NAVIGANT

Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain

Prepared for:

Energy Networks Association

Submitted by:
Navigant Europe Ltd.
5th Floor, Woolgate Exchange
25 Basinghall Street
London EC2V 5HA

+44 20 3880 0800
navigant.com

Reference No.: 207594
21 October 2019

TABLE OF CONTENTS

EXECUTIVE SUMMARY

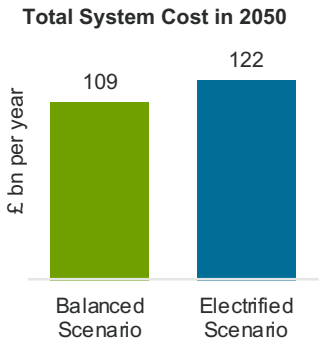
Natural gas plays a central role in the UK energy system today, but it is also a significant source of greenhouse gas (GHG) emissions. The UK committed in 2008 to reduce GHG emissions by at least 80%, compared to 1990 levels, by 2050. In June 2019, a more ambitious target was adopted into law and the UK became the first major economy to commit to "net-zero" emissions by 2050.

In this context, the Energy Networks Association (ENA) commissioned Navigant to explore the role that the gas sector can play in the decarbonisation of the Great Britain (GB) energy system. In this report, we demonstrate that low carbon and renewable gases can make a fundamental contribution to the decarbonisation pathway between now and 2050.

A balanced combination of low carbon gases and electricity is the optimal way to decarbonise the GB energy system and reach net-zero emissions by 2050

We developed scenarios to assess the cost-optimal way to decarbonise the 2050 GB energy system:

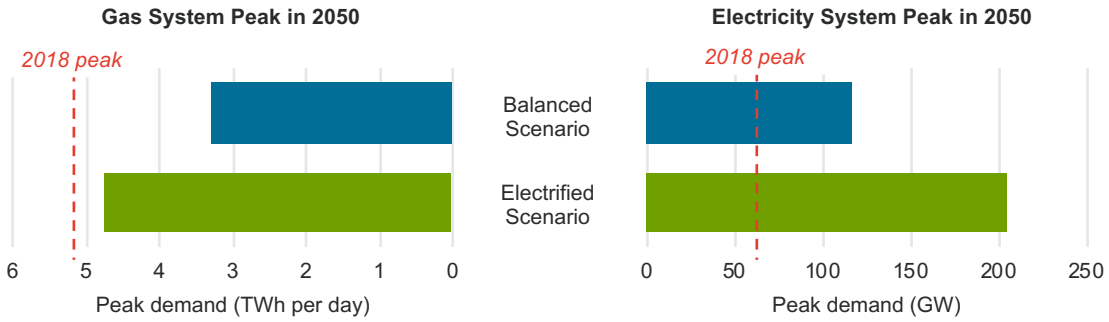
- A **Balanced Scenario** in which low carbon and renewable gases are used in a balanced combination with low carbon electricity
- An **Electrified Scenario** in which low carbon and renewable gas use is limited to cases where no reasonable alternative energy source exists, such as in certain industrial processes and transport modes and for dispatchable power generation



In a net-zero system, some GHG emissions will occur but they can be offset by "negative emissions" derived from biomethane or biomass use in combination with carbon capture and storage. While both scenarios achieve net-zero emissions, the Balanced Scenario does so at lower cost.

In both scenarios, the 2050 gas system peak is anticipated to be lower than today's. By contrast, both scenarios require a major build-out of power generation capacity and grid reinforcement; in particular, the Electrified Scenario 2050 electricity system peak is almost double that of the Balanced Scenario.

Gas networks already have the capacity to manage seasonal energy demand and three times the current electricity peak demand, contributing to system resilience and energy security



To reach a balanced, net-zero energy system in GB, the way we produce, supply and consume energy will need to change. A Pathway for the transition, focusing on how the gas sector can contribute step-by-step between now and 2050, is summarised on the next page. The Pathway is not a forecast, but it is relevant even if the GB energy system in 2050 looks slightly different than our Balanced Scenario.

