2050 Energy Scenarios

The UK Gas Networks role in a 2050 whole energy system

July 2016

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This report contains forward looking scenarios for the energy system in Great Britain in 2050. All statements other than statements of historical fact are, or may be deemed to be, forward looking scenarios. Note that forward looking scenarios are scenarios of future developments that are based on current expectations and assumptions. There are a number of factors (including risks and uncertainties) that could cause future developments to differ materially from those stated in, implied by or inferred from the forward looking scenarios contained in this document.

Kiwa Gastec have provided technical knowledge and expertise that have informed the analysis and conclusions of this report. All analysis and conclusions in this report have been agreed between KPMG and Kiwa Gastec.

The data in the report and its appendices have been generated under a range of input assumptions which have been formed as part of a scenario development process. The data should not be regarded as projections or predictions nor should reliance be placed on the data set out.

Contents

1 Executive Summary

An Essential Service

Gas is essential to today's society. It provides an instant and efficient heat energy source for families and businesses throughout Britain, and for electricity generation and industry. The UK gas industry has a 200 year history which has seen a switch to natural gas, the development of national and gas transmission and distribution networks, industry privatisation, and international gas markets enabling gas to be supplied from around the world. But the future of gas depends on finding solutions to the challenges ahead.

The Driver of Change

The biggest driver of change across the energy sector is the reduction of carbon emissions across power, heat and transport. The Climate Change Act 2008 requires that by 2050 Greenhouse Gas Emissions, the majority of which is carbon dioxide (CO2), will be reduced to 20% of 1990 levels. Decarbonisation of power is already well advanced but heat and transport are lagging significantly behind. Gas, as the major source of heat, will need to be decarbonised in some way.

Our task

Energy Networks Association (ENA) Gas Futures Group asked us to prepare a report on the cost effective and practical future alternatives for the decarbonisation of heat by 2050 with a particular focus on the future role of gas and its subsequent impact on the gas networks.

The future decarbonisation challenge

Energy used for heat accounts (in terms of final consumption) for approximately 45% of our total energy needs, and is critical for families to heat their homes on winter days. Decarbonising heat while still meeting peak winter heating demands is recognised as a big, perhaps the biggest, challenge for the industry.

The way heat has been delivered in the UK has not fundamentally changed for decades and huge investments have been made in gas infrastructure assets ranging from import terminals to networks through to the appliances in our homes. Changing how heat is delivered, whichever way is chosen, will be a major economic and practical challenge affecting families and businesses everywhere.

Any plan to decarbonise will need to address power and transport, alongside heat. Our report has also looked at potential decarbonisation of power and transport, as part of a whole energy system approach.

Our report

In this report we explore ways that the heat sector can be decarbonised, by looking at four possible future scenarios set in 2050. These stylised scenarios present illustrative snapshots of alternative energy solutions. The scenarios do not present a detailed roadmap – indeed the future may include some elements from each. We have analysed the advantages, disadvantages, and costs of each scenario.

All our scenarios meet the 2050 Carbon emissions targets. In this report we have concentrated on reductions to CO2 emissions and we have not considered other greenhouse gases.

1.1 Our scenarios

Our scenarios show four potential ways that energy demand, particularly heat demand could be met in 2050.

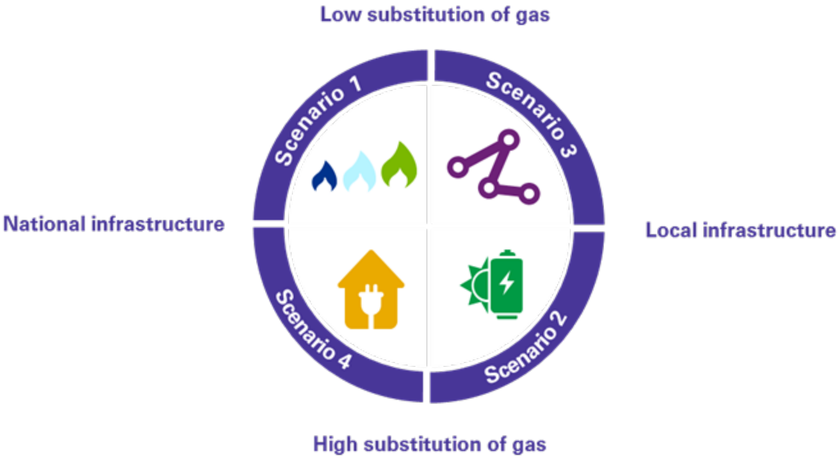
We use a common demand assumption across all four scenarios (adapted from National Grid's Future Energy Scenarios 2015 'Gone Green' scenario) to ensure we compare like with like. We also use common assumptions for decarbonising power and for continued natural gas (and transmission) use by bulk off-takers.

1 Evolution of Gas networks

- Gas remains the main heating fuel for the majority of customers.
- Heat is partially decarbonised. The majority of customers convert to Hydrogen gas, derived from natural gas with CO2 permanently stored (sequestered) under the continental shelf.
- Transport is mostly decarbonised.
- Gas distribution networks are mostly used for hydrogen gas across the country.

3 Diversified energy sources

- A mixture of different technologies is used in different areas of the country.
- Heat is partially decarbonised with a mixture of biomass sourced heat networks, gas and electric heating.
- Transport is partially decarbonised.
- Gas distribution networks only used in half of the country.



4 Electric Future

Switch to electric heating systems.

- Heat is decarbonised with assumption that power generation is completely decarbonised by 2050.
- Majority of Transport is decarbonised.
- Gas distribution networks not used.

2 Prosumer

Self-generating heating and energy solutions develop, but only provide minority of energy, the rest use electric heating.

- Heat is decarbonised with a mixture of self-generating heat and storage, and electric heating.
- Majority of Transport is decarbonised.
- Gas distribution networks not used.

1.2 Our analysis

Our analysis is summarised below, and highlights the key advantages and disadvantages of each scenario. We provide an assessment of practical obstacles and of the incremental costs required for each solution.

	Evolution of Gas	Prosumer	Diversified energy	Electric Future
Practical obstacles	Low/Medium	Very high	Medium/High	High
Incremental cost	£104-122bn	£251-289bn	£156-188bn	£274-318bn
Incremental cost per consumer up to 2050	£4,500-5,000	£11,000-12,500	£6,800-8,000	£12,000-14,000

1 Evolution of Gas networks

The use of alternative gases such as hydrogen and biogas is technically feasible today. Much of the existing gas infrastructure can be used, thereby limiting the inconvenience of change for gas customers and society overall. The same fuel can supply both heat and transport. But conversion at scale will be logistically challenging although it was carried out in the 1960s and 1970s.

3 Diversified energy sources

This will require local authorities to take a lead in local solutions to deliver heat to homes and businesses. Diverse approaches will present delivery challenges in terms of design, planning, customer participation, obtaining funding, and the ability to implement change.

4 Electric Future

This is technically possible but significant investment will be needed to meet peak heat demand. This will require new equipment in the home, reinforcement of electricity networks and new generation, including back up capacity for some renewable capacity at winter heating peaks. Conversion will face design, planning, customer acceptance, and funding challenges.

2 Prosumer

In this scenario some consumers generate their own energy. The technical difficulties of inter-seasonal energy storage means that most customers will be unable to generate sufficient heating energy, so we have only assumed that a minority of customers are fully prosumer. The rest largely use grid electricity leading to increased demand from electricity networks and generation.

	Evolution of Gas	Prosumer	Diversified energy	Electric Future
Technical Feasibility	— Gas networks already meet peak heat demand — Hydrogen well understood but conversion yet to be tested at scale — No additional storage needed to cover peak	— Difficulty in meeting peak heat demand — Large amount of inter-seasonal heat storage a major barrier — Large electricity back up capacity needed to cover renewable intermittency — Prosumer technologies not yet tested at scale	— Meeting peak demand is achievable, with additional investment in some areas — Uses available local resources — Some storage needed in some scenarios	— Major difficulty in meeting peak heat demand — Large amount of inter-seasonal electricity storage a major barrier — Large electricity back up capacity needed to cover renewable intermittency — Overall technology proven and well understood
Customer acceptance	— Functionality and space requirements the same as today — Customers may be reluctant to change	— Very challenging to get consumers to accept different functionality — Space not available for many customers	— Regional differences in functionality — Restrictions on available space and access for installation — Customers may be reluctant to change	— Heat pumps efficient but challenging where space is limited — Challenging to get consumers to accept different functionality
Society acceptance	— Limited disruption from new gas infrastructure — Acceptance of new CO2 disposal facilities required	— New electricity infrastructure will cause significant disruption — Domestic retrofitting will be a considerable challenge	— Considerable disruption in urban areas from heat network installation — Regional systems untested in UK	— Significant urban disruption as electricity infrastructure is reinforced — Domestic retrofitting will be a considerable challenge

1.3 Key conclusions

Our scenarios are just four examples of what could happen. While our analysis shows advantages for the 'Evolution of Gas' scenario, in reality the future of heat in 2050 is likely to be somewhere between all four scenarios.

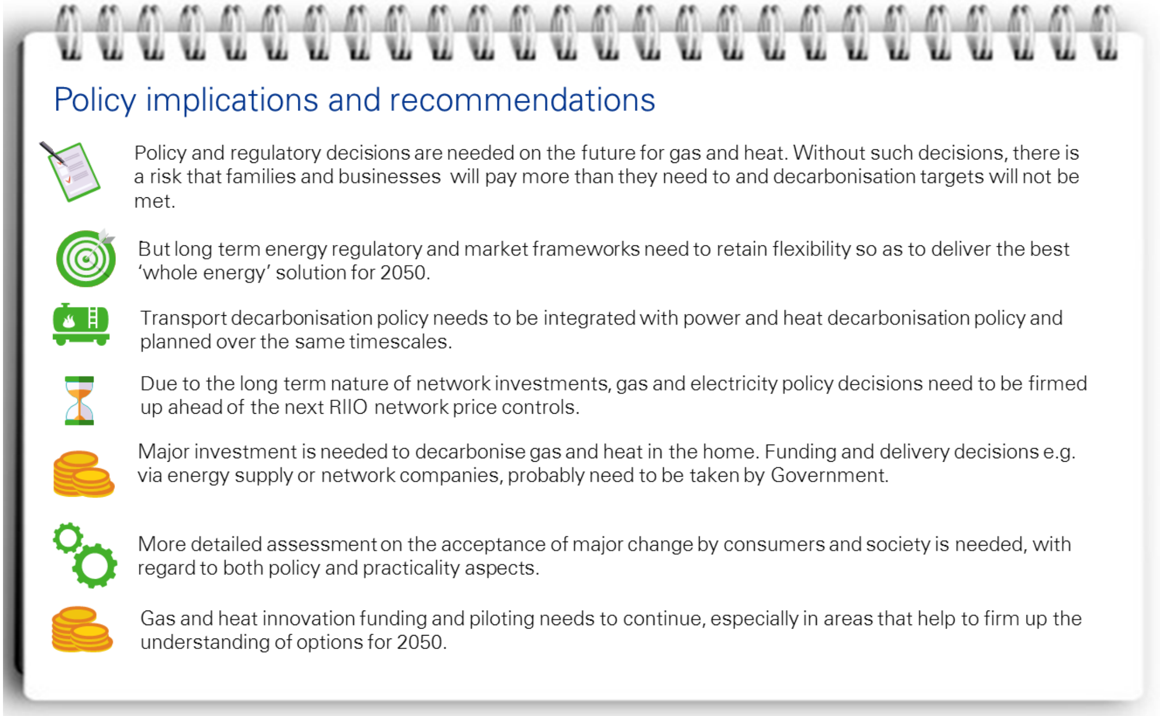
However, looking at the feasibility of alternative futures does present some key conclusions:

Cost of change

- Large investment will be needed to decarbonise the heat sector which ever option is chosen. Replacing winter peak gas heating demand is the most significant cost driver.
- The most critical investments are needed in homes and businesses to convert to new energy sources. Funding for this, and incentives to change, will need to be identified.
- Continuing to use the gas network offers significant savings versus alternative heating sources.
- Transport decarbonisation needs to take place alongside heat & power to optimise whole system costs.

Practicality of change

- Customers value the convenience and reliability of the current heat system, and may resent change.
- Customers will face practical issues such as space and affordability that will restrict their ability to change.
- Major changes to energy systems will face multiple planning, access, and installation barriers.
- Being able to back up intermittent renewable generation will be a challenge for all electric scenarios.
- Inter-seasonal heat storage is a major technical challenge and we expect this to be limited in practice.



Policy implications and recommendations

- Policy and regulatory decisions are needed on the future for gas and heat. Without such decisions, there is a risk that families and businesses will pay more than they need to and decarbonisation targets will not be met.
- But long term energy regulatory and market frameworks need to retain flexibility so as to deliver the best 'whole energy' solution for 2050.
- Transport decarbonisation policy needs to be integrated with power and heat decarbonisation policy and planned over the same timescales.
- Due to the long term nature of network investments, gas and electricity policy decisions need to be firmed up ahead of the next RIIO network price controls.
- Major investment is needed to decarbonise gas and heat in the home. Funding and delivery decisions e.g. via energy supply or network companies, probably need to be taken by Government.
- More detailed assessment on the acceptance of major change by consumers and society is needed, with regard to both policy and practicality aspects.
- Gas and heat innovation funding and piloting needs to continue, especially in areas that help to firm up the understanding of options for 2050.

2 Introduction

The UK gas and electricity industry plays a critical role in modern society and in the economic performance of the nation. It provides an essential service with high standards of reliability and service. While the gas industry has a 200 year history, it is today facing one of its biggest challenges. Responding to climate change has already seen dramatic changes over the last few years in the power sector, and both heat and transport will face a similar challenge.

We are currently at a major crossroads where the future of energy delivery in the long term is less certain that it has been for decades. The Climate Change Act 2008 and other carbon emissions targets necessitate an evolution in the way energy is delivered and a number of different technologies and/or fuels offer potential solutions.

ENA Gas Futures Group asked KPMG and Kiwa Gastec to prepare a report on future alternative 2050 scenarios for energy decarbonisation with a particular focus on the future of gas, the practicalities and costs of change, and the subsequent impact on the networks. This is in the context of the target set out in the Climate Change Act for the UK to reduce its carbon emissions by at least 80% from 1990 levels by 2050[1]. Our report examines what role gas and gas networks could play within the wider energy system in helping to meet this reduction.

The change required by 2050 will be profound and will impact all parts of the industry significantly. In looking at the industry landscape for 2050, we have used a scenario approach which paints some potentially dramatic changes in order to assist thinking with the key policy, economic and regulatory drivers.

In considering how decarbonisation targets for 2050 might be realised, we forecast 2050 energy consumption for industry, commercial and domestic use, and for transport. We then produced four diverse scenarios that varied the mix of energy sources to meet both the forecast demand and emission reduction targets. These scenarios ranged from future decarbonisation of gas to replacement of gas by electricity. We then compared the potential benefits and challenges of each scenario and assessed the potential incremental costs of implementing each scenario. Finally, we have set out our conclusions and suggested some policy options for further consideration.

2.1 Decarbonisation targets

Statutory decarbonisation targets are set in UK domestic legislation for 2050. We assume that the 2008 Climate Change Act and the carbon budgets remain in place, although this may potentially change following the recent EU referendum outcome. The recent climate change summit in Paris reinforced international ambitions for carbon reduction. International progress on decarbonisation is limited to date and there is a long way to go to meet the 2050 target. While the UK is on track for 2020, targets for heat and transport are already well behind target.

The 2050 emissions target is to reduce Greenhouse Gas (GHG) emissions to 20% of their 1990 levels. Our report only considers reduction of CO2 emissions, which form the bulk of GHG emissions. We have assumed that other measures are taken to reduce other greenhouse gases. According to the Department of Energy and Climate Change (DECC)[2] total CO2 emissions for the UK were 596 MtCO2e in 1990 therefore to meet the target UK emissions can be no more than 119 MtCO2e. As our report looks at the system in Great Britain we have not considered Northern Ireland's emissions. Northern Ireland accounts for 4% of emissions. We have therefore reduced the emissions target by 4%. This gives us a maximum of 115 MtCO2e in 1990.

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[1] Carbon Budgets and Targets, Committee on Climate Change.

[2] Updated Energy Emissions Projections 2015, DECC

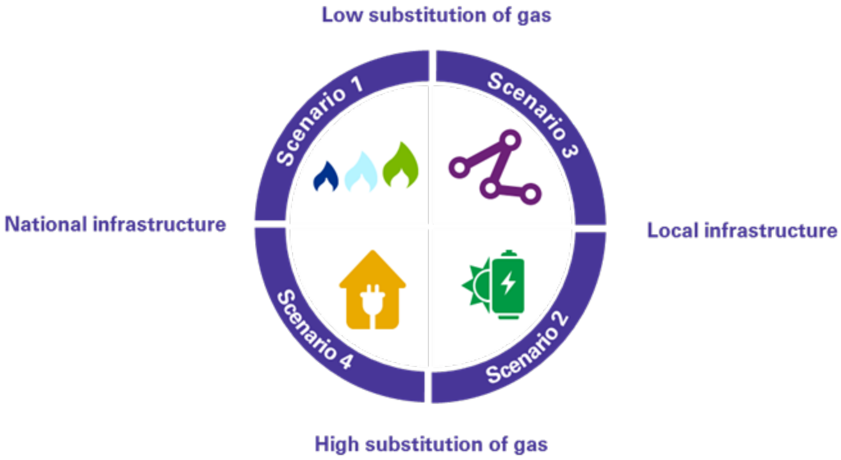
2.2 Choosing scenarios

In order to develop a view of the future, KPMG and Kiwa have looked at four different ways that the energy system could develop, giving us four 2050 energy scenarios which we have explored further in this report. To develop our scenarios we have looked at two major variables:

- How much will gas continue to be used as a final source for consumers?
- Whether decisions about future energy use be taken locally or nationally (or both)?

These variables gives us a matrix with four potential directions the energy system could develop.

Figure 2.1: The four scenarios



These scenarios are ‘snapshots’ of what an energy system in 2050 may look like. They are not meant to be accurate predictions, rather they are meant to show a wide range of potential options. We recognise that the energy system is unlikely to develop according to one particular scenario; rather a mixture of potential scenarios is likely to emerge.

Our study is not a comprehensive ‘bottom-up’ study of costs but rather a top down high level approach, using existing data and estimations particularly from DECC[3] and National Grid.[4]

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[3] Updated energy and emissions projections, 2015 DECC.

[44] Future Energy Scenarios, National Grid

2.3 Developing the scenarios

Common assumptions

In order to compare scenarios, we have made certain underlying common assumptions, and then identified certain key variables that are adjusted for each scenario. In particular:

- We have based our scenarios on the delivery of total UK final energy consumption, covering domestic, industry, transport, and other final customers.
- Out of final energy consumption, each scenario varies the energy supply assumptions for the most significant variable components. These are residential and commercial power and heat, and transport (road and rail).
- We have used common demand assumptions for each scenario.
- Under all scenarios, the 2050 electricity generation mix is assumed to comprise natural gas, renewables and nuclear.
- Under all scenarios, we have assumed the National Transmission System transports natural gas for power generation and industry.
- We have assumed each scenario meets the UK's 2050 carbon emissions target.

Key variables in each scenario

For each scenario, this report considers the key influences affecting the development of energy systems through to 2050 and identifies different ways that this demand could be met while meeting the 2050 targets. In our report we have looked at:

- **The options for which fuels will be used to provide residential and commercial heat demand.** We have explored the different options including a greater role for electricity, a continuing role for natural gas (methane) or alternative fuels such as hydrogen.
- **The implications for our two major energy networks, the gas and electricity grids**. Looking at how we will have enough capacity in our networks to deliver energy at peak times, i.e. 7pm on a cold winter's day.
- **The cost implications of change at a property level**. How converting the appliances in individual homes and businesses is a real driver of overall costs.
- **The impact of transport (road & rail) on decarbonisation**. Transport[5] is the other major energy sector accounting for approximately 40% of energy demand. In order to meet targets there will have to be substantial decarbonisation of transport as well as heat. While this is not the main focus of our study and we have not sought to cost this, each scenario looks at different ways that transport could be decarbonised in conjunction with the energy sector.

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[5] We exclude domestic aviation and shipping. International aviation and shipping is not included in UK emissions targets.

3 Context for the scenarios

3.1 The energy trilemma

The energy trilemma is a challenge now, but will become more difficult by 2050 as interventions (with associated costs) will be needed to achieve decarbonisation policy aims.

Security of supply

The need to ensure we have enough energy to sustain our economy is a vitally important consideration for policy makers. Although the traditional link between economic growth and energy demand appears to be changing in recent years[6] as increased energy efficiency takes hold, there will still be a critical need to maintain the security of energy supplies. Gas remains a readily available source of energy for the GB market and this looks set to continue to be the case in the longer term.

