps in more than 300,000 buildings by 2025**

  A step-change in the level of heat pump uptake between now and 2025 is required in three of the four decarbonisation scenarios studied. These scenarios include at least 300,000 heat pumps deployed by 2025, compared with the very low levels of current deployment. 250,000 of these heat pumps are likely to be in new buildings while 50,000 will be deployed in existing buildings. Heat pump uptake is primarily limited by the high capital cost, relatively under-developed supply chain and lack of consumer familiarity. More widespread deployment of heat pumps in the 2020s will enable early assessment of consumer acceptance, the required level of financial support, and the effectiveness of supporting policy. The level of cost reduction achieved through supply chain improvements and manufacturing economies of scale will also affect London's preferred path. Heat pump deployment could be targeted initially towards new buildings, where no additional building renovation is required, and in off-gas buildings where fewer low carbon options are available and heat pumps will have the highest impact in carbon reduction terms. However, some substantial deployment of heat pumps in existing on-gas dwellings will also be important to understand the consumer attitude towards the technology in that segment, in order to assess the viability of the highest heat pump deployment pathways. Deployment of heat pumps in new buildings can be driven by building regulations. A step-change in the level of deployment of heat pumps in existing buildings is likely to require a reformulation of the Renewable Heat Incentive (RHI) (or another fiscal incentive scheme) to provide a more attractive offer to consumers, information campaigns to increase awareness of the technology, and installer training.

- **New-build regulations mandating high efficiency and low carbon heating**

  The London Plan mandates high energy efficiency and carbon standards for new buildings. These measures are needed to avoid locking in higher than necessary energy demand and fossil-based heating for a generation of new buildings. Misalignment of incentives between developers and future residents, and a lack of consumer familiarity with low carbon systems, present obstacles to the construction of high efficiency buildings. New buildings are a key early market for both heat pumps and heat networks, and achieving the low regrets levels of deployment of these technologies described above will require most new buildings to be served using one of these technologies from 2020 onwards. The Mayor’s zero carbon standard already encourages the uptake of building-level heat pumps and district heating, and should continue to be monitored and strengthened.

- **Coordination of EV charging infrastructure deployment**

  Plug-in hybrid and battery electric vehicles make up around 10% of passenger vehicles in all scenarios by 2025, and will rely on a London-wide network of home, workplace, public, and rapid charge points. In areas without off-street parking, significant on-street charging infrastructure is required to avoid limiting the uptake of electric vehicles. Several deployment schemes are already under way, and continued coordination and logistical and financial support for the rollout of these charge points will facilitate the uptake of low emissions vehicles, especially in areas of London with limited off-street parking. Coordination efforts should ensure that public charge points (whether installed by private companies or the individual boroughs) are compatible with the widest possible range of vehicles and that impacts on the electricity grid can be managed.

Key decision points

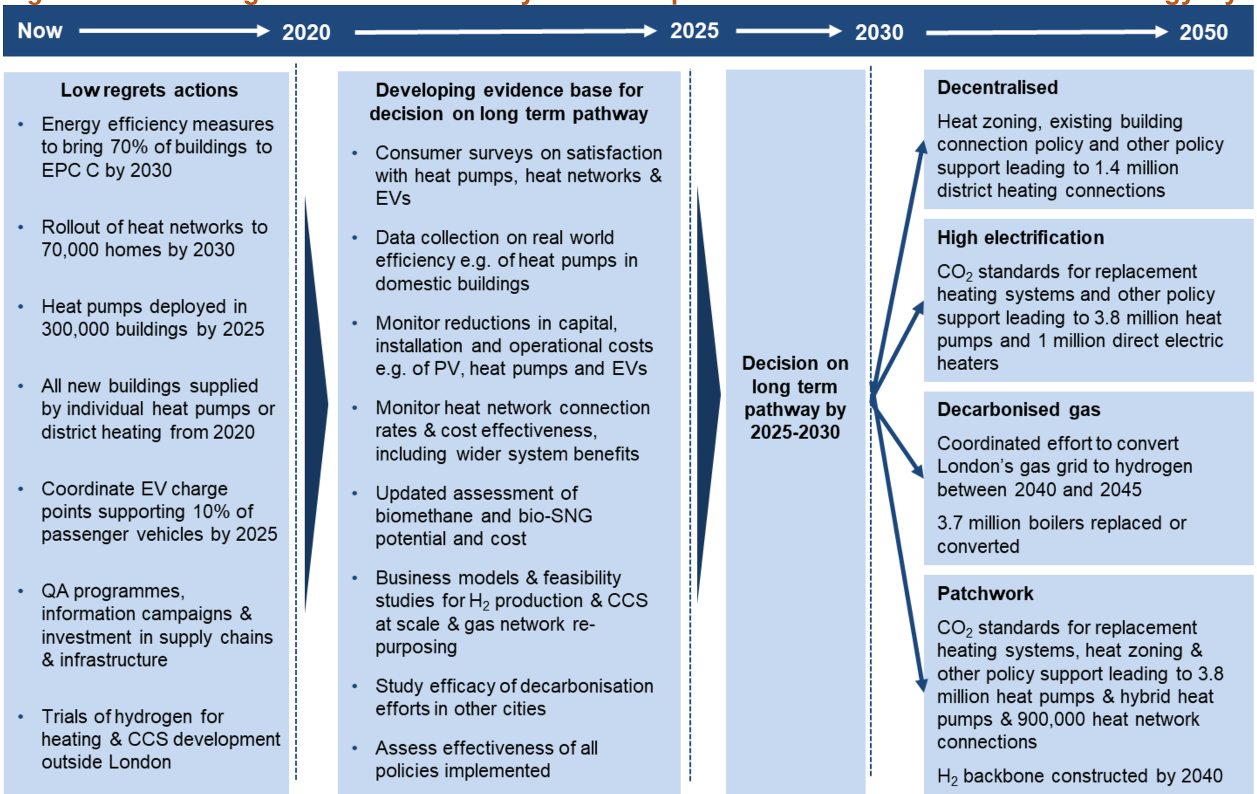
Beyond the low regrets actions, planning needs to start now in order to ensure that decisions on the longer term decarbonisation pathway can be made by the mid-2020s, when the various scenarios described below diverge more clearly. Each scenario focuses the greatest policy effort in a single area (district heating, heat pumps, or full hydrogen grid conversion) to reflect approximately equivalent levels of policy ambition. Figure 6-6 presents a timeline of the actions and decisions discussed.