Pathway to 2050

How the gas sector can contribute step-by-step to the decarbonisation of Great Britain's energy system

NAVIGANT ena energy networks association

1 Preparing for Transition

Strategic, technical and policy planning to enable low carbon gases to play a significant role in GB's transition to net-zero, while maintaining safe and reliable operation

- Update Gas Safety (Management) Regulations and Calculation of Thermal Energy Regulations
- Conduct trials and certification of key technologies
- Develop commercial models and funding mechanisms
- Develop skills and labour capacity
- Raise awareness of the transition to net-zero

2 Facilitating Connections

More anaerobic digestion (AD) biomethane plants connected to the gas grid
Preparations accelerate for first hydrogen projects
Ramp up energy efficiency improvements throughout GB

- Conduct joint network planning for GB gas grid infrastructure needs
- Standardise connection requirements for low carbon gas production
- Implement grid capacity solutions to facilitate AD biomethane injection
- Reduce fugitive methane emissions
- Deploy energy efficiency improvements (e.g. insulation and hybrid heat systems)

3 Expanding Supply

First hydrogen projects integrated with carbon capture, utilisation & storage (CCUS) and anchored by baseload consumers, likely from industry and transport.
Continuing scale-up of biomethane supply

- Establish first hydrogen projects with CCUS to supply baseload consumers
- Deploy small-scale hydrogen storage to manage peaks
- Roll out hydrogen-ready appliances to prepare for cluster development
- Increase AD biomethane supply
- Demonstrate bio-SNG production technology

4 Expanding the Demand Base

Hydrogen use extends to commercial and residential consumers near the first hydrogen projects, initially via low blends (up to 20%) but developing into 100% hydrogen clusters
Consumers in other regions continue to receive natural gas, with rising blends of biomethane

- Implement programme to switch more consumers to hydrogen
- Use hydrogen blending for flexible network management
- Deploy large-scale hydrogen storage to manage peaks
- Increase biomethane supply including via bio-SNG
- Continue improving energy efficiency throughout GB

5 Increasing Low Carbon Gases

Hydrogen clusters spread and connect to become extensive hydrogen zones, enabled by an evolving, carefully managed National Transmission System (NTS)
Greater volumes and diversification of low carbon gas supply as more production methods mature technically and economically

- Expand supply and demand to form larger hydrogen zones and biomethane zones
- Increase green hydrogen supply via electrolysis using renewable power
- Maintain biomethane availability at transport hubs all over GB, including within hydrogen zones
- Continue joint network planning to manage the transition, including reconfiguring the NTS

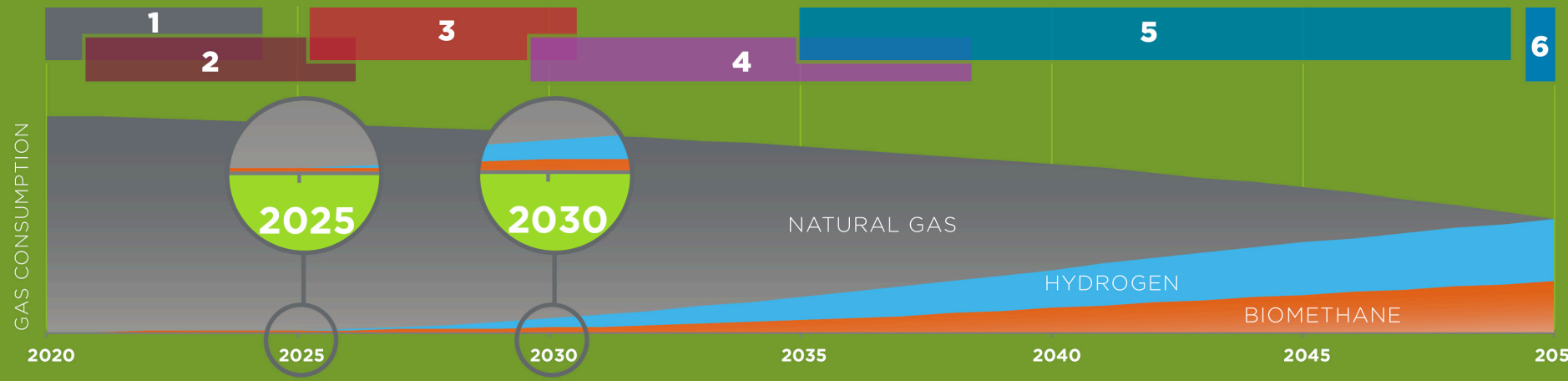
6 100% Low Carbon Gases

Low carbon gases fully integrated across the GB energy system, with distinct regional solutions