Renewable energy sources, particular solar and wind are intermittent generators which require flexible generating capacity, storage or demand response to smooth this intermittency. Gas has a proven ability to meet peak energy demands, and can play an important role in the future.

Decarbonisation of heat

The need to reduce carbon emissions are a key part of the energy trilemma while legislation may change in the future. The Climate Change Act 2008 set the framework for the UK to transition to a low-carbon economy requiring a reduction of 40% in CO2 emissions compared to 1990 with a long-term objective of 80% by 2050.

Table 3.1: 2050 GHG emissions[7]

All units MtCO2e	1990 Emissions level	2050 target emissions	Minimum Reduction needed
CO2 Emissions	596	119	- 477
GHG emissions[8]	807	161	- 646

More recently, and concurrently with the worldwide Annual Climate Change Conference of Parties (COP21) in Paris, the UK's fifth carbon budget set the limit on emissions of 1,765 MtCO2 (including emission from international shipping[9]) in the period 2028-32. This target would limit annual emissions to an average 57% below 1990 levels.

Delivering energy efficiently

Since the discovery of North Sea gas and the construction of the National Grid in the 1960's and 70's natural gas (methane) has met the bulk of the country's energy need. The current GB energy network was designed and built in the 20th century to deliver reliable and efficient energy to homes and businesses throughout the UK. The infrastructure has grown up around this, from production to networks, through to the appliances in individual properties. This infrastructure represents a massive investment by UK Plc and energy customers.

As well as lower carbon emissions, another important factor is fuel transportation and conversion efficiency. Generally speaking it is far more efficient to use a fuel directly at the point of use rather than convert to other energy forms prior to transportation.

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[6] DECC data.

[7] 1990 Emission level is taken from Table 1, Final UK greenhouse gas emissions national statistics 1990-2013 Excel data tables. The 2050 target emission is based on the 80% reduction target.

[8] Green House Gas emission (GHG) are mostly carbon but also include other gases harmful to the environment.

[9] The Fifth Carbon Budget, Committee on Climate Change.

A significant advantage of gas is it can be used directly in homes and businesses as a heating fuel with a relatively small amount of energy losses from transportation.

By contrast using electricity as a heating source requires the conversion of a fuel into electricity and then losses as the electricity is transported through the grid. Using electricity for heating in homes and businesses may also result in losses and be less efficient.

The more efficient we can be with our energy, the lower the costs to customers and the lower the security of supply risk.

3.2 Energy demand

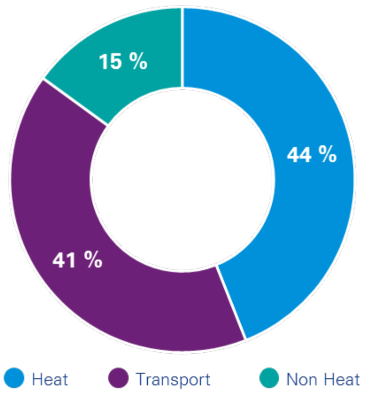
Our report focuses on the use of energy demand by domestic and commercial customers. This demand is split three ways:

- Power (Non-heat) - energy for non-heating electric appliances - lighting, consumers goods (TVs, washing machines etc.)
- Heat - energy for space heating, hot water and cooking[10]
- Transport - energy needed to move around by road (car or bus) or rail[11]

In the UK, 44% of the energy we consume is used for heating of one sort or another. And of the total of 906 TWh of natural gas consumed in the UK in 2011, 52% was used to provide heat for buildings and industry. This compares to the 34% burned in power stations to make electricity[12].

Although electric hybrid vehicles have gained in popularity and a large proportion of rail transport is electrified, the majority of energy for transport is provided by fossil fuels - petrol and diesel.

Figure 3.1: GHG emissions



Source: DECC

The gas network is the source of heat for approximately 23 million properties in GB. 84% of homes are connected to the gas network[13], the remainder use either electrical heating, are connected to heat networks (approximately 2%), LPG or oil.

Overall, approximately two-thirds of residential and commercial energy consumption is met by natural gas (methane). Due to the seasonal nature of heat demand at peak times during the winter this proportion can be even higher.

The most significant challenge for decarbonisation of heat will be to meet this winter peak heating demand by alternative means.

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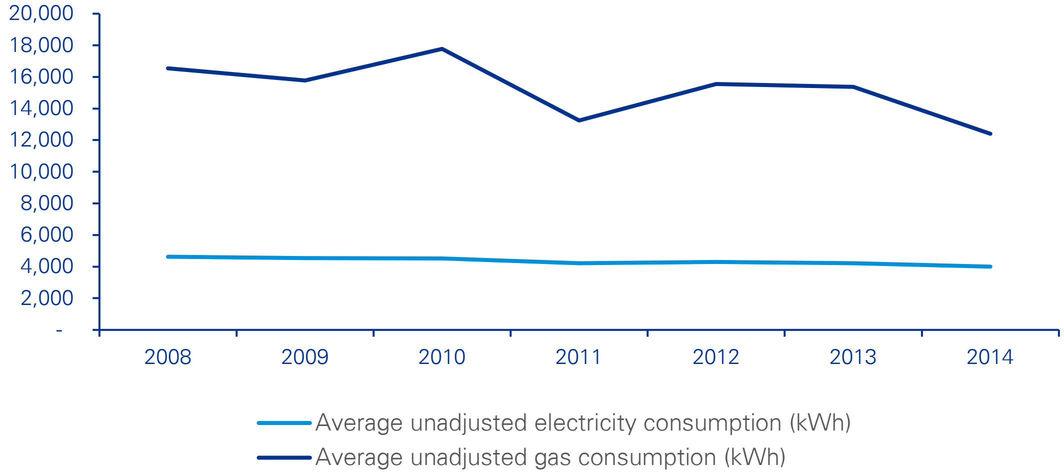
[10] For the purposes of our study we have focused on residential and commercial heat demand rather than the specific heat needs of industrial users.

[11] Aviation and shipping is out of scope of this study.

[12] The Future of Heating meeting the challenge 2013, DECC.

[13] The future of the gas network, UCL.

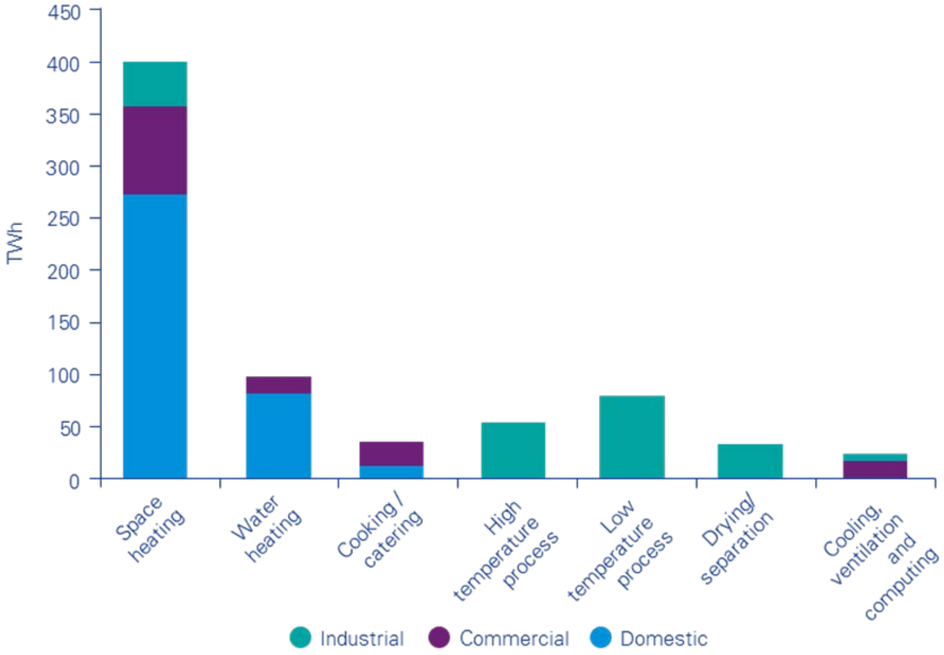
Figure 3.2: Peak energy demand – Electricity and gas



Source: DECC, ECUK 2015 Tables 3.07

3.3 Carbon emissions

Figure 3.3: Energy consumption for heating by sub-sector and end-use in TWh (2011)



Source: DECC

Energy demand in the home and the office

The majority of households in GB use gas for space heating, water heating and cooking/catering (though gas ovens and hobs are declining).

Table 3.2: Domestic appliances in GB

Domestic appliances	Gas	Electric	Other
Cooking/catering	56%	44%	-
Lights & appliances	-	100%	-
Space heating	77%	7%	15%
Water heating	80%	9%	12%

Source: Energy consumption in the UK, DECC 2015

The millions of gas appliances in homes up and down the country together represent a significant sunk cost. Any change in energy sources that will necessitate a change in appliances will result in significant capital costs.

Customer acceptance

A study by Wales and West Utilities (WWU) on consumer willingness to pay for alternative heating sources[14] highlights that around 90% of domestic consumers would only be willing to change their existing heating provision if:

- Significant financial benefits would be accrued;
- They have funding available; and
- The system is coming close to the end of its cost effective lifecycle and/or actually fails.

In other words, if a customer's current heating system is operating well, the customer would not be willing to change his/her heating system and spend money unnecessarily. Alternatively, if a customer is offered a financial incentive to change, they would be more willing to do so.

A key consideration therefore is the ability and propensity to change compared to what we have today. If customers either cannot afford or do not want new appliances then this could prove a significant hurdle to overcome.

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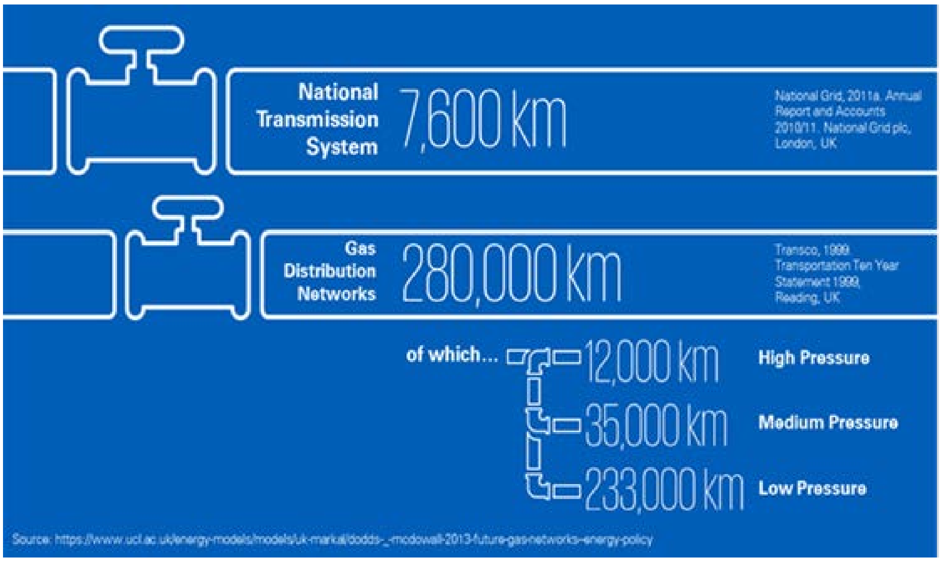
[14] Wales and West Utilities and Business Navigators Ltd (August 2015).

3.4 The gas networks today

Today, the national gas transmission system operates over a total length of 7,600 k m while the six main gas distribution networks (GDNs) operate over 280,000 km of high, medium and low pressure pipes.

The gas distribution system has been highly regarded for its reliability and availability to customers. Reliability of the network is very high (99.99%).[15]



Source: UCL, 2013 Future Gas Networks energy policy.

The gas transmission network is also interconnected to Europe, with pipelines connecting the UK to Norway, Belgium, the Netherlands and Ireland. There are also Liquefied Natural Gas (LNG) terminals at Grain and Milford Haven.

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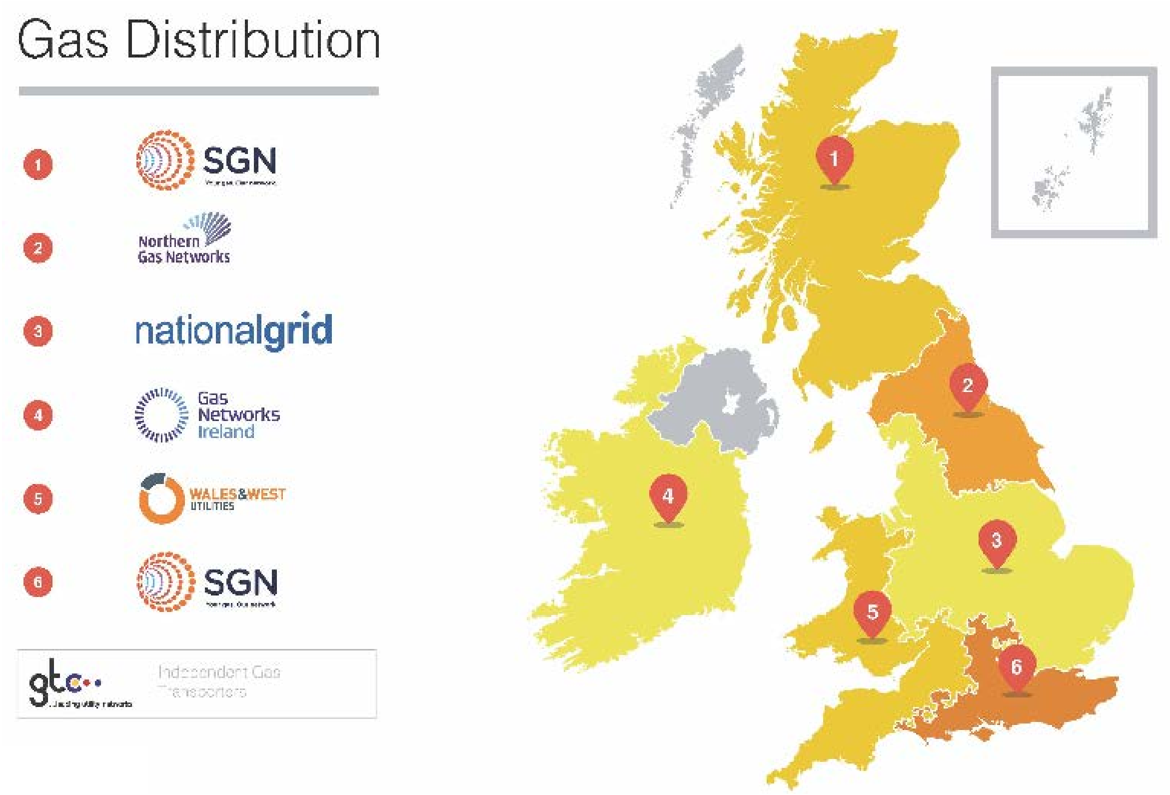
[15] National Grid website.

The Gas distribution networks

Figure 3.4: Map of the gas distribution networks



Source: ENA.

Much investment continues to be made to the gas networks. A recent report by DECC (2015) states that £3.8bn were invested in the GB gas networks (Totex) between 2010 to 2014 and this supported circa 11,500 jobs[16]. There is continued investment in the networks. The Iron Mains Risk Reduction Programme (IMRRP) represents a major investment in the network to replace old infrastructure, the new pipes being put in place as part of this programme will last for decades.

The institutional and regulatory frameworks have evolved over time from state ownership to privatisation and to one where decisions to meet decarbonisation targets are made by government within a market structure. Network regulation also has evolved from RPI-X to RIIO, where network output performance is incentivised rather than only targeting efficiency savings. Gas Distribution and Gas and Electricity Transmission companies are regulated under RIIO-GD1 and RIIO-T1 regimes[17] respectively.

Figure 3.5: The RIIO Regulatory model

Revenue = **Incentives** + **Innovation** + **Outputs**

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[16] Delivering UK Energy Investment: Networks, DECC.

[17] Gas Distribution RIIO price Control (RIIO-GD1) started in April 2013.

3.5 Encouraging Innovation

Innovation is an important part of the price control regime. Since the implementation of RIIO, a number of innovation projects have explored different technologies, sources of gas, commercial arrangements and innovative ways networks can be maintained. In the current state of uncertainty, these innovation projects are invaluable sources of information that can help us to decide what the future may hold. We have drawn on some of these innovation projects in this report.

The key projects on the future of gas that have informed this report include:

‘H21 Leeds City Gate’

NGN are leading a study looking at the challenges, benefits, risks and opportunities of converting a major UK city, Leeds, to a hydrogen network using the existing gas network. This study shows how Hydrogen can be produced from Natural Gas using steam methane reformer technology. This is the method of producing Hydrogen that we have considered in our scenarios.

Opening up the Gas Market and Real Time Energy Networks

SGN have conducted two projects that have looked at changing the way that the gas network works. The ‘Opening up the Gas market project’ demonstrated how the current UK gas specifications, (GSMR[18]) could be extended to allow up to 90% more LNG gas to enter the network without the need for ballasting or enrichment. The project successfully demonstrated this in Oban, a small Scottish town not connected to the main network.

The ‘Real Time networks’ is a recent project that builds on the opening up the gas market project by seeking to demonstrate the gas network could manage the introduction of a range of different gas (methane) sources nationally and gather more information about how customers actually use their energy. The aim is show how the gas network can become more flexible and responsive to customers’ needs.

Bridgend Future Modelling and Cornwall Energy Island

WWU have had two projects which have looked at the feasibility, and roll-out of alternative heating technologies. The ‘Bridgend Future Modelling’ project (over three phases) looked at the roll-out of heat pumps (Ground source and air source) and heat networks in areas of Bridgend in South Wales. This included gathering evidence on costs, customer’s willingness to pay for these alternative technologies, and the policy changes that would be needed to aid rollout.

The ‘Cornwall Energy Island’ is a current project which is examining how peak energy demand could potentially be met by other energy sources. This includes the challenges in current proposals for using alternative energy sources, for example, the capability to store energy to meet seasonal peak demands.

Commercial SNG Demonstration Plant

National Grid are conducting two projects that are looking at the technical and economic feasibility of thermal gasification of waste to renewable gas (bio-substitute natural gas or BioSNG), through constructing a pilot and then a demonstration plant to take an existing stream of syngas and upgrading it to GSMR quality gas. This Bio-SNG will be fed into the gas network as bio-methane and utilised in CNG vehicles.

All information on the Gas network innovation projects can be found on ENA’s smarter networks portal.

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[18] Gas Safety (Management) Regulations.

3.6 Future Technologies and Fuels

There are a number of different ways of transporting energy and generating heat. With the myriad of options available, it is uncertain which one represent the best way to decarbonise. In our scenarios we consider a range of different fuels and technologies as highlighted below.

Table 3.3: Summary of fuels and technology considered

Technology	Description	Carbon emissions	Current Status
Biomethane	Methane produced by processing Biogas or Bio SNG. It shares similar properties to natural gas and can therefore be injected into the gas network and used by existing gas appliances.	Still carbon emitting but at a significantly lower value than natural gas.	Currently a small number of connections with many more planned. Total capacity limited by supply of truly biological renewable carbon atoms.
Hydrogen	Hydrogen is a basic element that is highly reactive. It can be used as a fuel like methane but appliances will need to be converted. Hydrogen can be transported using the existing gas distribution network. This will be easier where the iron mains are/will be replaced with plastic.	None at point of use, only by-product is water. However its production can produce emissions, if made from fossil fuel, but not if from renewables.	Not currently used as a heating fuel. Northern Gas Networks 'H21 Leeds City gate' Network innovation project is examining creating a hydrogen network in Leeds using the steam methane reformer process which removes 90% of CO2.
Shale gas	Methane that is trapped within shale rock. Previously very difficult/impossible to extract, the progress made on extraction methods in recent decade has allowed access large volumes at commercial cost (especially in the USA).	Similar to natural gas currently sourced therefore use of shale will not result in any carbon saving.	First planning permission for shale gas extraction in the UK was recently granted[19]. Shale gas has revolutionised the US market turning it from a net importer to a net exporter. But remains controversial with local residents and the environmental lobby.
District Heat Networks	A network hot water pipes supplying a number of buildings from central sources. This source could be industrial waste heat, Biomass plants or a conventional gas or electric boiler.	This will depend on the source of the heat. No/low emissions for some sources.	Heat networks currently provide around 2% of the heat demand from buildings in the UK. They are most common and effective high-density areas, but not used for modern low energy demand properties.
Biomass	Generating heating energy through range of bio fuels including wood, animal, food or industrial waste or high energy crops such as maize.	Burning Biomass still produces CO2 but at lower levels than other fuels. The carbon emissions from some biomass can be contentious.	A proven technology but limited roll-out thus far.