In the Decentralised scenario, a heat zoning policy to drive high levels of connection to existing domestic buildings is implemented around 2025. This is a challenging policy to enact given that it is likely to impact on consumer choice, and there will be a need to ensure fairness and value for money. This scenario will also require the delivery of a large volume of associated infrastructure, which represents another key challenge.

The High electrification and Patchwork scenarios entail a similar decision in the 2020s, in this case to limit (likely through regulation) the carbon intensity of replacement heating systems in existing buildings in addition to the further strengthening of new build regulation. This, too, is an ambitious policy decision that addresses the most challenging segment – existing domestic buildings – but is required to achieve the levels of heat pump uptake needed to decarbonise the heating sector in these scenarios.

In the Decarbonised gas scenario, a national decision on the future of the gas network, and the option of large-scale use of hydrogen, is required around 2025. This will allow time for the development of hydrogen production and delivery technologies, CCS and hydrogen-using appliances; for national and local planning for the extensive infrastructure deployment entailed; and for the safeguarding strategic sites and assets as required. To enable this decision to be taken by around 2025, the necessary research and trial programmes to demonstrate feasibility should be completed in advance of this date, as there is still a large uncertainty and significant risk around this scenario. The GLA and London’s boroughs will likely have a role to play in coordinating and facilitating the switchover and protecting consumers through influence over the required network regulation.

Figure 6-6 Low regrets actions and key decision points to decarbonise London's energy system



7 Appendix

7.1 Glossary

ASHP	Air-source heat pump
BEIS	Department for Business, Energy & Industrial Strategy
BEV	Battery electric vehicle
Bio-SNG	Bio-synthetic natural gas
CCS	Carbon capture and storage (of CO_2)
CHP	Combined heat and power
CO_2	Carbon dioxide
COP	Coefficient of performance
CP	Charge point (for EV)
DH	District heating (heat networks)
DLC	Direct load control (remote electricity grid management by DNO)
DNO	Distribution network operator
DSR	Demand-side response
EHV	Extra-high voltage
EPC	Energy Performance Certificate (energy efficiency rating)
EV	Electric vehicle (PHEV, BEV or FCEV)
FCEV	Hydrogen fuel cell electric vehicle
FiT	Feed-in-tariff
GLA	Greater London Authority
Green gas	Defined in this study to include biomethane and bio-SNG
GSHP	Ground-source heat pump
H_2	Hydrogen
HGV	Heavy goods vehicle
HHP	Hybrid heat pump (refers in this study to a heat pump in combination with a gas boiler, with some form of control system to determine which one or two of these sources to dispatch at a given time)
HIU	Heat interface unit (for DH connection)
HP	Heat pump
HRS	Hydrogen refuelling station
ICE	Internal combustion engine (conventional vehicle engine)
LGV	Light goods vehicle
Low-T system	Low temperature heating system
LSOA	Lower Super Output Area
Micro-CHP	Building scale combined heat and power
Mode switch	Switch from use of private vehicles to public transport, walking and cycling
MSOA	Middle Super Output Area
MTS	Mayor's Transport Strategy
New build	Defined in this study to refer to buildings built after 2015
NO_2 NO_x	Nitrogen dioxide or nitrogen oxides emissions
PHEV	Plug-in hybrid electric vehicle
PM	Particulate matter
PV	Photovoltaic (solar panels)