All gas end-users are supplied with hydrogen and/or biomethane, the principal type varying by region

Natural gas no longer used, unless abated with CCUS for blue hydrogen production

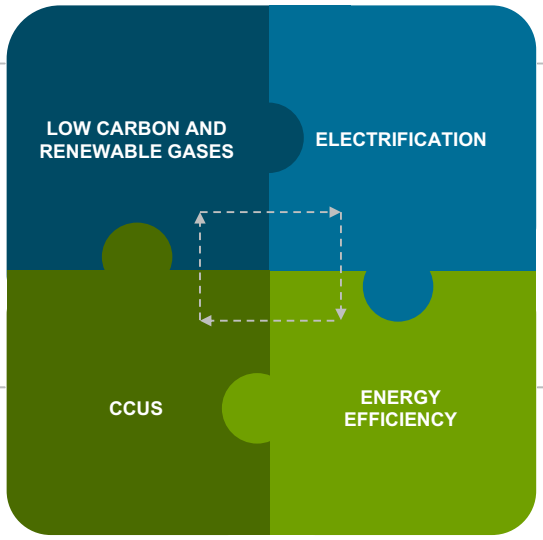
Net-zero energy system achieved in 2050



The Pathway is built around four core elements, which work together to reduce the overall cost and disruption of decarbonising the energy system.

LOW CARBON AND RENEWABLE GASES
will be fully integrated into the GB energy system. By 2050, all gas end-users will be supplied with hydrogen and/or biomethane. Hydrogen will be produced by natural gas reforming, creating the basis for hydrogen clusters, and by electrolysis using renewable power (both dedicated and curtailed generation). Biomethane will be produced by anaerobic digestion and thermal gasification.

CARBON CAPTURE, UTILISATION AND STORAGE (CCUS)
will be needed to reduce emissions from hydrogen production and industrial processes. It will also provide "negative emissions" when combined with certain bio-energy technologies.



ELECTRIFICATION
will occur across the demand sectors. Most road transport will be electrified, as well as short-distance shipping. There will be electrification of low-temperature industrial processes. According to our analysis, hybrid heat systems – an electric heat pump paired with a low carbon or renewable gas boiler – will be a key technology for decarbonising the buildings sector in a cost-optimal way.