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[19] North Yorkshire council gave permission for a 'fracking' site in May 2016

Technology	Description	Carbon emissions	Current Status
Heat pumps	Electric powered heat pumps absorb heat from the outside air (air sourced) or ground (ground sourced). This heat is used for space or hot water heating.	Depends on the source of the electricity. The heat they extract from the air or ground is natural and renewable.	A proven technology but limited roll-out thus far.
Prosumer Heating	Customers with the ability to generate and store their own heating energy via a number of different technologies without need to take energy from the grid.	Yes, prosumer technologies use solar powered heat pumps and solar air collectors.	Solar technologies becoming more widespread but a fully 'prosumer heating' property still at experimental stage. These technologies all inherently require space, ideally within the property. Connections to electricity and gas networks may still be needed as 'back-up'.

3.7 Transport

In our study we have assumed that there is no decarbonising of other sectors of the economy such as agriculture, refineries etc. Therefore aside from heat, transport is the other key sector in the whole energy system where decarbonisation needs to be addressed. We have based our transport assumptions on analysis performed by the UK Energy Research Council (UKERC).[20]

Decarbonisation of road and rail has begun, mainly through electric trains and cars, but progress remains slow. Petrol (and diesel) still provide the vast bulk of our transport horsepower. However, decarbonisation of road and rail transport potentially has advantages that could make it easier than decarbonising heat, such as:

- New solutions are more energy efficient - the energy conversion rate of both electric and hydrogen vehicles is a lot higher than the old fuels (petrol and diesel). This is not the case for some of the proposed solutions for heating.
- They have a short asset cycle – vehicles are generally replaced every 4-8 years (although this can be longer for larger commercial vehicles and trains have an asset life closer to 30 years). Therefore older vehicles can simply be replaced by new technology vehicles. Assuming economies of scale can be reached, these green vehicles need not cost any more. By contrast housing has a long asset life. Although some new housing is built, it will not go anywhere near replacing the existing housing stock by 2050. This results in costly retro-fitting for any changes in fuels.

Clearly decarbonising transport comes with its challenges, the main one being the existing transport refuelling network which is overwhelmingly geared towards fossil fuel vehicles. For electric vehicles there are the costs of taking electricity from the network, both in terms of generation costs and additional network capacity costs. However, much of this issue can be addressed by encouraging (or mandating) off-peak charging of vehicles.

Innovations in the transport sector such as electric vehicles and hydrogen fuel cell vehicles will provide challenges to the existing industry business models. These new business models offer opportunities for a new industry to develop, and challenge the fundamental business models and regulatory systems that have evolved over recent decades, also blurring the line between utilities as currently delineated.

The potential for transport decarbonisation highlights the need for a 'whole energy system' approach in the future, covering technology, customer needs, policy, regulation, and new business models.

Please see Appendix A for more details on the fuels and technologies we have looked at in our study.

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[20] UKERC The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios

4 Our scenarios

4.1 How we derived our scenarios

What is beyond doubt is that decarbonisation of heat will require change to the industry status quo. What is uncertain is what the change will be. This report looks at four possible future scenarios for how energy for heat will be delivered in 2050. Each scenario uses technology and fuels that is available and could, with the will and investment, start to be implemented today.

All our scenarios 'solve' the CO2 emissions target, i.e. they produce no more than 20% of 1990 CO2 emissions. It should be noted that we have only looked at emissions of CO2 in this study, which accounts for the majority of greenhouse gas emissions. We assume that other Greenhouse gas emissions are proportionality reduced but we have not investigated this further.

We recognise that in reality the energy system is highly unlikely to develop according to one particular scenario that we can set out today. The purpose of having these scenarios is to show a range of possibilities. To this end we have deliberately chosen contrasting scenarios. To develop our scenarios we considered two key variables:

- How much will gas continue to be used as a final source for consumers?
- Whether decisions about future energy use be taken locally or nationally (or both)?

Demand assumptions

To keep a consistent base, and ensure we are comparing like with like for each of our scenarios we have used one overall forecast of energy demand for all four scenarios. We have used the National Grid's Future Energy Scenarios (FES) 2015 'Gone Green' scenario for both overall and peak demand.

A key factor affecting future demand forecasts is the level of energy efficiency improvements that are assumed. There are some measures that are practical to achieve such as LED lighting, loft insulation, boiler replacement, but others require more difficult and expensive changes to the ageing existing housing stock. As such, we have lowered Gone Green energy efficiency saving assumptions (and so increased demand) to reflect our view of more realistic forecast energy consumption levels.

Assumptions for power and industry and other sectors

Our scenarios focus on different ways of supplying heat to domestic and business customers. We have assumed that other sectors that draw energy from the gas or electricity grid including heavy industrial usage will have the same fuel mix (either natural gas or electricity) as they do today. This includes the potential for biogas to be used as a substitute for natural gas. We have assumed that gas fired power generation will be used in the same proportion as it is today.

To ensure our study is as simple and focused as possible we have assumed that by 2050, outside of gas fired generation, all other electricity generation is decarbonised. Therefore any increase in electricity demand will need to be met by renewable and/or nuclear sources. This is a broad assumption we have made; we have not sought to assess how this may happen.

However, for the all-electric and prosumer scenarios, significant additional amounts of additional electricity is required with much of this sourced from intermittent renewables, especially solar that is unlikely to contribute to winter heating peaks. As such, we have assumed that a significant further proportion of flexible generation capacity will be needed as back up in these scenarios and have including this in our analysis.

See Appendix B for further detail on how we derived our scenarios and the assumptions we have made.

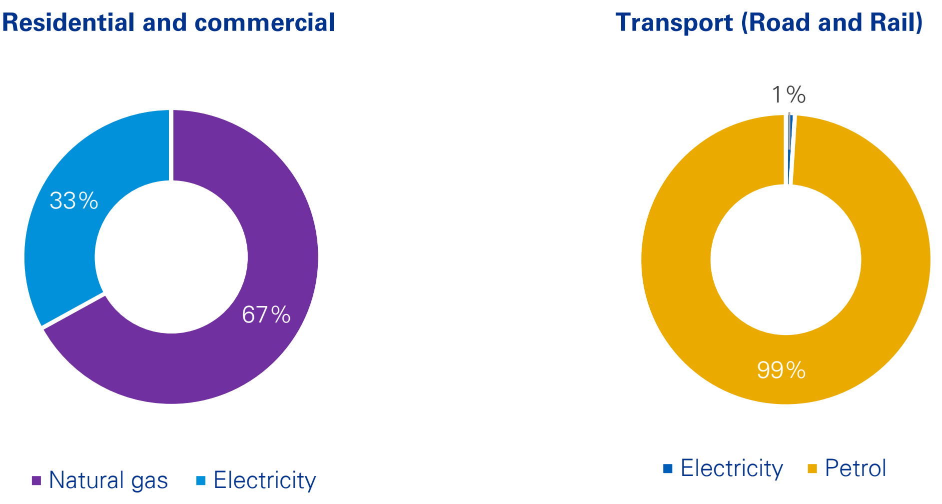
4.2 Assessment of our Scenarios

4.2.1 Cost Assessment

Our cost analysis is based on a comparison with a 'no change' or status quo scenario as a control. Our control is simply the energy system costs if there was no change to how energy was delivered today. In the control scenario, energy for heating is almost entirely natural gas (methane) with little incremental investment in energy networks and there is no household conversion cost. This is a not a realistic scenario as it does not meet the carbon reductions target. It is only used as a base with which to compare the different scenario costs.

4.2.2 Control scenario assumptions

Figure 4.1: The energy mix in 2050



Due to the large number of variables and uncertainties involved we have developed a potential range of costs for each scenario. The difference in ranges reflect high and low estimates of the cost inputs.

Energy commodity costs

This is the commodity cost over the whole period. Our control scenario assumes a certain volume and cost of gas and electricity is used, with residential and commercial demand split according to the percentages above. Each scenario then varies these percentages which varies commodity costs in each scenario.

We took the base prices from the National Grid Future Energy Scenario (FES) for gas and electricity costs and multiplied by the amount of energy (in TWh) that each scenario will require for each fuel type.

Capital costs

We have sought to calculate the incremental capital costs of implementing each of the scenarios as these will represent the most significant cost elements. We have taken a high level view of each of the major capital cost components of the entire energy supply chain that we expect to vary according to the scenario circumstances.

Network conversion costs (Gas and electricity)

We have calculated a cost per GW of additional capacity for each network (transmission and distribution electricity and gas[21]). For each scenario we have multiplied this by however many additional GW's of capacity is required for each network. Note that we consider network capacity costs to be driven by peak

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[21] Though none of our scenarios foresee an increase in gas capacity.

demand i.e. the highest number of GW's required at any one point in the year rather than the overall annual demand measured in TWh.

The network costs in our scenarios include assumptions on electricity storage. We assume that 10% of additional capacity is met through storage. However we assume that this storage is only short term (1-2 hours) for the highest peak times i.e. winter morning and evening peak as opposed to longer term seasonal storage.

For scenarios where hydrogen is used, gas network costs also include the costs of installing steam methane reformers to produce hydrogen from methane, which includes the costs of installing CO2 pipes to carry the CO2 bi-product to storage facilities.

For the scenario where heat networks are used (scenario 3) we include the costs of installing heat network pipelines and the cost of biomass facilities which we assume is the primary source of heat, we recognise that there are a range of other potential heating sources but have made this assumption to keep the scenario as simple as possible.

End user conversion costs

Based on information we have gathered from publicly available sources and industry, we have estimated the cost of converting residential and commercial properties from gas (with a gas boiler and cooker etc.) to the alternative heating technologies, hydrogen, heat networks, prosumer technologies and electric heating systems.

It should be noted that these costs relate only to changing heating sources. We have not sought to include the costs of road and rail transport conversion in these costs. We have made a broad assumption that as the asset life of vehicles is relatively short, if change is to happen, old petrol vehicles would gradually be replaced by the newer technology with no additional capital cost required.

4.2.3 Costs we have not included

Operational and financing costs

We have not included operational or financing costs within our calculations for any scenario due to the large amount of unknown factors. Capital and commodity costs are expected to be the most significant variables for each scenario.

Conversion incentives

In each of our scenarios, we assume that there will be conversion costs for networks, consumers, and the associated energy supply chain, and have made forecasts for each. However, these changes are unlikely to occur without incentives or mandatory obligations being put in place by Government and regulators to achieve the desired policy objective. We have made no assumption for the costs of such incentives but have recognised the barriers to change in the 'practicality' assessment for each alternative scenario.

Transport conversion costs

Where capital investment may be required is in the transport refuelling network, which would be critical to the success of electric and particularly hydrogen vehicles. We have not in this study sought to quantify this cost but it does form part of our analysis of practicality. Further research would need to be conducted into the cost and feasibility of converting service stations to Hydrogen and/or electric.

See appendix C for the full list of the cost assumptions that we have made.

4.2.4 Practicality assessment

Technical Feasibility

We have examined the technical challenges of changing from the status quo to new ways of delivering heating, the main areas include:

a) Feasibility of fuels and technologies

All the technologies featured in our scenarios use feasible technologies that have been demonstrated. We have not used untested technologies. These technologies range from the use of alternative gases such as hydrogen, to the use of heat pumps and energy storage technologies. Further details are provided in Appendix A. However some of the different systems being proposed have not yet been rolled out at scale and/or in a real 'live' environment, and therefore come with an element of uncertainty.

An often overlooked challenge is the ability of the supply chain to provide the components and appliances necessary on a readily available and simple commercial basis. Development of a supply chain (and associated skills and capabilities) is another potential barrier.

b) Meeting Peak demand

One of the biggest technical challenges for a network is meeting winter peak demand. Of all energy demands, energy for heat varies enormously between seasons, and any assessment of whether a particular technology or fuel is practically viable has to include an assessment of whether it can meet winter peak demand.

Customer Acceptance

a) Disruption of Changeover

Getting people to make changes is one of the most difficult things to do. Changes to heating appliances will inevitably result in a certain level of disruption to homes and businesses. Clearly the more disruption and 'hassle' a change will impose on customers, the more difficult change will be.

b) Functionality

Customer preferences for how they want their heat is key. The average customer wants their home and hot water heated when they need it, reliably and with minimum 'hassle' on their part. Often these considerations trump costs and carbon emissions. This can often be as much down to perception as actual practicality. If customers perceive that a heating method is not going to give them the functionality they want and have come to expect then this could be a significant practical barrier.

c) Impact on Space

The amount of space that a heating system could take up, no matter how effective and/or inexpensive it may be, will be a large barrier for a large number of customers. Approaching 80% of households have replaced their old boiler plus Domestic Hot Water (DHW) tank with a Combi boiler. They are a popular form of heating as they can release up to 1m^2 of floor space.

Societal & Political acceptance

a) New Infrastructure

Building new infrastructure in the UK is a practical and logistical challenge, particularly in populated areas where the majority of any new infrastructure will need to be located. Planning consents can take significant time to obtain, particularly for controversial projects. Streetworks legislation significantly increases the timescales (and costs) of installing new infrastructure.

b) Regulatory and market change

To an extent all scenarios will require policy and regulatory change, and by extension, changes to the market. The more extensive the changes to energy delivery systems, the more leadership and effort that will be needed from Government and Regulator to make the change happen.

Clear policy direction will be needed to ensure investor confidence with respect to both existing and new infrastructure investments. Major interventions are likely to require cross-party political support.

Transport acceptance

The decarbonisation of the heat sector (and the role of gas in this) is the primary focus of this report. However as the second largest energy consuming sector, any plan to decarbonise has to look at transport as well.

Each of our scenarios makes different assumptions about transport carbon emissions, the more heat is decarbonised the less transport needs to (i.e. the more oil can continue to be used in the transport sector) and vice-versa.

4.2.5 The ‘practical’ challenge

Although none of the above practical issues are insurmountable, the more and the bigger the practical challenges the bigger the effort (or non-financial capital) required by Government, regulators, the market and customer, adding to the ‘hidden’ cost of change. These hidden costs are just as vital as actual capital cost as if the practicality bar is set too high then considerable money and effort will need to be spent to make it work.

While this report has highlighted some high level economic and ‘practicality’ challenges for 2050 energy scenarios, it has not sought to identify roadmaps for addressing implementation plans, financing approaches, decision making, industry reform issues, etc. Further analysis will be required in this area.

5 Scenario 1 Evolution of Gas

5.1 Synopsis

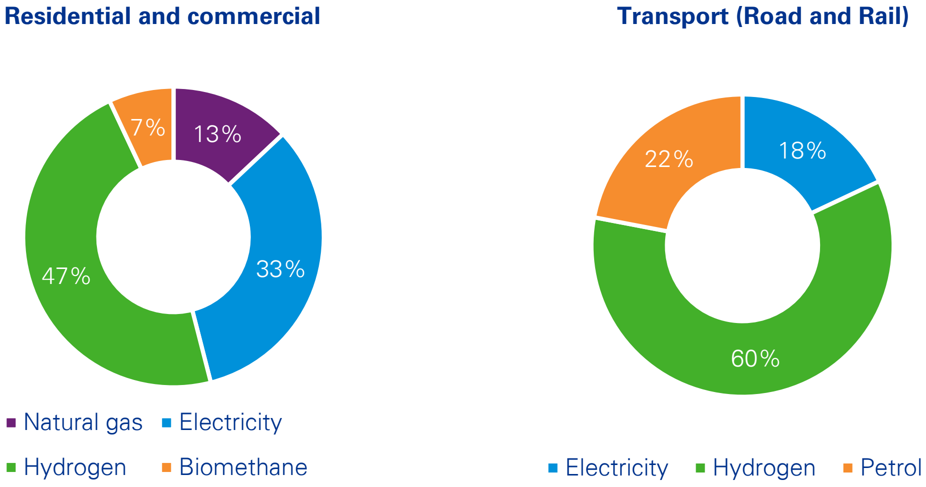
In this scenario the balance between gas and electricity as the fuel source for residential and commercial customers remains the same as today with gas providing the majority of heating and hot water energy. The difference is that an alternative gas, hydrogen, is used and the majority of the distribution network is converted to use hydrogen gas. Hydrogen fuel cell vehicles become the predominant form of road transport, accounting for the majority of transport energy demand.

5.2 A Cold day in 2050

Meet Jenny. It is a cold day in January 2050, and the temperature has dipped to -5C. Its 7am, Jenny gets up, her house is heated by a new hydrogen boiler. She runs a bath, the hot water is slowly making its way from the boiler. Waiting for the bath to fill, she puts the kettle on using electricity from the grid. Jenny takes the bus to work, powered by a hydrogen fuel cell. It is still -2C outside but the office is warm. The hydrogen boiler in the basement is firing up, heating up the building.

5.3 Scenario Assumptions

Figure 5.1: The energy mix in 2050



Residential and commercial

Transport (Road and Rail)

5.3.1 **Heating Fuel**

In this scenario, there is a gradual shift (city by city) towards the use of hydrogen technologies. By 2050 the majority (we have assumed 70% for cost calculation purposes) of residential and commercial gas customers use hydrogen as their source of heating energy.

The hydrogen for residential and commercial consumption is produced from natural gas transported via the National Transmission System to steam methane reformer (SMR) facilities to extract the hydrogen from methane. The hydrogen is transported via the distribution system to homes and businesses. 90% of the CO2 by-product from this process is transported to and stored in large CO2 storage facilities, with a large amount of this storage available in the North Sea. For our cost assumptions we have included the costs of building CO2 disposal infrastructure but not the ongoing cost of CO2 storage. While there are alternative methods of producing hydrogen such as the use of nuclear energy and electrolysis in our assumption, we have based our analysis on the method of extracting hydrogen from methane.

The remainder of gas customers continue to use methane as currently. The strict UK gas specifications, designed for North Sea gas, are relaxed allowing for a wider range of gas to be used in the system[22]. In particular this opens up a large amount of Biomethane which is fed into the network at a distribution level where it blends with the natural gas that is still delivered by the transmission system. In areas where methane is still used this scenario assumes that 30% of methane used by households and businesses is Biomethane. This methane still emits carbon emissions but less than just natural gas therefore emissions of this blended methane are lower.

National Grid Distribution's innovation projects on BIO-SNG, including a BIO SNG demonstration plant, have shown how large quantities of bio 'syn gas' can be manufactured and meet the specification of the grid[23].

As today the Natural Gas is sourced from LNG imports and imports from the gas interconnectors to mainland Europe. Shale gas becomes an important source of domestic gas (but does not replace the need to import natural gas).

The specifications of gas in the UK are widened, allowing for wider sources of gas to be injected into the grid. SGNs 'Opening up the Gas Market' innovation project demonstrates that the specifications can be widened[24] to allow for a greater variety of both natural gas (including LNG) and also biomethane and potentially shale without the additional need for processing. This could save on costs and carbon emissions (bringing gas specifications up can require propane which has high carbon emissions).

Those not connected currently to the gas network use a combination of hydrogen fuel cells and electricity as their heating source.

5.3.2 **Networks**

In this scenario the gas grid continues to deliver the bulk of heating energy. The way the network operates can be greatly transformed from a largely passive 'top down' system to a more intelligent and flexible network that is able to accommodate many alternative sources of gas. SGN's 'Real Time Networks' innovation project seeks to demonstrate how through innovative techniques driven by effective use of real data this more 'intelligent' gas network can be achieved[25].

The transmission system exists largely in the same form as today except a large proportion of the natural gas it carries is used to feed the SMR facilities that create the Hydrogen which then feeds the distribution system.

At the distribution level the iron mains replacement programme is completed which paves the way for hydrogen to be transported through distribution pipes with minimum additional conversion. The majority of

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[22] As demonstrated in SGN's Opening up the gas market project.

[23] National Grid BIO SNG demonstration plant innovation project.

[24] SGN's 'Opening up the gas market' project suggested that a widening of the Wobbe index from 46.5-51.5MJ/m3 to 46 – 54MJ/M3 would allow for 90% of LNg to be used without additional processing.

[25] The SGN innovation project 'Real time networks'

the distribution network is switched to supply hydrogen, this is particularly in areas where there is easy and ready access to carbon storage facilities.

Many small bio-methane suppliers connect to the remaining part of the network that is not converted to Hydrogen. Therefore the areas of the network that still use methane (which will increasingly be a blend of natural gas and Bio-methane) will be nearer to sources of bio-methane and also Bio SNG facilities which can ‘manufacture’ methane.

5.3.3 End user appliances

In the majority of the country all gas appliances (boilers, hot water tanks, cookers) are either replaced or converted to run on hydrogen. The remainder of gas customers’ appliances do not change.

We have not assumed an extension of the gas network. Therefore 10% of customers in rural areas remain off the gas grid. In this scenario we assume that these customers use a combination of electricity from the grid and hydrogen fuel cells that generate electricity. We assume that oil will no longer be used as a heating fuel by 2050.