RHI	Renewable heat incentive
Secondary heat	Waste heat and heat from the environment
SMR	Steam methane reforming
TCO	Total cost of ownership
TfL	Transport for London
ToU	Time-of-use tariff (electricity tariff that varies over the time of day and/or year)
TS	Thermal storage for space heating, used in addition to thermal storage for domestic hot water
WSHP	Water-source heat pump
ZEV	Zero emissions vehicle (BEV or FCEV)

7.2 Cost assumptions

Below is a summary of the cost assumptions used in the modelling for this project. For many technologies there are also low and high sensitivities to estimate the uncertainty in cost. For more detail please see the accompanying charts workbook[71], where references can also be found for the sources of these assumptions.

Building level costs

Table 7-1 Cost assumptions for building level technologies

Building technology (see cost curves)	Tech including installation Cost £	Lifetime (years)	Maintenance Cost £/year
Domestic			
Gas Boiler	£2,093	15	£126
Electric Heating	£1,145	20	£34
Low temperature heating system	£3,512	NA	NA
Heat interface unit (inc. meter)	£1,900	15	£57
Heat pump (existing building)	£7,175	20	£215
Heat pump (new building)	£5,925	20	£178
Hybrid heat pumps	£6,725	20	£202
Solar thermal	£3,704	20	£60
Hydrogen boiler	£2,393	15	£144
Additional thermal storage	£900	NA	£0
PV	£4,547	20	£21
Non-domestic			
Gas Boiler	£3,388	15	£203
Electric Heating	£2,182	20	£65
Low temperature heating system	£4,461	NA	NA
Heat interface unit	£6,894	15	£207
Heat pump (existing building)	£22,903	20	£687
Heat pump (new build)	£18,913	20	£567
Hybrid heat pumps	£21,467	20	£644
Solar thermal	£37,637	20	£610
Hydrogen boiler	£3,988	15	£239
Additional thermal storage	£1,143	NA	£0
PV	£14,517	20	£194

Table 7-2 Assumed smart system installation costs

Smart System	Domestic / Non-domestic	Cost per installation £
Smart system installation	Domestic	£302
Smart system installation	Non-domestic	£302

[71] London's Climate Action Plan work package 3, accompanying charts workbook, Element Energy 2018

Table 7-3 Cost curve assumptions

Summarised cost curves	Central								Low	High
	2015	2020	2025	2030	2035	2040	2045	2050	2050	2050
Heat pumps	100%	97%	94%	91%	88%	85%	82%	79%	70%	97%
Hybrid heat pumps	100%	97%	94%	91%	88%	85%	82%	79%	70%	97%
Solar thermal	100%	97%	94%	91%	88%	85%	82%	79%	79%	86%
PV - Capital	100%	89%	78%	77%	77%	76%	75%	74%	74%	74%
PV - Operational	100%	85%	70%	69%	68%	67%	67%	66%	66%	66%
Building elec storage	100%	40%	30%	20%	19%	18%	16%	15%	15%	40%
Network elec storage	100%	67%	53%	44%	40%	36%	33%	30%	30%	30%
Smart system	100%	67%	33%	0%	0%	0%	0%	0%	0%	100%
Home EV charger	100%	91%	82%	77%	72%	69%	67%	67%	34%	83%
Workplace EV charger	100%	90%	81%	74%	69%	66%	64%	63%	26%	82%
Public EV charger	100%	87%	75%	66%	60%	55%	53%	52%	15%	76%
Rapid EV charger	100%	88%	87%	86%	86%	86%	86%	86%	71%	93%
Hydrogen refuelling station	100%	65%	58%	50%	50%	50%	50%	50%	50%	65%

Fuel costs

Table 7-4 Assumed retail fuel prices

Summary of retail fuel price assumptions p/kWh		2015	2050	2050	2050
			Low	Central	High
Petrol		12.5	14.5	16.1	18.6
Diesel DERV		11.7	13.5	15.2	17.8
Natural gas	Industrial	2.2	2.4	3.5	4.1
	Non-domestic	2.7	3.1	4.2	4.9
	Domestic	4.9	3.9	5.0	5.7
Electricity	Industrial	9.7	11.8	12.9	13.5
	Non-domestic	10.7	13.5	14.5	15.0
	Domestic	15.9	18.1	19.1	19.4
Biomethane		8.6	5.0	8.6	12.9
Bio SNG		7.3	5.8	7.3	8.6
Hydrogen - SMR + CCS			5.8	7.6	9.3
Hydrogen - Electrolysis		15.3	12.3	15.3	17.7