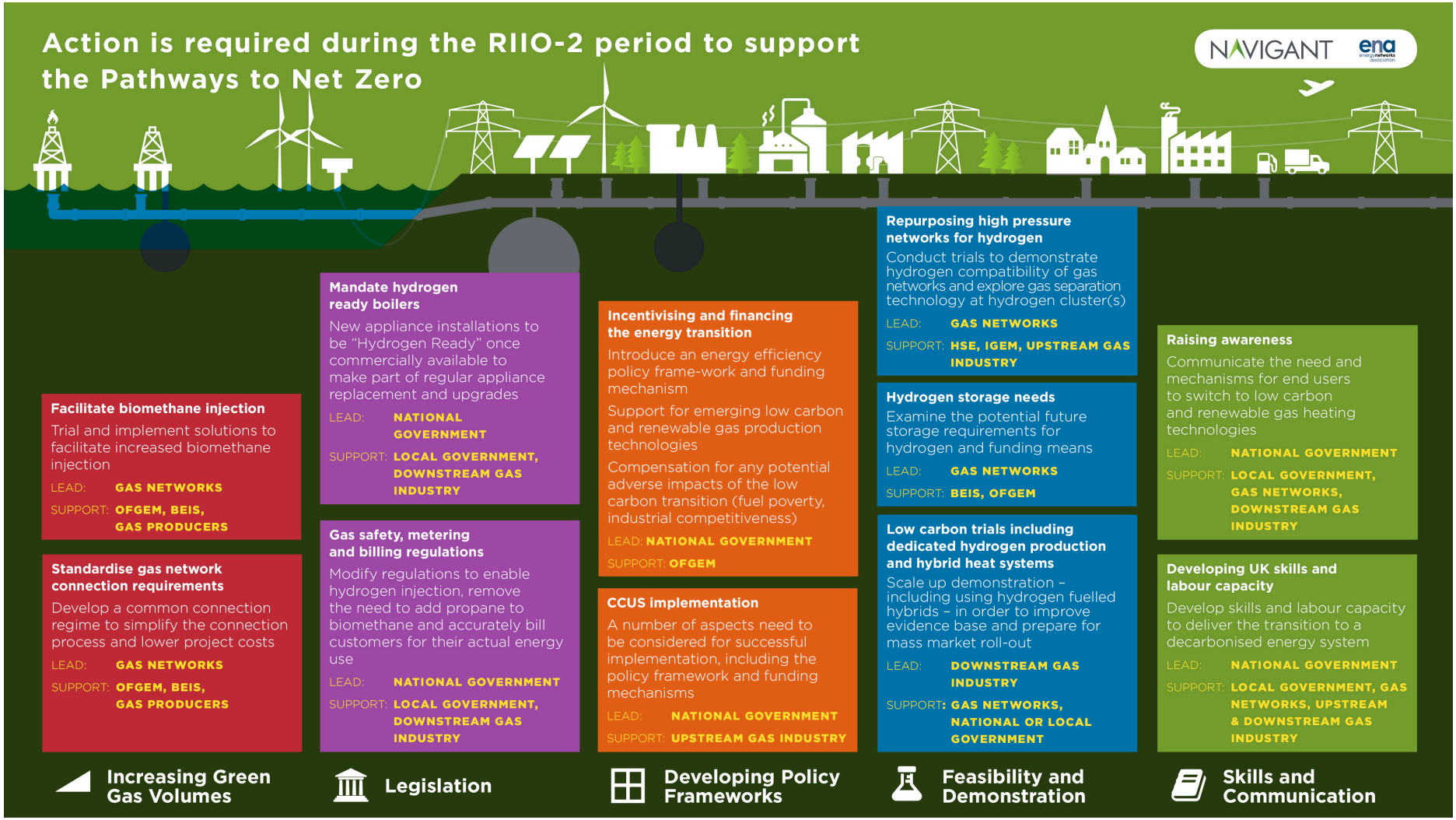
ENERGY EFFICIENCY
will need to improve across GB, particularly in the buildings sector as a complement to electrification. Renovation measures such as loft insulation and high-performance glazing will be deployed to bring the majority of buildings up to a moderate level of energy efficiency.

Each of these elements comes with challenges and uncertainties which may affect the delivery of the Pathway. Some are highlighted below.

Challenge	Mitigation
Net-zero emissions cannot be achieved if the commercial viability of CCUS is delayed	Establish a stable regulatory framework and support mechanisms as soon as possible to enable commercial CCUS deployment
First hydrogen projects are difficult to develop without industrial baseload demand	Support industry adoption of hydrogen through financial incentives and research & development to enable process conversion and to reduce hydrogen production costs
Renovation of the building stock may be constrained by supply chain, skills and labour capacity	Establish policies to boost deployment capacity. Net-zero can still be reached if a lower proportion of buildings is renovated by 2050, but overall system cost will be higher
End-users may not fully embrace high-efficiency heating systems and insulation in buildings	Develop incentives and funding mechanisms to encourage uptake. Net-zero can still be reached if most buildings retain standalone gas boilers, but overall system cost will be higher

The transition of the whole GB energy system to net-zero must be underpinned by coordinated policy and regulatory support

A critical factor for a successful transition as described in the Pathway is the initial strategic, technical and policy planning to enable low carbon and renewable gases to play a significant role. Policy support must also link up with regulatory expectations to enable appropriate incentives for effective business planning and investment decisions under RIIO-2. These foundational steps, along with other recommendations for near-term, low-regret actions, are presented on the following page.