5.3.4 Transport

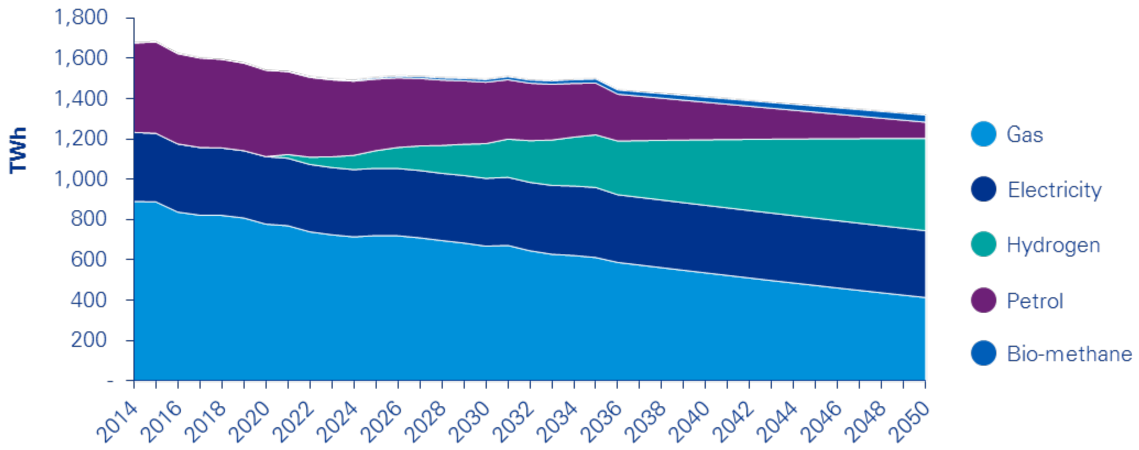
Hydrogen fuel cells vehicles make up the majority of road transport. The vehicle refuelling network evolves to become primarily a hydrogen vehicle refuelling network. In areas where the refuelling network is near to hydrogen distribution networks, the hydrogen network can help supply these hydrogen stations.

The rail network is completely electrified. Some electric battery cars are used, mainly for shorter urban journeys (e.g. taxi cabs). Only a small number of petrol vehicles (including hybrid vehicles) remain. Petrol pumps at service stations start to become a thing of the past, being replaced by hydrogen fuel service stations.

5.3.5 Demand

The chart below shows the fuel mix used to meet overall energy demand in scenario 1.

Figure 5.2: Total consumption by fuel



The chart below shows the fuel mix used to meet the peak power demand from the residential and commercial sectors in scenario 1.

Figure 5.3: Allocation of peak for residential and commercial

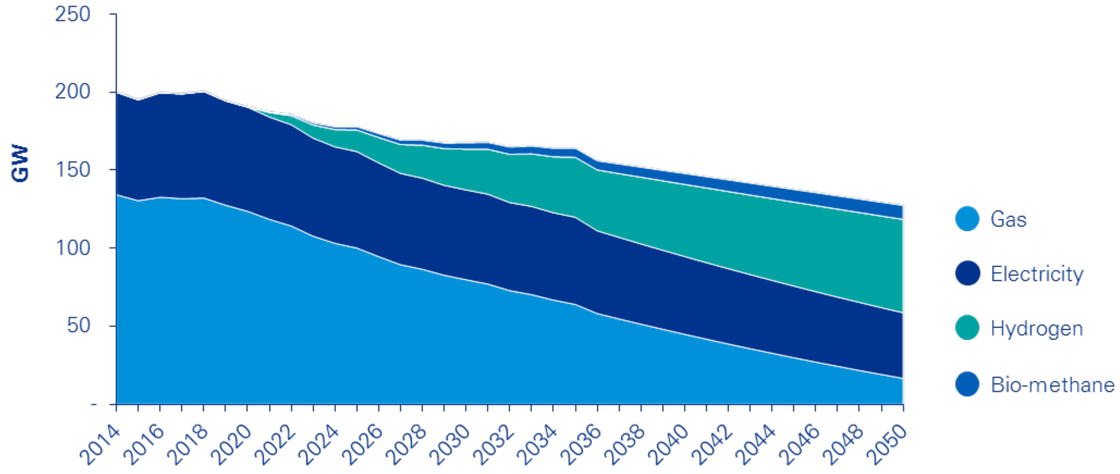


Table 5.1 below shows the total carbon emissions in Great Britain in 2050 for scenario 1.

Table 5.1: Scenario 1 - 2050 Carbon Emissions

	MtCO2e
Total CO2 emission allowance in 2050 for GB[26]	115
CO2 generated from the economy outside of our analysis	50
CO2 from road and rail transport	19
CO2 from Industrial and Electricity Generation (gas fired)	27
CO2 from heat	19
Remaining CO2 allowance	0

In this scenario heat continues to produce CO2 but this is offset by the large reduction in transport emissions as Hydrogen fuel vehicles become the predominant form of transport.

5.4 Scenario Assessment

Pros

- Relatively low capital costs
- Makes use of existing assets
- Small/ no change to customer premises
- Low use of space in people's homes
- Least 'hassle' option for customers.
- Less pressure on power generation

Cons

- Heating still carbon emitting, relies on using hydrogen in surface transport to meet the targets
- Hydrogen yet to be used at mass scale in either heat or transport sectors
- Need to convince public of safety of hydrogen
- Need to store large amounts of Carbon Dioxide

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[26] Excluding international Aviation and shipping

5.4.1 Costs

Cost Range: £104bn-£122bn

- This scenario is a relatively low capital cost given that it uses the existing gas network assets, assets that have already been paid for by customers.
- As this scenario continues to use gas there is a relatively small difference in commodity costs, mostly driven by the energy requirements of the steam methane reformer process.
- The building of steam methane reformers is a large gas network investment.
- There is relatively low amount of investment needed for household conversion. Although this is still substantial.

Table 5.2: Cost Breakdown

	Costs (£ billion)	
	Low	**High**
Incremental commodities cost [27]	21	21
Electricity networks	-	-
Gas networks	43	52
Household adaption	40	49
Total	104	122

5.4.2 Technological feasibility

Feasibility of fuels – Hydrogen untested, but methane a tried and tested source

Hydrogen is not yet proven at a mass market level. Gradual roll-out and testing will need to be conducted before it is rolled-out at scale. All of the components needed for Hydrogen conversion can be competitively sourced from a substantial variety of suppliers based within the EU. This ranges across both gas production and use.

Large Carbon capture and storage facilities (CCS), needed to store the carbon produced by the steam methane reformer process, are not currently widely used. However experience is growing with over 15 projects already constructed worldwide and a further seven under construction[28]. (See appendix A).

Methane gas is a tried and tested form of heating which customers are very used to. Bio-methane is already being injected into the gas distribution system and the production of BioSNG has been tested by National Grid Gas Distribution[29]. SGN's Opening up the Gas Market project has shown that extending gas specifications to allow for different natural gas sources (without any further treatment) is possible.

Meeting peak demand - Gas networks a proven way of delivering peak energy

Gas networks already meet peak demand and can continue to do so. The Gas network has considerable scope to become more flexible and responsive to customers' needs as it moves from a passive one way delivery system to a more 'intelligent' network that can handle a range of fuel types. SGNs 'Real Time Networks' innovation project aims to show how such an 'intelligent' gas system could develop.

5.4.3 Customer acceptance

Change Over – Relatively simple changeover of one boiler to another

Conversion to hydrogen will require access to each property for a few days (in summer), but the conversion in the house is the relatively simple process of switching one boiler with another. In this scenario a large minority of households and businesses are not required to take any action at all as they continue to use methane.

However a challenge of hydrogen switch over will be that whole areas will need to transition at once (e.g. over one summer) while methane is switched off and hydrogen switched on, which is a logistical challenge for people who are out at work and an affordability challenge, particularly for older and more vulnerable customers. The natural gas change-over was successfully achieved in the 1960's and 1970's for a similar number of appliances as today.

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[27] We have not used a range on the cost of commodities

[28] Large Scale CCS, CCS Projects, Global CCS institute.

[29] Commercial BioSNG Demonstration Plant, National Grid Network innovation project.

Functionality – same functionality as today

This scenario presents the most continuity to existing gas customers. The majority of customers will be required to convert to Hydrogen gas appliances, but these will present very similar functionality to current methane boilers. Essentially customers will continue to have the same convenient functionality that they enjoy today.

Impact on space - No additional space needed

Under this scenario heating and hot water is provided by one gas powered combination boiler using either methane or hydrogen. This takes up no more space in most customers homes than currently and may even be less by 2050 given the increased efficiency and smaller sizes of new boilers.

Financeability - Relatively low investment cost for customers

The majority of customers will need to replace/convert their existing boilers and gas appliances for hydrogen which will involve a relatively modest upfront cost. Alternatively, this conversion could be funded by network companies or suppliers and recovered through customer charges over time. Nevertheless even this modest conversion cost will be a challenge for many lower income customers and some form of subsidy or other assistance is likely to be needed.

5.4.4 Societal & Political acceptance

New infrastructure - Least new infrastructure

Although building steam methane reformers and converting the majority of the distribution network will not be a small undertaking, but relative to the other scenarios this scenario involves the least new infrastructure. The existing gas network continues to be used. The difficulty and disruption of building new infrastructure, particularly of having to dig up urban streets, is almost entirely avoided.

Regulatory change – least change to market structures

Under this scenario the current regulatory and market structure remain as it is today with regional and national monopoly regulated businesses, and competing energy suppliers. Much of this change could be realised safely and reliably through the existing regulated network company obligations. This approach would build on existing structures and seek to gain economies of scale.

5.4.5 Transport impact

Decarbonisation of transport – heavy reliance

Of all our scenarios this scenario decarbonises the heat sector the least and therefore there is a stronger reliance on transport to decarbonise, mostly via hydrogen fuel cell vehicles, in order to meet carbon targets. This is feasible but it will be a considerable challenge to persuade consumers and industry to switch.

Interaction with transport – potential gas networks to supply transport network.

One positive of this scenario is how the development of hydrogen networks could help facilitate a hydrogen vehicle refuelling network. Hydrogen vehicles present a way of significantly decarbonising transport sector which could be a low cost and practical way of meeting decarbonisation targets.

5.4.6 Summary

- Continuing to use the gas networks offers the lowest cost way of decarbonising heat with potentially the fewest practical barriers.
- However it is not complete decarbonisation, therefore transport will also need to be decarbonised considerably if targets are to be met.

6 Scenario 2 Prosumers

6.1 Synopsis

Prosumers are defined as end energy consumers who install decentralised energy and storage on site, i.e. at the point of final demand. Prosumers can be either residential customers, such as householders installing energy generation and storage on their property, or commercial customers, i.e. businesses, doing the same thing on (larger) commercial premises.

In our prosumer scenario more and more consumers, both residential households and commercial properties, will generate their own energy through the various self-generation technologies. Also individual and small scale energy storage becomes viable so that this self-generation can be stored and used at peak times. Winter peak heating demand that is not self-generated is supplied by electricity.

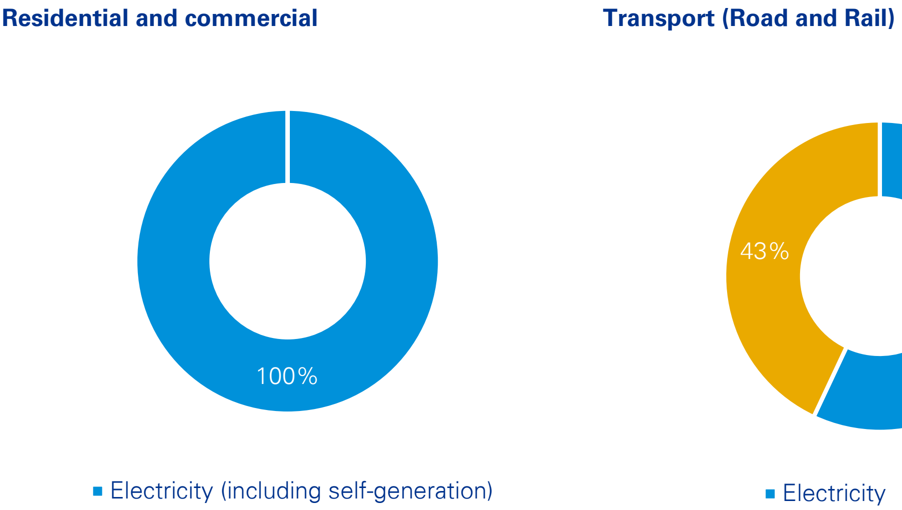
Under this scenario the gas distribution network is decommissioned and gas (in any form) is not used as a domestic heating fuel. Domestic appliances for heating and hot water are all converted to electricity or other heating methods such as air ventilation systems.

6.2 A Cold day in 2050

Meet Jenny. It is a cold day in January 2050, and the temperature has dipped to -5C. It's 7am, Jenny gets up, her house is warm: heat is drawing out from the heat storage tank in her garden shed, topped up overnight by off-peak electricity. She runs a bath, the water is heated up by the heat collected from the solar thermal system on the roof. Waiting for the bath to fill, she puts the kettle on using electricity from her electric car battery which had been charged overnight from grid electricity. Jenny gets an electric tram to work. It is still -2C outside but the office is warm. The electric air source heat pumps powered by solar and battery storage heats the building.

6.3 Scenario Assumptions

Figure 6.1: The energy mix in 2050



6.3.1 Heating fuel

This scenario assumes a drop in residential and commercial energy demand from the grid as many homes and businesses generate their own energy. However this self-generation does not replace the energy that gas provided (particularly at peak) and therefore the majority of energy needs are still provided by the electricity grid, resulting in a large increase in electricity generation capacity (though less than scenario 4 where all demand is met by grid electric)

6.3.2 Networks

The gas distribution network is completely decommissioned. The gas transmission network remains to supply industry, gas fired electric generation and interconnectors but is less utilised.

As in this scenario the majority of energy is still provided by the grid the electricity transmission and distribution network is expanded to cope with the additional capacity needed. (Though less so than scenario 4). We have assumed that the additional electricity distribution capacity needed to meet peak demand is met 90% by an increase in the network and 10% through electricity storage at a distribution level. We assume that the majority of this storage covers 1-3 hour maximum peak in mornings and evenings (and recharged during night) rather than long term seasonal peak. Over the whole year some Prosumers could produce more energy than they use and export to the grid - however at peak times they continue to draw electricity from the grid. Prosumer export at scale may exacerbate the challenge of balancing overall supply and demand in the future.

6.3.3 End user

The FES Gone Green scenario which we have used as a basis for our demand figures assumes that new homes are Zero Carbon by 2020, therefore this assumption is included in all our scenarios. This scenario goes further and envisages that the majority of commercial buildings and a minority of residential properties are retro-fitted with self-generation and storage technologies.

All residential and commercial gas appliances are switched from gas to electrical appliances. Heat pumps are a major source of heating particularly in properties with enough outside space. They provide continuous heat (rather than on demand heat). Underfloor heating is used for efficient space heating. In properties with lack of space, far less efficient resistive heaters may need to be used.

6.3.4 Transport

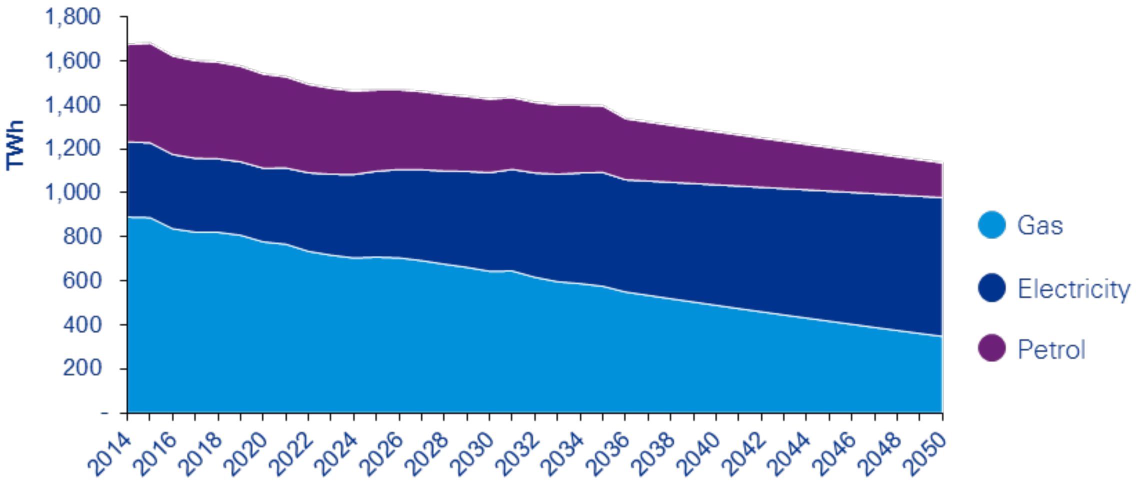
In this scenario there are significant amounts of electric vehicles with a national electric vehicle charging network to accommodate them. Electric vehicles work in harmony with prosumer self- generating technology and are charged in a smart way i.e. when the sun is shining and there is 'spare' electricity capacity.

All smaller vehicles and vehicles travelling shorter distances are electric. However larger cars and commercial vehicles are either hybrid or wholly petrol. Therefore petrol is still an important part of the transport energy mix.

6.3.5 Demand

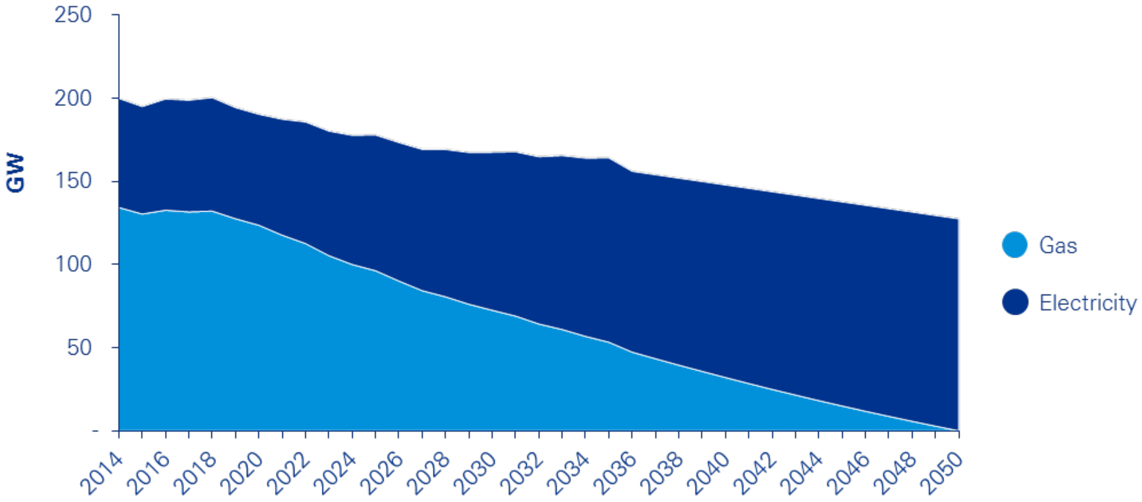
The chart below shows the fuel mix used to meet overall energy demand in scenario 2. Note that energy demand from the grid drops further compared with other scenarios to reflect the fact that many properties are self-generating.

Figure 6.2: Total energy consumption



The chart below shows the fuel mix used to meet the peak power demand from the residential and commercial sectors in scenario 2.

Figure 6.3: Allocation of peak for residential and commercial



6.3.6 Carbon emissions

Table 6.1 below shows the total carbon emissions in Great Britain in 2050 for scenario 2. We have calculated the amount of carbon emissions from the domestic and commercial sector that must be captured in order to meet the 2050 emissions reduction target.

Table 6.1: 2050 Carbon Emissions

	MtCO2e
Total CO2 emission allowance in 2050 for GB, excluding aviation and shipping	115
CO2 generated from the economy outside of our analysis	50
CO2 from road and rail transport in 2050 - petrol	38
CO2 from Industrial and Electricity Generation (gas fired)	27
CO2 from heat	0
Remaining CO2 allowance	0

We can see from the above table that in this scenario as heating is from electric sources (either prosumer or grid) it is not carbon emitting at the point of use. It should be noted that even with prosumer technologies being installed there will still need to be significant investment in non-carbon emitting electricity generation to meet this increased demand.

As we have assumed that heat is decarbonised a certain amount of petrol can continue to be used in the transport sector and still achieve the 2050 CO2 emissions targets.

6.4 Scenario Assessment

Pros	Cons
— Reduced energy commodity costs for adopters — Reduced energy demand on the grid — Near fully decarbonised heat sector allows for more flexibility in transport	— High capital costs of converting households to prosumer — High hassle factor for customers will limit take-up

6.4.2 How Much investment is required?

Cost Range: £251bn - £289bn

- This scenario has a high capital cost largely due to the cost of converting properties from gas to electric and installing prosumer technology.
- However overall commodity costs are reduced as more customers generate and store their own energy for their heating needs.
- However we have not assumed that enough customers will generate and (crucially) store their own energy to meet peak demand therefore there will be significant electricity network reinforcement costs, including costs of back up generation for intermittent renewables.