Infrastructure costs

Table 7-5 Assumed electricity grid upgrade costs

Electricity grid upgrade costs		Cost £/MVA
Electricity Grid upgrades - primary substation	132 kV	£244,000
Electricity Grid upgrades - primary substation	EHV	£388,000
Electricity Grid upgrades - secondary substation	HV	£147,000
Electricity Grid upgrades - transmission	400 kV	£246,000

Table 7-6 Assumed hydrogen infrastructure costs

Hydrogen infrastructure conversion (£ m)	Low	Central	High
Gas grid repurposing cost to full hydrogen	£1,309	£2,948	£3,257
Hydrogen backbone infrastructure cost	£200	£297	£600
Industrial equipment hydrogen conversion	£10	£19	£38

Table 7-7 Assumed transport infrastructure costs

Transport infrastructure	Power kW	Total Cost (unit + installation) £	Lifetime (years)	Maintenance Cost £/year
Home charge point	7	£792	15	£0
Workplace charge point	7	£950	15	£0
Public charge point	7	£5,941	15	£270
Rapid charge point	50	£42,723	15	£270
Depot charge point (HGV, buses)	44	£42,723	15	£270
Hydrogen refuelling station	500kg/day	£1,584,158	20	NA

Table 7-8 Assumed heat network energy centre technology costs

Heat network energy generation Energy centre technology	Plant CAPEX £/kW$_{th}$			OPEX £ / kW$_{th}$ / yr		
	Low	Central	High	Low	Central	High
Large power and industrial (WSHP)	£725	£768	£779	£3.6	£3.8	£3.9
CHP	£722	£722	£722	£60.8	£60.8	£60.8
Transformers (WSHP)	£725	£768	£779	£3.6	£3.8	£3.9
FC CHP	£722	£1,083	£1,444	£50.6	£75.9	£101.3
Commercial heat rejection (WSHP)	£725	£768	£779	£5.2	£5.5	£5.6
Building Heat Rejection HVAC	£725	£768	£779	£3.6	£3.8	£3.9
Rivers (WSHP)	£1,036	£1,097	£1,113	£5.2	£5.5	£5.6
Sewer heat mining (WSHP)	£1,243	£1,317	£1,335	£6.2	£6.6	£6.7
Air Source Heat Pumps	£583	£617	£626	£3.0	£3.2	£3.3
Ground Source Heat Pump	£1,475	£768	£1,584	£2.2	£2.4	£2.4
Peak demand gas boilers	£40	£40	£40	£2.1	£2.1	£2.1
Peak demand hydrogen boilers	£40	£60	£80	£2.1	£3.2	£4.3
Peak demand ASHP	£583	£617	£626	£3.0	£3.2	£3.3
Peak demand GSHP	£1,475	£768	£1,584	£2.2	£2.4	£2.4

Table 7-9 Assumed heat network thermal storage costs

Heat network thermal storage	CAPEX £/MWh$_{th}$ storage
Low	£36,000
Central	£41,000
High	£46,000

Table 7-10 Assumed Heat network distribution pipework costs

Heat network distribution		Capital cost of distribution pipework £/m of trench		
		Low	Central	High
Secondary pipework	Domestic - exc. flats	£535	£559	£583
	Domestic - flats	£579	£605	£631
	Non-domestic	£535	£559	£583
Primary pipework		£1,346	£1,406	£1,466

7.3 Exergy background

For many energy sources, such as electrical energy or natural gas, the amount of exergy is almost equal to the amount of energy, as they are 'high quality' forms of energy. The concept of exergy is particularly useful when comparing heating technologies, as the exergy of heat varies with its temperature. The exergy contained within a source of heat energy Q (with constant temperature T) is given by:

$$Exergy = Q(1 - \frac{T\mathrm{ref}}{T})$$

Where T_{ref}, is a chosen reference temperature, in Kelvin, which is often the ambient temperature. For this analysis, T_{ref} is the temperature of the environment, hence the environment is defined to have zero exergy. In reality, this represents the fact that it is difficult to recover energy from the environment and transform it into a higher quality form.

It should be noted that the results of energy and exergy analysis depend on where the system boundaries are drawn; we have chosen to draw our boundary at the electricity grid, so that electricity is defined as a primary energy source and the electricity production methods are not included in the analysis. It should be noted that hydrogen is considered an intermediate energy source in this analysis; primary energy for hydrogen production is included here in the electricity or natural gas consumption, for electrolysis or SMR production methods respectively. The energy and exergy losses are therefore included for the production of hydrogen, where they are excluded for the production of electricity.