1. INTRODUCTION

1.1 Role of Gas Today

Natural gas plays a central role in the UK energy system today. In 2018, natural gas accounted for 39% (880 TWh) of primary energy demand. UK gas demand is dominated by two sectors: domestic consumption and power generation, which together make up about 70% of demand; the remainder goes to industrial, commercial and other uses.[1]

Importantly, gas is used to generate about 40% of UK electricity, a rising trend since 2015. With the decline in output from coal-fired power plants, it performs a key role in providing energy security for the UK and continuity of energy supply for the domestic sector.

UK energy demand is highly seasonal, driven primarily by the need for heating in winter. Gas satisfies most of the seasonal peak demand, providing six times more energy than electricity and in 2017 nearly two-thirds of domestic energy demand. The entire gas supply chain from production, storage and import capacity, through to the design and operation of the gas networks is set up to reliably meet the winter peak energy demand.

1.2 Climate Change Context

The Climate Change Act 2008 forms the legal basis for the UK's approach to dealing with climate change. The Act also established the Committee on Climate Change (CCC) to ensure that emissions targets are evidence-based and independently assessed.[2] Originally, the Act committed the UK government to greenhouse gas (GHG) emission reductions of at least 80% by 2050, compared to 1990 levels.

In May 2019, the CCC published its "Net-Zero" report in which it stated that the UK should "set and vigorously review an ambitious target to reduce GHGs to zero by 2050". The report identified that much of the policy foundations are in place to meet the new targets, but they need strengthening to deliver action and "delivery must progress with far greater urgency".[3] A key point made in the report is that moving to net-zero emissions makes carbon capture and storage a necessity not an option, and that there is a significant role for hydrogen.

Shortly after the release of the CCC report, on 27 June 2019, the UK became the first major economy to commit by law to reducing GHG emissions to net-zero by 2050.[4]

1.3 Project Overview

Gas is fundamentally important to the current UK energy system, but it is a significant GHG emitter. A net-zero emissions target leaves little or no role for unabated natural gas consumption in the future energy mix. However, if the country's highly developed gas network infrastructure can be repurposed to accept, transport and deliver low carbon and renewable gases such as biomethane and hydrogen, gas can make a valuable contribution to the decarbonisation of the UK energy supply.

In this context, the Energy Networks Association (ENA) commissioned Navigant to explore the role that the gas sector can play in the long-term decarbonisation of the energy system in Great Britain (GB).

[1] UK Government (2019), Digest of UK Energy Statistics
[2] https://www.theccc.org.uk/tackling-climate-change/the-legal-landscape/the-climate-change-act/
[3] https://www.theccc.org.uk/publication/net-zero-technical-report/
[4] https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law

The specific objectives of this project were to assess:

- How low carbon and renewable gases can contribute to a decarbonised 2050 energy system in GB?
- What would be a pathway to achieving such a decarbonised 2050 energy system?
- What is the role of the gas networks along the decarbonisation pathway and in the 2050 energy system?
- What are the near-term, "low regret" actions along the decarbonisation pathway?

The project was undertaken in three phases:

- In **Phase 1**, we developed a "whole system" model to determine the volumes and types of low carbon and renewable gases available in a 2050 decarbonised GB energy system. Two scenarios were modelled: a "Balanced Scenario" and an alternative "Electrified Scenario", reflecting different levels of gas and electricity supply. Our modelling approach and the scenarios are further described in Chapter 2.
- Building on the outputs of Phase 1, we developed a "Pathway", or high-level implementation plan, to meet our Balanced Scenario (see Chapter 3) in **Phase 2**. The Pathway was informed by our scenario analysis and developed qualitatively, incorporating feedback from our engagement with external stakeholders. We also examined a number of impacts along the Pathway and assessed how key uncertainties, such as the commercial viability of carbon capture and storage, may impact the Pathway (see Chapters 4 and 5).
- Finally, in **Phase 3** we developed a "low regrets" action framework that identifies the near-term actions that should be taken to enable the decarbonisation of the GB energy system. The focus is on those actions that should be taken by the gas networks within the RIIO-2[5] regulatory price control period, which runs from 2021 to 2026. The low regret actions are integrated into the Pathway narrative of Chapter 3.