Table 6.1: Cost breakdown

	Costs (£ billion)	
	Low	High
Incremental commodities cost[30]	17	17
Electricity networks	22	26
Gas networks	7.2[31]	8.8
Household adaption	205	237
Total	251	289

6.4.3 Technical feasibility

Feasibility of technology – some individual technologies do work but unproven at scale

Some technologies envisaged in this scenario including heat pumps, and rooftop solar are established. Others such as long-term heat storage appliances have yet to be tested in a live market environment. It would also be necessary to upgrade the supply chain and associated installation skills of installers to the necessary standard.

Meeting peak demand – will be a considerable technical challenge to cover peak demand

This scenario relies on the majority of heat energy coming from the electricity grid, but providing enough electrical capacity to meet peak heating demand will be a considerable practical challenge. Individual heat storage is unlikely to have the ability to provide inter seasonal transfer for winter peaks, thereby potentially increasing electricity network capacity requirements even further.

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[30] We have not include a range on the cost of commodities

[31] This relates to decommissioning CSTS

6.4.4 Customer acceptance

Change Over – Considerable barriers to retro fitting homes and installing electric heating

Although making new properties 'heat neutral' (i.e. they produce their own heat), is feasible, 90% of today's properties will still be in use by 2050[32]. Retrofitting properties with heat generating and particularly heat storage technologies will be a considerable challenge. While a benefit of this scenario is that changeover can be gradual - the gas network can remain in operation until all properties in an area have switched to electric heating, this means that the cost of the residual network will fall on the remaining consumers.

Functionality – Householders will need to face limitations of heating system which could be a significant barrier

Heat pumps are effective continuous sources of air source heating but do not offer the same instantaneous 'on demand' heat as a Combi gas boiler. Electric heating can also not offer the same amount of hot water 'on demand' when needed. Once installed, the self-generating heating technologies should work without any additional effort from the customer, but some customers (particularly older and more vulnerable customers) may struggle to operate these systems.

Impact on space – Significant space required which would mean in many homes (may be easier for larger commercial properties)

This prosumer technologies will require significant amounts of space in properties. For new buildings it can be incorporated into the design of buildings but for retrofitted buildings providing enough space for sufficient solar generation and solar air collectors will be a real challenge. Furthermore, heat energy storage will also be a major challenge, particularly inter- seasonal storage (i.e. generating over summer for use in winter peak times). If this storage was via hot water, WWU's 'Cornwall Energy Island' project estimates that to provide sufficient heat each property would need an impractical 1400 hot water cylinders (160,000 litres) to store enough hot water.

While there is potential for other methods of heat storage to be developed by 2050, given the above limitations our scenario assumes that only a minority portion of heating energy is provided by self-generation and storage, with the rest from the electricity grid. However even here there are difficulties as heat pumps will require a certain amount of space (e.g. a small garden) to operate efficiently, plus a large DHW tank will be required.

Financeability –capital investment needed for prosumer technologies is a significant barrier to all bar wealthier, early adopters

The commodity cost savings for consumers, once self-generation technologies are installed, will be substantial. Again if included within new build, prosumer technologies it is viable way for a consumer to save money. However for retrofitting to existing homes the upfront capital investment (circa £30,000 for a domestic property higher still for larger commercial premises) is likely to prove a significant barrier to most. This equipment is also likely to need regular maintenance, and unlike current arrangements where such costs would be included in energy tariffs, this operational cost will fall on the individual customer.

Even for those who have little self-generation, the switch from gas to electrical heating appliances will also provide an upfront financing challenge.

6.4.5 Political and societal challenges

New infrastructure – required increase in electricity capacity will require significant new infrastructure

The replacement of the heating energy provided by gas with electricity will require significant new electricity network to be installed which will ensure a considerable amount of work in built up areas – and all the disruption that goes with this. Even with prosumers reducing the need for some of this additional electricity network there is still likely to be a significant amount of reinforcement required.

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[32] Managing Heat system decarbonisation, April 2016, Imperial college London

Regulatory and market change – no clear regulatory model

This scenario envisages householders and businesses taking more individual control of their energy reducing reliance on the existing regulatory and market structures. The electricity grid may develop into a more two way system with customers feeding back into the grid at certain times and areas of the country.

6.4.6 Transport impact

Decarbonisation of transport – less reliance on transport decarbonisation

This scenario assumes that the heat system is almost entirely decarbonised by 2050 thereby reducing the pressure on the transport network to decarbonise. The advantage of this is that petrol, with its established refuelling network, can continue to be used without the expense of establishing a new fuel. In this scenario plug in hybrid vehicles which use a mixture of electricity and petrol are used, reducing emissions while maintaining the convenience of being able to refuel quickly and easily.

Interaction with transport – additional pressure on the electricity network

In this scenario transport is significantly electrified (though liquid fuel still remains important). This could put additional pressure on an already heavily utilised electricity network.

6.4.7 Summary

- Prosumer technologies could have a role particularly for new housing and in rural areas not currently connected to the gas network.
- However as well as relatively high up-front costs there are significant practical barriers to retrofitting. Whilst attractive in principle due to reduced ongoing energy bills, it is unclear how many consumers can be encouraged to follow this path unless costs fall significantly.

7 Scenario 3 Diversified energy mix

7.1 Synopsis

This scenario envisages a ‘patchwork’ of energy solutions with each area of the country meeting its energy needs in its own way using methods appropriate for their area.

To present this at a high level we have assumed that each of the customers currently connected to the gas network will get their heat energy from one of four ways:

- Heat networks – where consumers pay for hot water rather than generate their own. We have assumed this heat is largely sourced from small Biomass plants. These will be the densely populated areas where heat networks are most effective (e.g.Inner London, Manchester, Birmingham, Glasgow).
- Hydrogen networks – this will be as per scenario 1 except fewer areas. These are likely to be areas nearest to large carbon storage facilities particularly industrial cities in the north and near the coast (e.g. Leeds, Newcastle, Sheffield, Aberdeen, and Edinburgh).
- Continue to use gas – as per scenario 1 except that smaller/fewer areas will keep using natural gas. Gas is sourced locally such as from shale and nearby LNG facilities. There is a higher concentration of bio-methane than in scenario 1 further reducing the carbon emissions of the natural gas used. This is likely to be in smaller cities, towns and suburban areas, near to sources of these gases and in particular around the major LNG terminals (e.g. Outer London, Birmingham, Manchester, Glasgow, South and South West, East Anglia, South Coast).
- Conversion to electricity – as per scenario 4, the local gas network is decommissioned and people in this area only use electricity. This is likely to be for the small towns and rural areas[33] where there is currently a gas network but are far from some of the sources above. Also in areas where there is a significant surplus of electricity generation such as Scotland.

In this scenario decisions on energy are taken at local government level with each town having one of the three network types: Hydrogen, Methane (Including Biomethane) or electric. Unlike Scenario 2 where people may make individual choices, in this scenario entire cities, towns and areas will use the same energy system. Municipal authorities are likely to play a key role in leading such initiatives.

7.2 A Cold day in 2050

Meet Jenny. It is a cold day in January 2050, and the temperature has dipped to -5C. Its 7am, Jenny gets up, her city centre flat is warm thanks to its connection to the local heat network. She takes a shower, drawing hot water direct from her heat network. She puts the kettle on using electricity from the grid. Jenny takes the bus to work powered by a Hydrogen fuel cell. It is still -2C outside but the office is starting to warm up. The large electric ground source heat pump is heating up the building. Worried by the cold weather Jenny video calls her mother at home in the outskirts of the city, her mother is nice and warm in the bath, heated by her gas combination boiler mostly powered by Biomethane derived from local farm waste.

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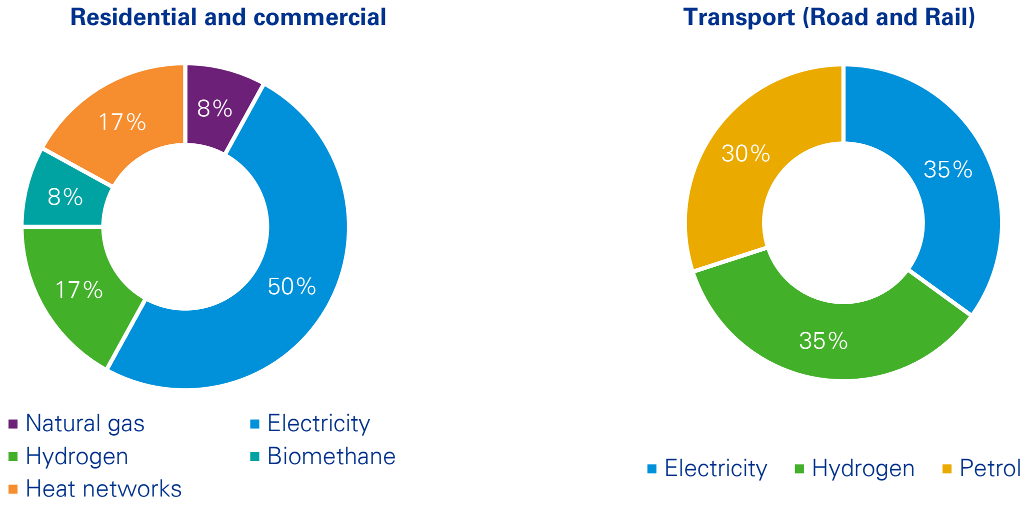
[33] Approximately 10% of households are not currently connected to the gas system, these will use electric heating.

7.3 Scenario Assumptions

Figure 7.1: The energy mix in 2050



7.3.1 Heating fuel

The Energy needed for heating is provided differently in each area:

- one quarter from hydrogen – as per scenario 1
- one quarter from electricity – as per scenario 4
- one quarter remain using methane – in this scenario we assume a high amount of locally sourced gas including from Shale gas and Bio-methane.
- one quarter from heat networks – the main heat source for this is biomass facilities which use bio-waste and/or wood chips. Back-up gas boilers are used to supplement this and ensure the heat networks can continue to supply energy at peak times. We have not included the commodity cost of bio-mass that feeds heat networks due to uncertainty about how significant this cost will be given a significant proportion may be provided by waste.

7.3.2 Networks

In this scenario energy will be distributed through local systems. A transmission network will continue to exist to transport natural gas from the LNG import facilities, any remaining UKCS gas, any larger shale gas fields and imports from interconnectors natural gas to heavy industry and gas-fired electricity generation. The amount of gas going through the remaining NTS will be greatly reduced.

Due to the increased electricity load from the quarter of customers that convert to electricity, the electricity networks will need to increase in capacity but to a limited degree. When deciding which areas should convert to electricity, the degree of spare capacity in these networks will be an important deciding factor.

In this scenario, we assume that half the gas distribution network is decommissioned in the areas that converts to heat networks or electric heating. One quarter is converted to Hydrogen (as per scenario 1) while the remaining quarter remains a methane network as it is today, though with a greatly increased number of distributed connections injecting Bio-methane into the local network.

Heat networks are built in the most urban and densely populated areas where they are most effective. Heat networks maintain a connection to the gas network and at peak times large back-up boilers are used to ensure a steady level of heat.

7.3.3 End user

Those areas that are switched to Hydrogen appliances are converted accordingly as per scenario 1.

In those areas with heat networks individual boilers are no longer needed. Any gas cookers are switched to electric.

In those areas that continue to use gas, all appliances remain as they are. We have assumed that injected Biomethane and/or other distributed gas sources will mix with natural gas so that the Calorific Value is within the same range as today and therefore alterations to appliance specifications are not required.

In electric only areas, heat pumps are used for space heating and electric boilers for hot water, as per scenario 4.

7.3.4 Transport

In this scenario, as for heat, road and rail transport is diversified with different fuels used for different purposes. Smaller cars and cars that make shorter urban journeys are electric. The rail network is completely electrified and most taxis are also electric or hybrid.

Hydrogen fuel cells are used for larger vehicles including HGV's, buses and commercial vans etc. A Hydrogen fuel cell network is developed, supplied by local hydrogen network but is relatively limited (compared to scenario 1) as hydrogen is not a mass-market transport fuel.

Petrol/electric hybrid vehicles plug the gap between the smaller urban electric only vehicles cars that are able to charge regulars and the larger hydrogen commercial vehicles. A minority of petrol only cars still remain. Overall petrol makes up a much reduced level of transport energy compared to today, circa 30%, but still plays an important role.

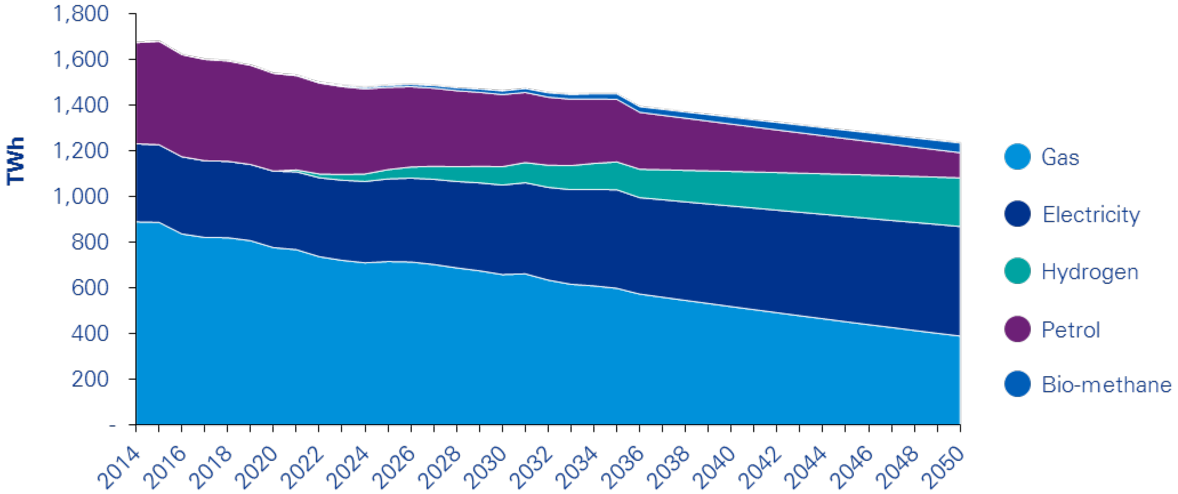
Road transport could even take on a regional aspect in this scenario:

- In urban areas where journeys are shorter and charging points more frequent electric vehicles are prominent.
- In areas where there's a hydrogen network, hydrogen fuel cell service stations become more economical and hydrogen fuel cell vehicles are more widely used (i.e. not just for HGVs).
- In other suburban and rural areas, petrol-electric hybrid vehicles are the norm as consumers are able to still refuel at service stations where needed.

7.3.5 Demand

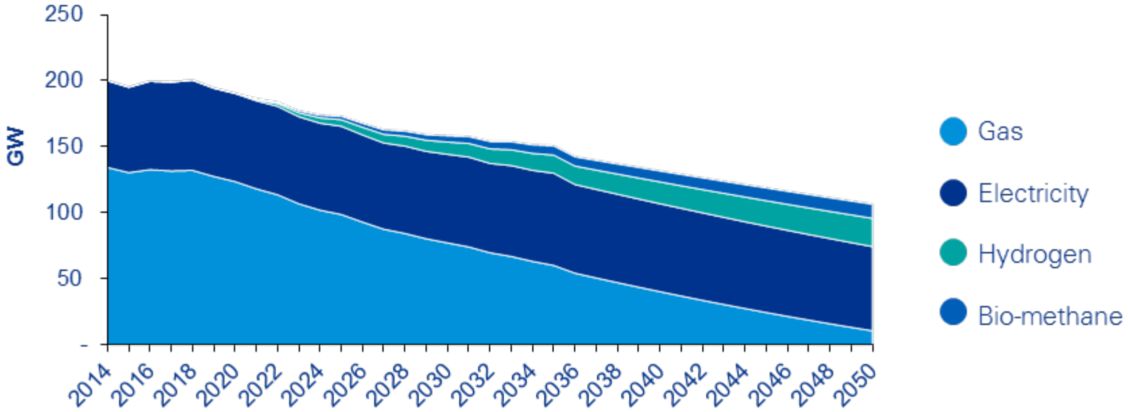
The chart below shows the fuel mix used to meet overall energy demand in scenario 3.

Figure 7.2: Total energy consumption



The chart below shows the fuel mix used to meet the peak power demand from the residential and commercial sectors in scenario 3.

Figure 7.3: Allocation of peak for residential and commercial



7.3.6 Carbon emissions

Table 7.1 below shows the total carbon emissions in Great Britain in 2050 for scenario 3. We have calculated the amount of carbon emissions from the domestic and commercial sector that must be captured in order to meet the 2050 emissions reduction target.

Table 7.1: 2050 Carbon Emission

	MtCO2e
Total CO2 emission allowance in 2050 for GB,	115
CO2 generated from the economy outside of our analysis	50
CO2 from road and rail transport in 2050 - petrol	26
CO2 from Industrial and Electricity Generation - Gas	27
CO2 Emissions from heat	12
Remaining CO2 allowance	0

In this scenario the decarbonisation effort is a mixture between heat and surface transport. The continued use of gas in some areas accounts for the remaining CO2 emissions.

In surface transport some petrol is still used as a fuel along with both electricity and hydrogen.

7.4 Scenario Assessment: Scenario 3 Diversified energy mix

Pros	Cons
— Local areas can choose the heating fuel that works well for them	— Relatively high capital costs — Potential confusion and lost economies of scale as a result of differing local systems

7.4.1 How Much investment is required?

Cost Range: £156bn- £188bn

- In this scenario all the cost drivers of scenario 1 and 4 are also present here but at a smaller scale.
- This scenario does assume some use of existing assets in some areas but building of new assets in others hence costs are relatively high.
- Heat networks are be built from scratch in urban areas and include costs of biomass facilities to provide the heat, thus are a significant part of this scenario.
- The cost of converting appliances within the home for heat networks is included in household adaption costs

Table 7.2: Cost Breakdown

	Costs (£ billion)	
	Low	**High**
Incremental commodities cost [34]	20	20
Electricity networks	1	2
Gas networks	19	23
Heat networks	62[35]	77
Household adaption	54	66
Total	156	188

7.4.2 Technological feasibility

Feasibility of technology – all technologies and fuels feasible some untested at scale

Some technologies envisaged in this scenario including heat pumps, electric conversion, and heat networks, are tried and tested and feasible at scale. Others such as hydrogen are untested at scale.

Meeting peak demand – variance in how heat is delivered will make meeting peak easier but likely to be local 'pinch points'

An advantage of this scenario is that there is no single source dominant source of energy across the country which should make it easier to meet peak demand. For example in this scenario a quarter of current gas customers will switch to electric heating, this will present a challenge for electricity generation capacity but should be more achievable than switching all customers to electricity. For remaining customers, gas networks and heat networks should be able to easily meet peak demand.

7.4.3 Customer acceptance

Change Over – considerable challenge for areas that do switch but this is avoided in some areas.

In urban areas retrofitting heat networks will be a considerable challenge. Evidence from the WWU Bridgend study suggest that voluntary take up from customers will be very limited. In other areas conversion to hydrogen will present a challenge, particularly given the need to convert whole areas over one summer (see scenario 1)

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[34] We have not included a range on the cost of commodities

[35] As our control scenario does not assume any heat networks, this is entirely new cost of building a bio-mass sourced heat network

and conversion to electric heating in suburban/rural areas will also be a challenge although there is the advantage of a more gradual switchover (see scenario 4). However changeover challenge is avoided in areas that remain using methane.

Functionality – most customers will have similar functionality to today but the more rural/suburban third will have more limited functionality.

For customers, heat networks should provide the same functionality that they currently receive from their combination boilers although any customers with gas cookers will need to switch to electric. Those areas that continue to use methane and those that switch to hydrogen can obviously expect the same functionality.

Heat pumps are effective continuous sources of air source heating but do not offer the same instantaneous 'on demand' heat as a Combi gas boiler (see scenario 4). In this scenario there is a potential for customer opposition in the areas that switch from gas as they may perceive their heating to be inferior to the rest of the country.

Impact on space – variance in technologies could make the most of the space available

A benefit of this scenario is that it can make the most of the space available. In rural and suburban areas electric heat pumps will have sufficient space to operate effectively. Heat networks require limited space within properties and are therefore best suited for urban areas where space in properties is more limited. In other areas where gas or methane is used there is no more use of space than there is today.

Financeability – upfront investment needed by consumers will vary and there will be greater variance in the cost of heating between regions

In all areas bar those that continue to use methane, there will be an upfront capital costs. These will have to be met by consumers or government through subsidies/incentives. Costs will vary with hydrogen conversion cost being relatively low (installing a new boiler) while switching to electric heating (installing heat pumps etc.) will be higher. Heat network conversion costs will be relatively low at household level with boilers being replaced by Hydraulic Iinterface Units (HIUs), but new heat networks will be expensive to install, especially where retro-fitting is required.