Navigant was supported by Imperial College London[6] in this study, who provided a rigorous academic review and advisory role. This support involved critique and improvement of our modelling approach and outputs, provision of supporting evidence, general periodic review and the review of interim deliverables.

In addition, Navigant engaged with a dedicated external Expert Advisory Group (EAG) throughout the project. The EAG represented a broad range of stakeholders, including representatives from academia, industry and trade associations, project developers, technology providers, NGOs and consumer groups (see Appendix A). The aim of this engagement was to share interim study outputs and to seek input to improve the evidence base and analysis. Three interactive EAG workshops were held, aligned with each project phase. Further stakeholder engagement with CCC, BEIS and Ofgem took place outside of these workshops.

[5] RIIO (**R**evenue=**I**ncentives+**I**nnovation+**O**utputs). See: https://www.ofgem.gov.uk/network-regulation-riio-model/network-price-controls-2021-riio-2/what-riio-2-price-control

[6] The review was coordinated by the Sustainable Gas Institute. See: https://www.sustainablegasinstitute.org/

2. 2050 ENERGY SYSTEM

2.1 Modelling Approach

To assess the cost-optimal way to decarbonise the GB energy system, our modelling approach is based on a 'snapshot' of the energy system in 2050. Our model develops different scenarios of the energy system in 2050 to determine the optimal supply-demand balance that achieves a net-zero emissions state while minimising energy system costs. Our modelling approach leveraged an existing 2050 energy system model developed by Navigant for the *Gas for Climate* (GfC) consortium, a group of European gas transmission system operators (TSOs) and biogas producers, tasked to explore the future of gas and gas infrastructure in a decarbonised EU energy system.[7] Navigant adapted the GfC model to assess the role of gas in a net-zero GB energy system in 2050.

2.1.1 Sectoral Scope

The scope of our model includes four sectors: buildings, industry, transport and power. Each of these sectors must be addressed to decarbonise the GB energy system. The figure below describes the sectors as well as key decarbonisation options and considerations for each. Our analysis does not consider energy demand from other sectors (e.g. agriculture), which are assumed to progress independently towards net-zero in 2050.

BUILDINGS	**The building sector reflects energy demand from residential and commercial buildings**	Buildings can be decarbonised through several low carbon heating options such as hybrid heat systems, all-electric heat pumps, district heating and the deployment of insulation and energy efficiency measures. Individual end users preferences and their acceptance of disruption will need to be balanced against a "whole system" requirement to achieve net-zero at lowest total energy cost.
INDUSTRY	**The industrial sector captures energy demand from all major energy-intensive industries**	The common approach to decarbonise industry is through electrification, but this is only feasible for low and medium temperature industrial processes (e.g. below 150°C). Decarbonising high-temperature processes can be more challenging and while renewable and low carbon gas can replace natural gas, the options are more limited to replace coal.
TRANSPORT	**Transport reflects energy demand from road transport, shipping and aviation**	The transport sector is unique because, for many modes of transportation like aviation, international shipping and road freight, the required infrastructure needs to be similar across Europe to ensure they can operate internationally. As a result, decarbonisation options will tend to be consistent globally with an emphasis on electrification, hydrogen and biomethane (Bio-LNG).
POWER	**The power sector captures electricity generation from all dispatchable and baseload resources**	To ensure a net-zero energy system, low-carbon electricity generation from wind, solar and nuclear power will serve as baseload resources, while natural gas turbines – traditionally used as dispatchable generation – will need to be replaced with biomethane- and/or hydrogen-fired turbines.

Figure 1 Sectors Covered in 2050 Scenario Model

2.1.2 Geographic Scope

The geographic scope of our analysis focuses exclusively on energy supply and demand within GB. However, import capabilities that are critical to meet GB energy demand are also considered. The power sector incorporates electricity interconnection capacities of 20 GW to 25 GW, depending on the 2050 scenario. Biomass imports are also incorporated and are aligned with the CCC's *Bioenergy in a*

[7] Gas for Climate. March 2018. *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*. https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

low-carbon economy report based on its 'Global Governance and Innovation' scenario.[8] Hydrogen imports are not assumed; all hydrogen is assumed to be produced domestically.[9] This assumption is consistent with the CCC's *Hydrogen in a low-carbon economy* report.[10]

Our modelling approach does not consider regional considerations or variations within GB; it treats GB as a single unit.

2.1.3 GHG Emissions

The focus of our model is on achieving net-zero GHG emissions across the buildings, industry, transport and power sectors by 2050. Our analysis does not capture emissions from sectors beyond this scope such as agriculture, land-use (LULUCF[11]), waste, fluorinated-gases (F-gases) or embedded emissions from materials (e.g. emissions associated with cement production used in the construction of nuclear plants).

In a net-zero system, some GHG emissions will occur, but these can be offset by negative emissions generated from renewable energy sources, such as biomethane or biomass. Our two main 2050 scenarios both achieve a net-zero energy system.[12]

Our analysis does not explicitly define a carbon price to achieve net-zero emissions in 2050. Decarbonisation of the four sectors occurs through the adoption of low carbon and renewable energy sources across all four sectors included in the analysis. Since our modelling focuses on a 'snapshot' of 2050, and not the intervening period through to 2050, our approach does not capture the impact a carbon price would have over time on end-user decisions regarding low carbon and renewable sources.

2.2 2050 Scenarios

2.2.1 Scenario Definitions

We developed two 2050 net-zero scenarios to assess the cost-optimal way to decarbonise the GB energy system, and to explore the role of low carbon and renewable gas in a decarbonisation pathway:[13]

- A **Balanced Scenario** in which low carbon and renewable gases are used in a balanced combination with low carbon electricity (further details can be found in Appendix D); and

- An **Electrified Scenario** in which low carbon and renewable gas use is limited to cases where no reasonable energy source alternative exists, such as in certain industrial processes and transport modes and for dispatchable power generation (further details can be found in Appendix E).

[8] Committee on Climate Change (2018). Bioenergy in a low-carbon economy. https://www.theccc.org.uk/publication/biomass-in-a-low-carbon-economy/

[9] An international hydrogen market may develop over time, but we do not assume this within our study.

[10] Committee on Climate Change (2018). Hydrogen in a low-carbon economy. https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/

[11] Land-use, Land-use Change and Forestry.

[12] Our analysis assumes the following global warming potential (GWP) factors: CO_2 = 1, CH_4 = 28, N_2O = 298.

[13] We constructed these two scenarios by analysing the decarbonisation options in each sector and selecting the lowest-cost options while maintaining supply-demand balance at the overall energy system level. The 2050 total system costs of both scenarios are compared in Section 2.2.4. For brevity, we refer to the scenario with lower total system cost as "cost-optimal" in this report. We acknowledge that it is possible to construct other scenarios which could be considered "cost-optimal" in other ways.

In the **Balanced Scenario**, much like today, heat supply in buildings is primarily from gas sources, with hydrogen and biomethane replacing natural gas. Hybrid heat systems become the dominant option for heating buildings, with limited adoption of all-electric heat pumps. In industry, hydrogen becomes the prominent option to displace natural gas in low- and medium-temperature industrial processes, but some electrification of low-temperature processes also occurs. In transport, light and medium road transportation is mostly electrified, with hydrogen and biomethane being used in heavy transport applications like freight. International shipping relies predominantly on Bio-LNG while domestic, short-distance shipping becomes electrified. Aviation relies heavily on bio- and synthetic fuels. In the power sector, hydrogen and biomethane-fired gas turbines replace all natural gas dispatchable generation.

In the **Electrified Scenario**, electricity plays a more significant role in buildings, industry and transport. Buildings are heated exclusively by electricity, with all-electric heat pumps becoming the key choice for heating. In industry, electrification of low-temperature industrial processes becomes the prominent option, but hydrogen remains the main option for high-temperature processes. In transport, there is very limited role for gas in shipping and road transport, with most road transport and shipping relying on electricity, Bio-LNG and advanced biofuels. Since aviation does not rely on low carbon gases, there is no change in energy supply to this sector in the Electrified Scenario. In the power sector, biomass-fired power plants become the main choice; however, given the higher electricity peak loads, there remains a significant role for hydrogen-fired power plants.