Consumer bills will probably vary by region as customers using new electricity and heat networks will need to pay for incremental heating costs are compared to those remaining on existing energy systems.

7.4.4 Political and organisational challenges

New infrastructure – installing heat network pipes in urban areas will be a considerable logistical challenge, minimal barriers in other areas

Heat networks will require whole new pipe networks to be laid under urban areas where it is most difficult (and costly) to conduct streetworks. The logistical challenge of this will be very large and likely to lead to local opposition to such upheaval.

The replacement of the heating energy provided by gas with electricity will require significant new electricity network to be installed in this scenario. This will mainly be in less built up areas where the disruption may not be so great.

Regulatory and market change – would require overhaul of the regulation and the energy market

In this scenario the regulation and market system will need to undergo a significant change from a national energy system to local and regional systems.

Heat networks are natural monopolies and if they are to become a significant part of the sector then they will need to be regulated. To be rolled out at scale heat networks will either need private sector investors who would expect a steady return or through public financing. There is currently no private funding model in place and local authorities have many competing demands on their budgets.

7.4.5 Transport impact

Decarbonisation of transport – some petrol

This scenario falls between our other scenarios. Residential and commercial heat is not fully decarbonised as in scenarios 2 and 4 and therefore there is greater reliance on transport decarbonisation through both electricity and hydrogen fuel cells. However this scenario decarbonises heat more than scenario 1.

Interaction with transport – additional pressure on the electricity network.

In this scenario transport is significantly electrified (though liquid fuel still remains an important fuel) this could put additional pressure on an already heavily utilised electricity network.

7.4.6 Summary

- This scenario could be effective as different heating solutions can be deployed in areas where they are most effective.
- However the move to regional energy systems will create an upheaval in industry governance, and some of the technologies used face a number of financial and practical barriers if they are to be deployed.

8 Scenario 4 Electric future

8.1 Synopsis

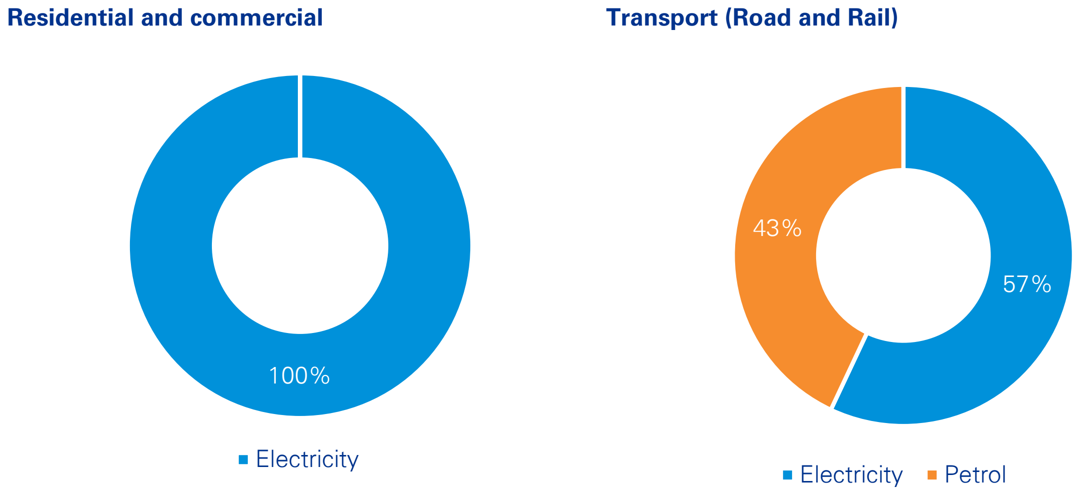
The Electric Future scenario represents a complete switch to the national electricity network. The gas distribution network is decommissioned and the gas transmission network is scaled back. All energy demand is met by the electricity network with some large scale storage to smooth the peak. Electric vehicles become the main form of transport, either as electric only or petrol-electric hybrids.

8.2 A Cold day in 2050

Meet Jenny. It is a cold day in January 2050, and the temperature has dipped to -5C. It’s 7am, Jenny gets up, her house is warm, heated from her electric air source heat pump. She runs a bath, the hot water is slowly making its way from her electric boiler. Waiting for the bath to fill, she puts the boiling water tap on for her cup of tea, using electricity from the grid. Jenny takes an electric tram to work. It is still -2C outside but the office is starting to warm up a large electric ground source heat pump is heating up the building.

8.3 Scenario Assumptions

Figure 8.1: The energy mix in 2050



Residential and commercial

Transport (Road and Rail)

8.3.1 Heating Fuel

In this scenario Natural Gas is only used to supply industry (via the NTS) and gas fired electricity generation. Gas (of any type) is not used for residential and commercial demand.

All residential and commercial energy needs are provided by the electricity grid, resulting in a large increase in electricity generation capacity.

8.3.2 Networks

The gas distribution network is completely decommissioned. The gas transmission network remains to supply industry, gas fired electric generation and interconnectors but the gas flowing through it is greatly reduced.

The electricity transmission and distribution networks are greatly expanded to cope with the significant additional capacity needed. Additional electricity network capacity needed to meet peak demand is met 90% by an increase in the network and 10% through storage at a transmission or distribution level.

8.3.3 End User

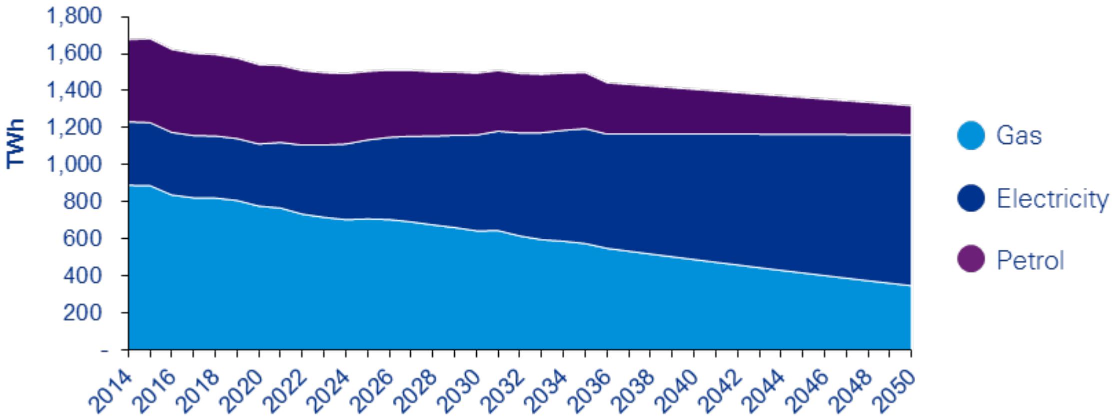
All residential and commercial gas appliances are switched from gas to electrical appliances. Ground and air sourced heat pumps as the main source of space heating, with electric boilers providing hot water.

8.3.4 Road and rail

In this scenario there are significant amounts of electric vehicles with a national electric vehicle charging network to accommodate them. All smaller vehicles and vehicles travelling shorter distances are electric, however larger cars and commercial vehicles are either hybrid or petrol only, HGVs remain as petrol. As a result, petrol is still an important part of the transport energy mix, with circa 45% of transport energy demand, albeit greatly reduced compared to today.

The chart below shows the fuel mix used to meet overall energy demand in scenario 4.

Figure 8.2: Total consumption by fuel



The chart below shows the fuel mix used to meet the peak power demand from the residential and commercial sectors in scenario 4.

Figure 8.3: Allocation of peak for residential and commercial

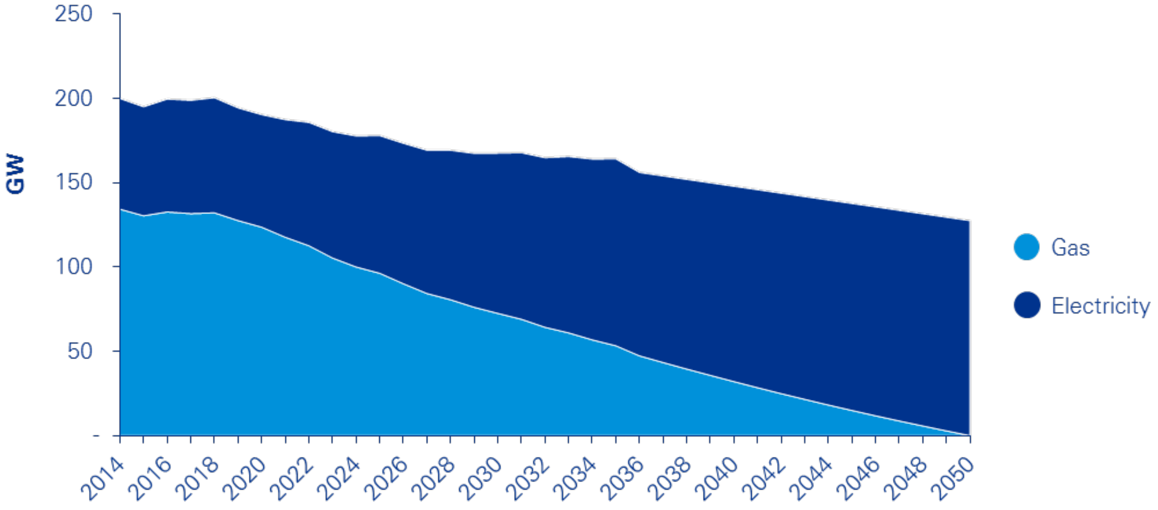


Table 8.1 below shows the total carbon emissions in Great Britain in 2050 for scenario 4. We have calculated the amount of carbon emissions from the domestic and commercial sector that must be captured in order to meet the 2050 emissions reduction target.

Table 8.1: 2050 Carbon Emissions

	MtCO2e
Total CO2 emission allowance in 2050 for GB, excluding aviation and shipping	115
CO2 generated from the economy outside of our analysis	50
CO2 from road and rail transport in 2050 - petrol	38
CO2 from Industrial and Electricity Generation - Gas	27
CO2 Emissions from heat	0
Remaining CO2 allowance	0

This scenario assumes that most of the decarbonisation target is met through decarbonising heat by using electricity. It should be noted that this scenario will require a lot more non-carbon electricity generation to be connected to the grid.

As we have assumed that heat is decarbonised a certain amount of petrol can continue to be used for transport and still achieve the 2050 CO2 emissions targets.

8.4 Scenario Assessment: Scenario 4 All Electric Future

Pros	**Cons**
— Proven technology that can be made to work — Can make the heating system carbon free if electricity generation is decarbonised	— High capital and commodity costs — Existing assets not used — Large practical difficulties around space — Significant hassle for consumers

8.4.1 How Much investment is required?

Cost Range: £274bn- £318bn

- High commodity costs in this scenario due to high electricity prices as electricity generation is decarbonised
- High network costs as electricity system has to take on the full peak demand that the gas system used to supply. Significant additional flexible electricity generation is required to back up intermittent renewables.
- Largest cost is household conversion as every property fitted with heat pump or electric boiler.

Table 8.2: Cost Breakdown

	Costs (£ billion)	
	Low	**High**
Incremental commodities cost [36]	115	115
Electricity networks	26	43
Gas networks	7.2[37]	8.8
Household adaption	126	152
Total	274	318

8.4.2 Technical feasibility

Feasibility of technology – proven but some doubts about actual efficiency of heat pumps

All technically proven, but significant shortfalls of actual annual efficiency of heat pumps are evident versus laboratory tests. Many smaller properties will not have the space for an Air Source Heat Pump (ASHP).

Meeting peak demand – will be a considerable technical challenge to meet peak demand

Providing enough electrical capacity to meet peak heating demand will be a considerable practical challenge. Electrical storage is an option but is a very expensive means of inter-seasonal storage.

8.4.3 Customer acceptance

Change Over – challenge to persuade population to switch but can be done gradually to reduce potential impact

Changeover from gas to heat will require new appliances, rewiring etc. It will prove a challenge to persuade many customers to part with their gas boilers. However a benefit of this scenario is that changeover can be gradual. The gas network can remain in operation until all properties in an area have switched to electric heating, but the costs of the residual gas network may have to be paid by decreasing numbers of remaining customers.

Functionality – Householders will face new limitations of heating systems which could be a significant deterrent

Air source heat pumps are effective continuous sources of heating but do not offer the same instantaneous ‘on demand’ heat as a Combi gas boiler This leads to continuous heating rather than ‘morning and evening’ bimodal

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[36] We have not included a range for the cost of commodities

[37] Decommissioning costs only

heating. This increases average internal temperatures and thus overall energy demand. Domestic hot water (DHW) supply is limited by tank size, thereby limiting ‘on demand’ hot water.

Impact on space – Significant space required which would mean in many homes (may be easier for larger commercial properties)

Heat pumps will require a certain amount of space (e.g. a small outside space or garden) to operate efficiently. A sufficient size DHW tank will also require significant space. The average property may not have the space available, particularly in more urban areas.

Financeability – Installing new electric system a high upfront cost

The switch to electrical heating appliances is significant will provide an upfront financing challenge. Some kind of subsidy and assistance is likely to be required, particularly for vulnerable and/or fuel poor customers. Alternatively, this could be recovered over time through charges from regulated network companies or energy suppliers.

8.4.4 Societal and political acceptance

New infrastructure – required increase in electricity capacity will require significant new infrastructure

The replacement of the heating energy provided by gas with electricity will require significant new electricity network to be installed which will ensure a considerable amount of work in built up areas – and all the disruption that goes with this.

Regulatory and market change – electricity market structure remains unchanged

This scenario could be delivered under the existing electricity regulatory and market structure.

8.4.5 Transport impact

Decarbonisation of transport – less reliance on transport decarbonisation

This scenario assumes that the heat system is almost entirely decarbonised by 2050 thereby reducing the pressure on the transport network to decarbonise. The advantage of this is that petrol, with its established refuelling network, can continue to be used and the expense of establishing a new fuel. In this scenario plug in hybrid vehicles which use a mixture of electricity and petrol are used, reducing emissions while maintaining the convenience of being able to refuel quickly and easily.

Interaction with transport – additional pressure on the electricity network.

In this scenario transport is significantly electrified (though oil still remains an important fuel). This could put additional pressure on an already heavily utilised electricity network.

8.4.6 Summary

- This scenario allows for near complete decarbonisation of heat.
- However it has high investment cost and considerable practical barriers to overcome.

9 Conclusions

9.1 Scenario assessment

The key features of the alternative scenarios are summarised below.

Table 9.1: Summary of scenario assessment

	Scenario 1 Evolution of Gas	Scenario 2 Prosumer	Scenario 3 Diversified energy sources	Scenario 4 Electric Future
Costs	**£104bn - £122bn**	**£251bn - £289bn**	**£156bn - £188bn**	**£274bn - £318bn**
Technical Feasibility	— Gas networks already meet peak demand — Hydrogen well understood but conversion yet to be tested at scale — No additional storage needed to cover peak	— Major difficulty in meeting peak heat demand — Large amount of interseasonal heat storage a major barrier — Large electricity back up capacity needed to cover renewable intermittency — Prosumer technologies not yet tested at scale	— Meeting peak is achievable, with additional investment in some areas — Uses available local resources — Some storage needed in some scenarios	— Major difficulty in meeting peak demand — Large amount of interseasonal heat storage a major barrier — Large electricity back up capacity needed to cover renewable intermittency — Overall technology proven and well understood
Customer acceptance	— Functionality and space requirements the same as today — Customers may be reluctant to change	— Very challenging to get consumers to accept different functionality — Space not available for many customers — Affordability will be a major barrier	— Regional differences in functionality — Restrictions on available space and access — Customers may be reluctant to change	— Heat pumps efficient but challenging where space is limited — Challenging to get consumers to accept different functionality — Affordability will be a major barrier
Societal & Political acceptance	— Limited disruption from new gas infrastructure — Acceptance of new CO2 disposal facilities required	— New electricity infrastructure will cause significant disruption — Domestic retrofitting will be a considerable challenge	— Considerable disruption in urban areas from heat network installation — Regional systems untested in UK	— Significant urban disruption as electric infrastructure is reinforced — Domestic retrofitting will be a real challenge

9.2 Summary of key findings

9.2.1 Cost of change

Large investment will be needed to decarbonise the heat sector which ever option is chosen; meeting winter peak heating demand is a critical cost driver

Decarbonising heat by 2050 is going to require significant capital investment whichever method of decarbonising energy is used. Gas is the main source of heat and is an instant, cheap and reliable means of heating.

Our analysis shows that removing gas from the energy mix and replacing it with electrical energy, while feasible, is higher cost and potentially more disruptive to customers. A major reinforcement of the electricity system would be needed to cope with the significantly increased (more than doubling) of peak winter energy demand, replacing the existing 'sunk' gas system investment costs at customer premises and in the gas network and gas supply chain.

Large investment will be needed to convert homes and businesses to new energy sources

For all scenarios, homes and businesses will face significant costs of conversion on their premises as well as across the remainder of the energy system. The legacy housing stock, with low replacement rates, poses a significant challenge in terms of retrofitting costs and feasibility of change. Costs of change in the home are the most significant and are significantly different depending on the technology used in each scenario. Gas conversion is the lowest cost as it largely uses existing assets, whereas heat networks, prosumers and electric conversion are higher cost.

For example, prosumers generating their own electricity and then (crucially) storing at least some of this energy for peak use can play a role in the decarbonisation of the electricity system. This is particularly the case for new housing and we would envisage much of new housing being at least partially prosumer. However the cost and practical implications of converting existing housing stock to generate enough to not need a gas grid connection is significant. It does not seem that prosumer technology alone can replace the energy delivery of gas or electricity networks.

Continuing to use the gas network offers significant savings versus alternative heating sources

Gas is a relatively inexpensive and efficient source of energy particularly for heating which makes up the bulk of our domestic energy requirements. Methane from natural gas can be supplemented by Bio-methane which can reduce the carbon emissions of gas. However methane (even with a Biogas blend) cannot continue to be used as today if we are to meet the 2050 decarbonisation target. Gas needs to be at least partially decarbonised.

Our analysis shows that converting customers to Hydrogen is a relatively lower cost option that continues to use much of the existing infrastructure and continues to use gas as the source fuel which helps keep costs low in comparison to other options. Converting to hydrogen will still come with significant costs, particularly the installation of steam methane reformer and CO2 storage facilities.

Overall costs can be kept low by only converting enough areas of the country to meet carbon emission targets. In our 'Evolution of Gas' scenario we have assumed that by 2050, 70% of current gas connections are converted to run on Hydrogen leaving the remainder to continue to use methane (including Biomethane). This scenario assumes that a significant amount of transport uses hydrogen fuel cells and is therefore decarbonised. If there is no decarbonisation of transport then more gas consumers will need to be converted to Hydrogen which will push up overall costs.

Transport decarbonisation will need to take place alongside heat to minimise whole system costs

Our analysis focuses on decarbonisation of the energy system. However, not all decarbonisation can come from power and heat. Decarbonisation of road and rail transport will be required to help meet targets. If the majority of transport is decarbonised then the pressure on the energy sector to decarbonise is reduced. More relatively cheap and effective natural gas can be used and capital costs are significantly less as there is less major change to infrastructure and individual premises.

9.2.2 Practicality of change

Decarbonisation of heat will require a major fuel source change

Our analysis has looked at possible futures for the energy system and associated energy networks in 2050. The energy market will need to adapt from selling gas (methane) to also sell and deliver other decarbonised fuels such as Hydrogen to customers. If Hydrogen does become part of the energy market then decisions will need to be taken, such as who will be responsible for the steam methane reformer process networks, CO2 storage networks, and how will hydrogen suppliers operate in the market? Regulatory and market arrangements will need to adapt accordingly.

Customers value the convenience and reliability of the current heat system, which presents a barrier to change

Gas provides an instant, safe, cheap and reliable source of heat. Evidence from the WWU Bridgend study indicates that customers are reluctant to change and may require significant incentives in order to change their heating system to a heat network, for example.

Practical issues for customers such as space, affordability and changed performance present a barrier to change

Some alternatives to gas for heating require additional assets to be installed, such as heat pumps or energy storage devices. Practical issues such as access, space, changed performance, affordability and ability to change will impact significantly on a customers' desire or ability to change. Also, a change may require additional ongoing costs to be incurred such as maintenance or safety checks which they may be reluctant to do.

Major changes to energy systems and installation of new networks will face practical planning and installation challenges

The current energy system is largely a national production and delivery system with mass produced or sourced energy distributed to local areas and individual premises. Some local energy sources have been developed but remain a small minority of the overall mix. The existing gas and electricity network is well established and has critically gained rights of way to its points of delivery. New or enhanced heat and electricity networks will face significant challenges in obtaining access to buildings, roads, routes, etc, for their pipes and cables.

9.3 Policy implications and recommendations

Policy and regulatory decisions are needed on the future pathway for gas and heat. Without such decisions, there is a risk that families and businesses will pay more than they need to and decarbonisation targets will not be met.

Each scenario in this report represents a stylised view of a 2050 future in order to assist thinking of future industry strategies and policies. As such, it is unlikely that any one scenario will present a perfect view of the future in 2050, but each may have elements that are realised.

In this context, it will be important that forthcoming policy decisions do not close off potentially attractive options for the future, and ensure that customers do not pay more than they need to.

Long term energy regulatory and market frameworks need to be consistent with the 2050 options.

Similarly to ensuring 'no regrets' policy options, regulatory and market frameworks should seek to enable rather than prohibit potential future scenarios. This may, for example, include the further development of initiatives such as SGN's 'real-time networks' project which seek to ensure that existing gas supplies are delivered as efficiently as possible through more efficient operational and gas quality management.

Transport decarbonisation policy needs to be integrated with energy decarbonisation policy and planned over the same timescales

Over the last decade, decarbonisation of power has dominated the achievement of emissions targets. In future, heat and transport will need to play a significant role. A whole energy system approach for 2050 will be needed if targets are to be realised in the most economic and efficient way.

Due to the long term nature of network investments, policy decisions need to be firmed up ahead of the next RIIO network price controls

The next RIIO price controls are due to take place in 2021 for gas networks. Investments agreed as part of these price controls will be in place for 2050, and will need be compatible with a trajectory towards one or more of these 2050 scenarios. In order for such major decisions to be taken, sufficient detailed advance analysis and understanding would be required to support these long term decisions.

Major investment is needed to realise 2050 targets. Government will need to decide how investment will be financed

Each scenario has identified significant new investment. This investment is needed on customer premises, networks and the energy supply chain for each scenario. Whereas regulated network companies may be able to obtain additional funding through their price controls, customers own works and those of energy suppliers/producers will ultimately need to be recovered from energy customers, or taxpayers. Additional incentives may also be required to persuade customers to switch their energy source.

There are a number of choices for funding new investment, although all costs will fall on taxpayers or customers. It may be funded direct by Central Government or Local Authorities from taxes, through network company charges, by customers for works on their premises, through energy suppliers, or by other private third party providers. For a national conversion exercise, there may be benefits from using regulated companies for a safe and efficient planned roll out.

More detailed assessment on the practicality of major change is needed, particularly about acceptance of change by consumers and society

The national changeover to natural gas took place in a very different industry and public environment to today. Customer, political and social aversion to change will have a significant impact on the success of implementation. Public understanding of costs and benefits will be very important to gain public and political support for a successful change.

Innovation funding and piloting needs to continue, especially in areas that help to firm up the understanding of options for 2050

All of the scenarios make assumptions about new technology advances. Development and piloting of applications will be critical to both gain a deeper understanding of performance and implementation.

10 Appendix A: Future Technologies

10.1 Alternative Gases

10.1.1 Hydrogen

As a pure element Hydrogen leaves no carbon footprint, the only product of its combustion is water. Therefore at the point of use Hydrogen is a clean source of energy. However, unlike Natural Gas (Methane), Hydrogen is not found naturally. It has to be industrially produced. There are different ways of producing Hydrogen, the main two methods of using nuclear energy to produce Hydrogen in large quantities are:

Steam Methane Reforming (SMR)

Derives Hydrogen from Natural Gas leaving CO2 as a by-product. Methane reacts with steam at approximately 25 bar pressure (1 bar = 14.5 psi) in the presence of a catalyst to produce hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide. Steam reforming is endothermic—that is, heat must be supplied to the process for the reaction to proceed. Subsequently, in what is called the "water-gas shift reaction," the carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen. In a final process step carbon dioxide and other impurities are removed from the gas stream, leaving essentially pure hydrogen[38].

Electrolysis

This is the process of using electricity to split water into hydrogen and oxygen. This reaction takes place in a unit called an electrolyser. Electrolysers can range in size from small, appliance-size equipment that is well-suited for small-scale distributed hydrogen production to large-scale, central production facilities[39].

Although hydrogen is a clean fuel at the point of use, to be a truly green fuel its production also needs to be decarbonised. Therefore Hydrogen is reliant on the decarbonisation of natural gas and/or electricity generation if it is to contribute to the 2050 emissions target. For Methane to Natural Gas (i.e. SMR process) the carbon dioxide that remains will need to be stored in CCS storage facilities. For electrolysis electricity generation will need to be de-carbonised.

Small volumes of hydrogen (up to 10% v/v) can be blended with natural gas to produce a lower carbon fuel, however this only produces about a 3% reduction in carbon emissions. So for our study we have considered that areas that some areas are fully converted to pure hydrogen the rest remain using methane. We consider this to be a more efficient than converting more customers to run on a hydrogen blend where their appliances would still need to be upgraded anyway.

For this study, given the large amounts of electricity needed for the electrolysis hydrogen process we have looked at how hydrogen can be derived from gas using the steam methane reforming process as explored in Northern Gas Networks' H21 Leeds Citygate project. This is not to say production of hydrogen via electrolysis could not also play a role in any future where hydrogen is used.

Hydrogen can be blended with natural gas to produce a lower carbon fuel, however this may still require conversion of household appliances.

10.1.2 Biomethane, Biogas and Bio-SNG

'Biomethane' refers to a gas mixture that is predominantly methane (>97%) and is sourced from organic material (biomass). This gas has similar thermal characteristics to natural gas. Subject to meeting the gas quality requirements, bio-methane is considered as pipeline quality gas and can be injected into the natural gas network and used in existing gas appliances. Biomethane can be produced by processing Biogas or Bio-SNG.

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[38] HYDROGEN PRODUCTION: NATURAL GAS REFORMING, US Office and Energy efficiency & Renewable Energy http://energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming

[39] HYDROGEN PRODUCTION: ELECTROLYSIS, US Office and Energy efficiency & Renewable Energy

http://energy.gov/eere/fuelcells/hydrogen-production-electrolysis

'Biogas' is a term used to refer to a combustible gas created by anaerobic digestion of organic material. Anaerobic digestion is a natural biological process carried out by bacteria, in a humid environment in the absence of air, in which organic material is broken down into a stable fertiliser and useful biogas. Placing wet organic material in an airtight container can create this environment. These containers are known as Anaerobic Digesters (AD), and the biogas they generate can easily be captured. Biogas is also produced at landfill sites ("landfill gas") and sewage treatment works ("sewage gas").

'Bio-SNG' is a term used to refer to a combustible gas that has been created by the thermochemical process of gasification of organic material. The biomass is heated to a high temperature and the resulting gases undergo chemical reactions to form a synthesis gas. Bio-SNG predominantly comprises hydrogen (H2), carbon monoxide (CO), methane (CH4) and carbon dioxide (CO2) but the exact composition of the bio-SNG will depend on the technology and material being gasified. There are several gasification process designs, including fixed bed, fluidised bed, multi-stage, indirect and plasma technology. Gasification allows for recovery of gas from organic materials that cannot be readily processed by anaerobic digestion[40].

Biogas of suitable quality to be injected into the GB gas system still has a carbon footprint. See Appendix A for the CO2 values we have used for our scenarios.

10.1.3 **Shale gas**

Shale gas is natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich resources of petroleum and natural gas. Shale gas is extracted following two main steps[41]:

The progress made on extraction method of shale gas in recent decade has allowed access to large volumes of shale gas. This enables gas producers to extract shale gas at reasonable cost and allows commercial quantities to be produced from shale[42].

Shale gas has transformed the energy landscape in the US, however in GB it is not known how much recoverable shale gas there is. Further work is being carried out by the British Geological Survey (BGS)[43]. Shale gas has the potential to provide a large indigenous source of energy however there remains a great deal of uncertainty.

10.2 Carbon Capture and Storage

Carbon (CO2) Capture and Storage (CCS) is a process by which the CO2 produced in the combustion of fossil fuels is captured, transported to a storage location and isolated from the atmosphere. Capture of CO2 can be applied to large emission sources like power plants used for electricity generation and industrial processes. The CO2 is then compressed and transported for long-term storage in geological formations or for use in industrial processes.

Rather than being a single technology, CCS is a suite of technologies and processes. Some of these have been operated successfully for decades, however large-scale CCS for power generation has yet to take off in the UK[44].

CCS has an important role to play to ensure manufacturing industries continue to operate while substantially reducing emissions of greenhouse gas to the atmosphere. CCS can capture up to 90% of the carbon dioxide (CO2) emissions produced from the use of fossil fuels in electricity generation and industrial processes[45]. For our study we have assumed that CCS is used for the carbon derived from methane in the production of hydrogen.

Globally there are 15- large scale CCS projects in operation with a further seven under construction. The total CO2 capture capacity of these 22 projects is around 40 million tonnes per annum (Mtpa)[46].

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[40] Biomethane into the Gas network: A guide for producers

[41] British Geological Survey.

[42] Shale TEC.

[43] Shale Gas: British Geological Survey.

[44] Future of carbon capture and storage in the UK, House of Commons, Energy and Climate Change Committee.

[45] CCS Association.

[46] Large Scale CCS, CCS Projects, Global CCS institute

10.3 Substitute heating technologies

Heat networks

Heat networks provide a network of multiple buildings or sites with heat and hot water from a central source of production. The size of networks could vary from carrying heat just a few hundred metres between homes and flats, to several kilometres supplying entire communities and industrial areas. There are a number of different energy sources that can be used for district heating, including biomass, geothermal heat, energy from waste, solar systems, heat pumps, waste heat from industrial processes, in addition to conventional boilers and cogeneration[47]. Figure 2 provides a map of the district heating network in Nottingham which is the largest in the UK.

Heat networks currently provide around 2% of heat demand from buildings in the UK and are most effective in high-density regions[48]. DECC view heat networks as having the potential to be a cost-effective solution to decarbonising heat, "with the potential to supply between 14% and 43% of total UK heat demand from buildings (i.e. residential and commercial demand) by 2050"[49]. In practice increasing energy efficiency in buildings and the fall in the carbon footprint of electricity is making the case for heat networks more difficult. Real data from DECC indicates how difficult it is to achieve substantial carbon savings[50].

Biomass CHP

Biomass combined heat and power (CHP) is a combined heating and power systems for decentralised renewable energy. The heat generated can provide (up to 90ºC) hot water heating for heat networks[51].

In a district heat network, heat can be provided by a combination of technologies including CHPs, biomass boilers, gas boilers and heat pumps. Figure 3 outlines an example of the heat network powered by Bio-mass CHP.

A heat network system powered by Biomass CHP is currently used in Newcastle's Riverside Dene Estate[52]. The £1.7 million wood fuelled biomass community heating system provides low carbon heat and hot water to the entire Riverside Dene estate from one energy centre. The fuel handling system is consisted of a wood pellet fuel storage, with a piping system installed that allows the biomass fuel to be fed directly into the bunkers from the biomass delivery vans. The fuel handling system then conveys the wood pellets from the bunkers to the biomass boiler.

Any increase or decrease in demand for hot water and heating on the boiler automatically changes the speed that the wood chip fuel is supplied to the biomass boiler. Heating and hot water is distributed from the 'heat hub' to the buildings in the system through and underground pipe network. In addition, a peak demand gas boiler is used as backup. Customers have individual meters and heat-exchangers to transfer the heat to their central heating systems.

In addition, individual buildings can generate heat and electricity simultaneously by using a Micro-CHP. The main output of a micro-CHP system is heat, with some electricity generation. Micro-CHP systems are currently powered by gas or LPG but they may be powered by oil or bio-liquids in the future[53].

Bio-mass may not be a net benefit to decarbonisation. All of these biologically derived energy sources only reduce carbon emissions if the carbon atoms are from managed sustainable forests in appropriate geographical regions or from non-food competitive agriculture.

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[47] Local Government Association.

[48] DECC, Consultation on ensuring regulation encourages innovation (2016).

[49] DECC, Consultation on ensuring regulation encourages innovation (2016).

[50] Assessment of the Costs, Performance, and Characteristics of UK Heat Networks, DECC

[51] Combined heat and power (CHP), Biomass Energy Centre

[52] Newcastle City Council, Riverside Dene project, Vital Energi

[53] Micro CHP, Energy Savings Trust

Prosumer energy

A 'Prosumer' refers to energy customers with the ability to generate and store their own energy, for their own use and potentially to feed into the electricity grid. The cost of decentralised energy technologies is falling rapidly following recent technology innovation and production enhancements[54]. This has highlighted the potential benefits of prosumer energy, which is to help lower energy costs for consumers and contribute to decarbonisation[55].

A prosumer energy is not one type of system but rather a number of ways of generating and storing energy (electrical energy) at an individual building level. The types of technologies used (and their effectiveness) will depend on a number of factors including size of property, its use (i.e. a home or a commercial use building etc.) and whether it is new or old housing stock. The technologies used could include[56]:

- Building Integrated Photovoltaics (BIPV) applied to the roof sheeting to generate electricity
- A Solar Air Collector which draws warm air into the building to supply heat
- Electricity generated by the photovoltaics stored in batteries
- Warm air from the Solar Air Collector can be stored from day-to-night and summer-to-winter in a tank supplying the heating system.

These new technologies are being developed as coatings for building materials. Once developed, these products can be fitted to the roofs, walls and windows of new and existing buildings to generate, store and release renewable energy[57].

There remain however considerable practical barriers to overcome including the space that these technologies may take up (which are not available in a large number of properties) and the upfront costs which most consumers would struggle to afford.

Even if they are carbon neutral over the year (i.e. the property requires no net import of carbon), very many systems require significant quantities of imported energy in a cold January or February. Mechanisms to pay for this peak supply of fossil energy are currently ill-defined. To date nearly all of these prosumer systems have been taken up by enthusiastic early adopters. Many require the householder to be positively engaged with their heating systems and as we have already explored many sections of society just want reasonably priced energy 'on-tap'.

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[54] KPMG, Development of decentralised energy and storage systems in the UK (2016).

[55] KPMG, Development of decentralised energy and storage systems in the UK (2016).

[56] SPECIFIC.

[57] SPECIFIC.

10.4 Transport technologies

Although our study focuses on heat we have also considered the potential decarbonisation impact of road and rail and how this may interact with changes in the energy network. At a high level we have looked at alternatives to petrol as a fuel for vehicles.

Electric vehicles

Electric vehicles (EVs) are powered by a battery which is charged either at home or at charging points. EVs produce no emissions at the point of use, however they do draw from the electricity network which does produce carbon emissions.

EVs may be considered better suited to smaller vehicles, where power need is not so great and the battery can last longer and shorter journeys in urban environments where access to regular charging points is possible.

Using electric batteries as an energy source for cars has been around for as long as petrol cars, the main issue has been limited battery life and being able to charge the battery when away from an electricity source. A national electricity vehicle charging network has not emerged. Developments in electric battery technology has meant that the EVs are becoming a more viable option which means it is reasonable to assume that a lot more electric vehicles will be on the road in 2050.

Electric hybrid vehicles, while still using liquid fuel and therefore emitting carbon, emit a lot less carbon and could remain a part of the transport mix in 2050.

Electric rail is now widespread across the UK and the Government has committed to electrification of more lines[58]. Our assumption in this study is that the vast majority of rail lines are electrified by 2050.

Hydrogen fuel cell vehicles

The other transport technology that we have looked at is Hydrogen fuel cell vehicles. Similar to a battery-electric car, a fuel cell car dispenses with the internal combustion engine altogether. Fuel cells are electro-chemical devices that convert the energy stored in chemical form directly into electrical energy, water and heat[59]. Other fuels can be used but it is hydrogen that has developed the most as it is highly combustible with a high energy content.

Fuel cell vehicles offer significant advantages of range and longer refuelling time and therefore particularly well suited to vehicles travelling longer distances. Current take-up of hydrogen fuel cells is limited largely due to the lack of refuelling points and the vehicles themselves are relatively expensive[60]. This is a ‘chicken and egg’ situation as without hydrogen fuel vehicles in sufficient numbers a refuelling network is unlikely to develop.

There are three types of NGVs:

- Dedicated: These vehicles are designed to run only on natural gas.
- Bi-fuel: These vehicles have two separate fuelling systems that enable them to run on either natural gas or gasoline.
- Dual-fuel: These vehicles are traditionally limited to heavy-duty applications, have fuel systems that run on natural gas, and use diesel fuel for ignition assistance.

Light-duty vehicles are typically equipped with dedicated or bi-fuel systems, while heavy-duty vehicles use dedicated or dual-fuel systems. On the vehicle, natural gas is stored in tanks as CNG. LNG, a more expensive option, is used in some heavy-duty vehicles. The form of natural gas used is typically chosen based on the range an application needs. Because it is a liquid, the energy density of LNG is greater than CNG, so more fuel can be stored onboard the vehicle. This makes LNG well-suited for larger HGVs requiring a greater range.

Dedicated NGVs only have one fuel tank, so they aren't as heavy as bi-fuel NGVs and can offer more cargo capacity. The driving range of NGVs is generally less than that of comparable conventional vehicles because of

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[58] Electrification: Future plans, Network Rail

[59] Hydrogen Fuel cell cars, Next green car

[60] Fuelling Britain’s Future: A report for the European Climate Foundation, Cambridge econometrics

the lower energy density of natural gas. Extra storage tanks can increase range, but the additional weight may displace cargo capacity[61].

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[61] Natural Gas Vehicles, US Department of Energy Alternative Fuels data centre

11 Appendix B: Costing our Scenarios

Our starting point

There are two broad types of energy demand on the grid: power and heat. In this study we define heat demand as space heating (i.e. heating rooms), hot water and cooking. We define power demand as the demand for various electrical appliances that are not heat related: lighting, televisions, washing machines etc. In GB heat demand is approximately two thirds of residential and commercial demand, power demand being the other third. Currently natural gas (methane) transported through the gas networks provides the majority of the energy for heating. Electric heating, district heating schemes and oil (petrol and diesel) provide the remainder.

This study focuses on decarbonisation of heat at a residential and commercial level. We assume that the split between power and heat demand will remain broadly the same. Therefore the question we are seeking to address in this report is how heat can be decarbonised.

Although our primary focus is on heat we have also examined the impact of decarbonisation of surface transport, which we define as Road and Rail transport (aviation and shipping are not included in this study). Any plan to reduce carbon emissions will need to include a reduction of the emissions of one or both of these sectors.

How we developed our scenarios

The aim of this study is to examine ways that this decarbonisation of heat and transport could happen. We found that the best way of looking at potential options was to develop individual scenarios or 'snapshots' of a possible future in 2050. Each snapshot shows at a high level how people heat and power their homes and businesses and how they move from A to B. Each scenario is technologically feasible (with some testing required), and could, with the will and investment, start to be implemented today.

The purpose of having these scenarios is to show a range of possibilities. To this end we have deliberately chosen contrasting possibilities. To develop our scenarios we considered two key variables:

- How much will gas continue to be used as a final source for consumers?
- Whether decisions about future energy use be taken locally or nationally (or both).

Scenario 1 - Evolution of Gas: is a future where most customers remain connected to the national gas network but this network evolves to transport alternative gas (Hydrogen) in some areas.

Scenario 2 - Prosumers: is a future where some residential and commercial properties are no longer connected to the gas network. Instead there is more individual control over energy with many customers installing self-generation and small scale storage technologies to provide much of their own energy needs.

Scenario 3 - Diversified Energy Mix: In this scenario each local area has its own energy delivery method. Gas (either methane or Hydrogen) is still used in some areas. In urban areas heat networks are used and in some areas heating is electrified.

Scenario 4 - Electric Future: In this scenario there is a complete national conversion of residential and commercial heating and cooking to electricity transported via the national grid.

Central Demand assumptions

In our study we have set out to show different ways of delivering energy in 2050. To keep things simple and ensure we are comparing like with like, we have used one overall forecast of energy demand for all four scenarios. We have used the National Grid's Future Energy Scenarios (FES)[62]. We assume in our model that the carbon target will be met in 2050. Therefore we have chosen the Gone Green scenario in FES 2015, the only scenario to achieve all renewables and carbon targets on time, as our baseline scenario. We use the Gone Green figures without any adjustments for electricity consumption, peak electricity demand and gas consumption by all sectors other than residential and commercial. For residential and commercial gas consumption and gas peak demand, we add 15% onto the FES forecast figures for 2050 (after extrapolating to that year) because we believe that household efficiency projections were too optimistic in the FES. We increase

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[62] National Grid, Future Energy Scenarios 2015.

the FES figures incrementally above their original values year by year until they are 15% above the original value in 2050.

In our cost calculations, the final consumption demand inputs are derived from the total annual energy demand in the Gone Green scenario, adjusted as described. We assume that the Gone Green's energy demand profile (2014 – 2035) will follow the same trend until 2050. Under this assumption, we obtain our final consumption demand by extending the Gone Green's demand profile to 2050.

The final consumption demand (measured in TWh) is broken down into:

- Type of energy source – gas (natural gas, biomethane, hydrogen), heat networks or electricity.
- Type of use - residential and commercial (heat and power), industrial and transport (road & rail)

Peak power demand

Peak demand (measured in GW) is sourced from the Gone Green's peak demand of gas and electricity. The peak demand profile is extended to 2050 for the purpose of our analysis. For our modelling purposes we increase the FES peak gas demand figures by 15%, as per overall demand.

The peak demand figure for gas in the FES is the 1-in-20 peak day demand. National Grid define this as the level of winter demand that would only be exceeded once every twenty years, assuming that connected load is held at levels that would be expected given the weather conditions of the winter in question.

The peak demand figure for electricity is the maximum instantaneous power demand on the network in a given year. It usually occurs at around 5.30pm on a week-day in winter.

For our model we obtain the total peak power demand figures by summing the data series for peak electricity demand and peak gas demand. This relies on an implicit assumption that the peak demand for gas and electricity occurs at the same time.

Assumptions for power, industry and other sectors

Our scenarios look at different ways of supplying heat and surface transport. We have not examined any differences in other sectors. For our cost modelling we have assumed that other sectors that draw energy from the gas or electricity grid including heavy industrial usage will have the same fuel mix (either natural gas or electricity) as they do today. This includes the potential for biogas to be used as a substitute for natural gas. We have assumed that gas fired power generation will be used at the same level as it is today.

To ensure our study is as simple and focused as possible we have assumed that by 2050, outside of gas fired generation, all other electricity generation is decarbonised. Therefore any increase in electricity demand will need to be met by renewable and/or nuclear sources. This is a broad assumption we have made; we have not sought to assess how this may happen.

However, for the all-electric and prosumer scenarios, significant additional amounts of additional electricity is required with much of this sourced from intermittent renewables, especially solar that is unlikely to contribute to winter heating peaks. As such, we have assumed that a significant further proportion of flexible generation capacity will be needed as back up in these scenarios and have including this in our analysis.

We have assumed that the other sectors continue to use the same sources of energy as today and they are therefore not included in our study other than to work out the net carbon target.

See Appendix C for the full list of assumptions we have made.

Carbon allowance

We designed our scenarios so that in each scenario 2050 CO2 emissions[63] are a maximum of 20% of 1990 levels, thereby meeting the UK's 2050 carbon emissions target. Our aim was to design scenarios that met but did not 'overshoot' the 20% target (i.e. reduce carbon by more than the target requires).

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[63] Department for Energy and Climate Change, Updated Energy and Emissions Projections

We have only looked at two sectors: heating (space heating, hot water and cooking) and surface transport (road and rail), and therefore these are the only sectors which vary for each of our scenarios. We have assumed that emissions from other sectors are the same as the DECC Energy and Emissions Projections[64].

To work out how much carbon we needed to reduce from our two sectors, we worked out a carbon allowance, where the emissions from other sectors was subtracted from the overall CO2 emissions target.

	MtCO2e
Total CO2 emission allowance in 2050 for GB[65]	115
CO2 generated from the economy outside of our analysis	50
CO2 from Industrial and Electricity Generation – Gas	27
Remaining CO2 that can be used in heating and surface transport	38

Each of our scenarios can therefore only emit a maximum of 38 MTCO2e from either heating or road and rail (i.e. surface transport).

The DECC Energy and Emissions Projections exclude emissions from international aviation and shipping and emissions of greenhouse gases other than CO2. In our study we have only looked at CO2 emissions as this is the only emissions from gas.

By using the figure for CO2 emissions in 1990 rather than total greenhouse gas emissions, we are assuming that greenhouse gases will be emitted in the same proportions in 2050 as they were in 1990.

Assumptions behind the energy consumption data

Total energy consumption and energy consumption by sector are assumed to be the same for each scenario. For our model we use the energy consumption figures forecast by National Grid in the Future Energy Scenarios 2015 (FES), with the adjustments to residential and commercial gas consumption described in the section above. We use the demand figures from the Gone Green scenario as this is the only one of the four scenarios in the FES which meets the UK carbon emissions targets. We use demand figures from the FES wherever possible in order to maintain consistency.

The total energy demand figures in the FES are the sum of the demand for energy from gas and electricity for the residential, commercial, industrial, power generation and transport sectors. As such, they exclude the energy demanded for transport powered by petroleum fuels. We therefore use the FES figures for every component of demand other than transport.

We use the transport sector energy demand figures from the Department of Energy and Climate Change Publication: Updated Energy and Emissions Projections: 2015 (UEEP). We take total transport sector energy demand and transport energy demand by fuel type from this source.

Our figures for total energy demand are obtained by summing the energy demand from every sector other than transport as forecast in the FES Gone Green scenario with the transport sector energy demand as forecast in the UEEP.

Assumptions behind the FES energy demand figures

The FES forecasts rely on assumptions of future population and housing numbers. For these National Grid use economic and demographic projections by Experian Business Strategies. They assume that by 2035, the population of Great Britain will be 71 million and the number of homes will be 32 million.

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[64] As this only goes out to 2035 we have assumed a flat projection up until 2050.

[65] This figure already excludes international aviation and shipping as DECC exclude these sectors from their figures. We have also made an adjustment for Northern Ireland by making a reduction of 4% as this the current contribution of Northern Ireland to emissions figures and we assume that this remains constant.

Due to advances in energy efficient building design there is a difference in the energy demanded by a new build home compared to an existing home. In the FES the National Grid assume that building regulations are adjusted every four years, creating a step change reduction in the heat demanded by a new home each time. In the Gone Green scenario, all new homes build from 2020 onwards are assumed to be built to the Zero Carbon Homes standard[66].

The assumptions behind the forecast demand data in the FES for each sector feed through into the forecast total energy demand. For the Gone Green scenario National Grid assume that demand from the residential sector tends to decrease over the forecast period because of the electrification of heating, increased efficiency of domestic appliances and improved insulation. Industrial energy demand is forecast to decline as industry itself declines, while commercial demand is forecast to remain flat.

Industrial demand, gas exports and power station demand all feature in our model under the categories labelled "other"; that is, other gas or other electricity.

Industrial demand for energy from both gas and electricity is forecast to decline in the Gone Green scenario because of the shift within that sector away from more polluting activities, such as textiles, towards less polluting activities like pharmaceuticals.

A significant rise in demand for gas for exports is projected in the Gone Green scenario. Gas exports from Great Britain flow to Ireland and Continental Europe. National Grid assume that exports to Ireland will increase over the forecast period as the capacity of indigenous Irish supplies falls. Exports to Europe are also assumed to increase over the period, with the higher economic growth assumed in the Gone Green scenario leading to increased gas demand in Europe.

Demand for gas for electricity generation is forecast to fall in the Gone Green scenario as renewable generation technologies take the place of gas power.

Assumptions and calculations behind the transport sector energy demand figures

We use the transport sector demand figures from the reference scenario of the UEEP forecasts. The figures in the reference scenario are based on central estimates of economic growth and fossil fuel prices. They take into account all agreed policies where the policy design is sufficiently advanced to allow robust estimates of impact. The figures therefore take into account planned policies. The UEEP forecasts predict a decline in transport sector energy demand as a result of increased vehicle efficiency.

The UEEP figures are for the UK, while our model is focused on the energy network of Great Britain. We assume that Northern Ireland accounts for 3% of demand for each fuel type component of transport demand. We therefore take 97% of the UEEP figures to represent transport demand in GB.

This assumption is based on the fact that Northern Ireland accounts for 3% of consumption of petroleum for road transport in the UK, according to figures published by DECC in the data set entitled Road transport energy consumption at regional and local authority level[67]. We assume that Northern Ireland accounts for the same percentage of UK transport demand for all fuel types.

Network Cost calculations

Our study looks at the costs of reinforcing the electricity distribution network at a high level. To avoid complexity we have not attempted a bottom-up approach to costs looking at the individual cost of assets. Rather we have taken a top down approach to give us the cost per GW of reinforcing the network and connections. Our cost per GW figure is made up of two cost areas:

- A calculation of network costs per GW using Regulated Asset Value (RAV); and
- A calculation of the cost of reinforcing connections based on industry connection costs.

a. Network costs per additional GW

We have taken the combined Regulated Asset Values (RAV) for each distribution company for 2023 (the last year of current price control) from Ofgem's RIIO-ED1 Price Control Financial Model (PCFM).[68]

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[66] Zero Carbon Hub.

[67] https://www.gov.uk/government/statistical-data-sets/road-transport-energy-consumption-at-regional-and-local-authority-level

[68] Ofgem, Price Control Financial Model.

We then divide this combined RAV figure by the peak electricity demand in 2023 according to National Grid Scenarios FES2015 Gone Green scenario forecast.[69] This gives us a figure per GW. (We also do the same calculation for the transmission network)

Peak in 2023 (GW)	RAV in 2023 (£ million, 2015 prices)	Network cost in 2023 (£ million per GW)
62	17562	285

b. Connection reinforcement costs

Property Type	Cost per property (low estimate)
Domestic	£750
Commercial	£6000

We estimated connection reinforcement costs for Residential and Commercial properties informed by industry connection costs (from DNOs and iDNOS). We have taken a conservative approach and used figures at the lower end of the scale, reflecting the fact that not all customers will need a completely new connection.

We have then multiplied these reinforcement costs by the total number of residential and commercial properties in GB respectively. We then divide this number by the current peak electricity demand according to FES2015 (80 GW). This gives us a figure of **£300m/GW**.

	Number of gas connections (million)	Costs (£ million)
Domestic	23	17,250
Commercial	1.2	6,960
Total		**26,460**

Finally, we add our figures for network cost and connection cost together to give us a total high level cost of **£585m/GW**.

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[69] National Grid, Future Energy Scenarios 2015.

12 Appendix C: Assumptions table

Consumption

Model Ref	Assumption	How we have calculated
1	Total demand (excluding transport)	— Used projections from the National Grid, Future Energy Scenarios 2015 (FES2015). — Used the Gone Green scenario as it meets the 2050 carbon target. — However we reduced the impact of household efficiency in the gas consumption projections by 15% as we judged that the gone green projections were too optimistic this raises the overall demand slightly — Extrapolated the FES2015 projections to 2050. — Excluded any use of gas or electricity for transport as we used DECC UEEP figures (see below)
2	Transport consumption	— Used Department of Energy and Climate Change, Updated Energy and Emissions Projections: 2015 (UEEP), Reference scenario as these are central estimates. — Extrapolated the UEEP projections to 2050. — Assumed that Northern Ireland will continue to account for 3% of transport consumption demand and therefore subtracted 3% from our figures.
3	Prices of the commodities - Electricity prices	— Used the base case of the GB baseload electricity prices from FES2015 — Used this data to calculate commodity cost of electricity including cost of building new capacity. — Assumed that coal fired power stations are closed to adhere to the Industrial Emissions Directive (IED). — Therefore we assumed that gas is the only carbon emitting electricity source with renewables and nuclear making up the rest. — We recognise that prediction of commodity figures is a difficult task and subject to large fluctuations; and that the FES 2015 may be outdated. However, our scenarios are compared to a control scenario in which the same commodity figures are used. Therefore the impact of using different commodity figures is likely to be small.
5	Prices of the commodities - Gas prices	— Used wholesale NBP gas price base case from FES2015. — Used this data to calculate commodity cost of gas including cost of sourcing gas. — Assumed that any biogas is sold into market at the same price as natural gas.
6	Prices of the commodities - Conversion factor: 1 Therm to MWh 0.029 MWh/therm	— Figure given by Department for Environment Food & Rural Affairs (DEFRA), Greenhouse Gas Conversion Factor Repository 2015. — Used to convert price data given in the FES2015 in units of pence/therm to units of £/MWh.

7	Peak demand	— Used the Gone Green projections from the FES2015 and added gas and electricity together. — However we have reduced the savings from efficiency that were in Gone Green 15%, as we judged that household efficiency projections were too optimistic. — Did not include demand from road or rail transport as we assumed that gas vehicles are supplied separately from the grid and that electric vehicles are charged during off-peak hours.
8	Peak residential and commercial demand	— To calculate peak demand for residential and commercial we assumed that the average hourly energy consumption of non-domestic customers is constant in relation to total demand. — We subtracted this from the total peak demand figure in FES2015 to give residential and commercial peak demand.

Emissions

Model Ref	Assumption	How we have calculated
9	Carbon emissions from Natural gas 0.184 CO2e/KWh	— Used Department for Environment Food & Rural Affairs (DEFRA), Greenhouse Gas Conversion Factor Repository 2015.
10	Carbon emissions from Biomethane 0.06873 kgCO2e/KWh	— We have used the average from: – DEFRA Scope 1 (tank to wheel or combustion emissions) and the Scope 3 (well to tank to fuel production emissions) for biogas = 0.03946 kgCO2e/kwh; and – The Government's Standard Assessment Procedure for Energy rating of Dwellings, SAP 2012 (p 225) = 0.098kgCo2e/KWh
11	Carbon emissions for the blended gas at distribution level in 2050 Scenario 1: 0.149468 kgCO2e/KWh Scenario 3: 0.1264 kgCO2e/KWh	— In our scenarios where gas is being injected into the distribution network we assume that a blended of CO2e/KWh for gas used at a distribution level — This varies by scenario as we assume the proportion of biomethane to natural gas is different — Note that scenarios 2 & 4 assume no gas is used at residential and commercial level in 2050.
11	Carbon emissions from petrol 0.239 MtCO2/TWh	— Used Department for Environment Food & Rural Affairs (DEFRA), Greenhouse Gas Conversion Factor Repository 2015. — Only used figures for petrol as we assumed that diesel and other fuels are phased out.

11	Carbon emissions from grid hydrogen 0.0184 MtCO2/TWh (= 10% * carbon emissions from gas)	— Used Department for Environment Food & Rural Affairs (DEFRA), Greenhouse Gas Conversion Factor Repository 2015. — Our assumption is that the steam methane reformer process that produces hydrogen from methane removes 90% of the carbon from methane. — We assumed that hydrogen fuel cells for vehicles emit no carbon as they extract energy from hydrogen in a reaction that does not produce carbon.
12	Carbon generated outside of our analysis 50 MtCO2	— Subtracted the CO2 generated in sectors not considered in our model from the 2050 emissions target using figures from the Department of Energy and Climate Change, Updated Energy and Emissions Projections: 2015 (UEEP) (Reference scenario). — These sectors are: industrial processes, off road construction, industrial combustion for energy generation other than that entering the network, refineries, land use, land use change and forestry, agriculture, forestry fuel and domestic aviation and shipping. — We used the 2035 figures because this is the last year of the DECC projections. We assumed that emission by these sectors remains constant from 2035 – 2050. — International aviation and shipping is not subtracted here as it is excluded from the original figure for the 2050 target.
13	Rate of energy conversion from natural gas (methane) to hydrogen 68.5%	— This is a Kiwa estimate and includes all of the energy required to operate the steam methane reformer (SMR) facility, including compressors, thermal efficiency losses and the removal of CO2 to be stored. — Used this to determine the amount of natural gas required to produce hydrogen that will be transported through the distribution grid when that hydrogen is produced using steam methane reforming facilities.

Costs

Model Ref	Assumption	How we have calculated
14	Per GW cost of new electricity transmission network capacity High case: £271m/GW Low case: £221m/GW	— Took the combined Regulated Asset Values (RAV) for each Transmission company for 2021 (last year of current price control) of Ofgem, RIIO-ET1 Price Controls Financial Model (PCFM). — Divided this RAV by the peak electricity demand in 2021 according to the FES2015 Gone Green scenario forecast. — Use this per GW figure to show costs of incremental investment in transmission network in each scenario.
15	Per GW Cost of new electricity transmission level storage High case: £1,275m/GW Low case: £850m/GW (with declining cost profile)	— This figure is the capex cost per unit of power capacity of a grid scale lithium ion battery storage system taken from a KPMG report 'Development of decentralised energy and storage systems in the UK' (page 43) — Used the range of costs in the report. We then assumed that the cost declines linearly until it is reduced by 15% in 2050, in line with the projections set out in the report.

16	Per GW cost of new electricity distribution network capacity High case: £646m/GW Low case: £529m/GW	— This is the sum of **a)** the incremental cost of reinforcing the electricity distribution network and **b)** the cost of reinforcing connections to properties. — **For a)** we took the combined Regulated Asset Values (RAV) for each distribution company for 2023 (the last year of current price control) from Ofgem's RIIO-ED1 Price Control Financial Model (PCFM). — Divided this RAV by the peak electricity demand in 2023 according to the FES2015 Gone Green scenario forecast to give per GW figure. — **For b)** we estimated connection reinforcement costs for residential and commercial properties informed by connection cost information published by Northern Power Grid and UKPN. We took a conservative approach and used figures at the lower end. — We multiplied these reinforcement costs by the total number of residential and commercial properties in GB respectively. — We divided this number by the peak electricity demand in 2014. This gives a cost per GW of peak of reinforcing connections.
17	Per GW cost of new electricity distribution level storage High case: £1,831m/GW Low case: £1,220m/GW (declining costs)	— Multiplied the cost of transmission network scale storage in each year by the ratio of the cost of distribution scale solar PV systems to that of transmission scale solar PV systems using KPMG research for the report 'Development of decentralised energy and storage systems in the UK' — Our assumption is that the economies of scale factors for solar PV and storage are the same. — Used the range set out in the report. We then assumed that the cost declines linearly until it is reduced by 15% in 2050, in line with the projections set out in the report.
18	Cost of balancing the system for increased renewable generation £300m/GW	— Cost of incremental electricity needed will be largely renewable much of which will be intermittent — We have assumed that to ensure secruity of supply at peak times additional gas CCGT plants will be required, DECC figures show the capital costs as £600m per/GW. DECC CCGT capital costs — We have made an assumption that for every 2GW of additional electricity the system will need an additional GW of capacity from a flexible source (i.e. gas power plants) — Note that we have not assumed an increase in overall gas to power consumption, merely that at peak and/or when renewables are not generating more gas will be used and less gas at other times.
18	Cost of decommissioning the gas distribution network High case: £8,800m Low case: £7,200m	— Estimated cost of decommissioning the distribution networks according to National Grid. Our high case and low case figures are 10% more and less than National Grid's figure — In scenarios where gas is no longer used the cost of decommissioning part of the network is calculated as the fraction of this overall decommissioning cost.
19	Cost of constructing natural gas to hydrogen steam methane reformer (SMR) facilities High case: £1,260m/GW Low case: £1,540m/GW	— This figure is from research by Kiwa. It encompasses the full costs, including the costs of transporting the CO2 produced by SMR facilities to storage facilities. — This is used as the cost of producing hydrogen for use as a heating and cooking fuel in properties. (It does not include hydrogen for transport.)

20	Appliance change costs – natural gas to electricity High case: £12,000 per property Low case: £10,000 per property	— We have taken the range of the estimated cost of a typical Air Source Heat Pump, which is an electricity powered heating appliance taken from Energy Saving Trust (under subtitle: Heat), — We have added a further £3K of costs to account for other equipment including a hot water tank.
21	Appliance change costs – natural gas to hydrogen High case: £5,500 per property Low case: £4,500 per property	— A Kiwa/KPMG estimate of the average total cost of converting appliances to run off hydrogen instead of natural gas. — Added to the cost of converting local networks.
22	Appliance change costs - natural gas to heat network High case: £3,300 per property Low case: £2,700 per property	— The midpoint figure used is the average cost of a boiler compatible with a heat network according to DECC, Assessment of the Costs, Performance, and Characteristics of UK Heat Networks (page 35) — Figures inflated to better reflect financing and replacement costs.
23	Heat networks cost per property High case: £7,059 per property Low case: £5,218 per property	— This is the estimated cost per household of building a heat network (as opposed to the cost of converting equipment within homes) according to the WWU study on the energy trilemma. We have adjusted this figure downwards to take into account household conversion costs above.
24	Biomass plant cost High case: £3,960m/GW Low case: £3,240m/GW	— We used this figure as part of the total cost of heat networks as we made the assumption that the heat is provided from local small scale biomass sources. — Therefore we have used the costs of the smaller scale bio-mass plant (5-50MW) from DECC, Electricity Generation costs 2013 (p51 – 61).
25	Prosumer conversion Household High Case: £30,000 per household Low case: £27,500 per household Commercial High case: £100,000 per commercial property Low case: £90,000 per commercial property	— The average estimated costs of installing self-generation technology and converting appliances to use this electrical energy. — This is a KPMG and Kiwa estimate based on the average cost of these technologies and discussions with market providers. — We assumed that converted properties consume far less energy from the grid.

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