Figure 2 summarises the key differences between the Balanced and Electrified Scenarios across the buildings, industry, transport and power sectors.

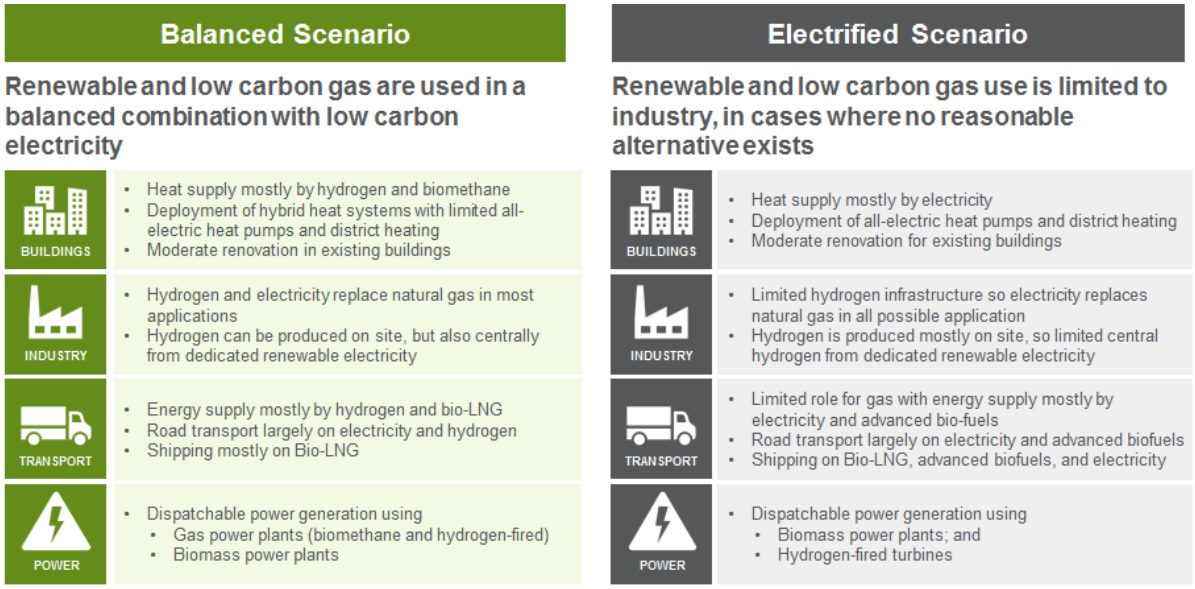


Figure 2 Summary of 2050 Net-Zero Scenarios

Below, we compare the results of our two scenarios, particularly in relation to the role of gas.

2.2.2 Annual Energy Supply

In both scenarios, gas end-use volumes decrease significantly from present levels of around 820 TWh down to approximately 440 TWh in the Balanced Scenario and 220 TWh in the Electrified Scenario. These decreases in gas end-use demand are a result of improvements in energy efficiency and the degree of electrification in each scenario.

In the Balanced Scenario, low carbon and renewable gases play a material role in the 2050 GB energy system. Gas demand volumes are approximately 50% of present levels with hydrogen and biomethane supplying 240 TWh and 200 TWh respectively. In the Electrified Scenario, gas plays a more limited role delivering a combined 220 TWh of energy demand between hydrogen and biomethane, equivalent to 25% of today's gas volumes. The differences between the Balanced and the Electrified Scenarios are reflected across the four sectors:

- **Buildings:** Gas demand from buildings shifts from a combination of gas and electricity in the Balanced Scenario to exclusively electricity in the Electrified Scenario. There is a significant increase in electricity demand as total energy supply from biomethane and hydrogen shifts to electricity. This increase in electricity demand is partially offset by the assumed higher efficiency of the new electric heating.
- **Industry:** Gas demand from industry decreases only slightly in the Electrified Scenario. This is because hydrogen remains the main option for a significant share of industrial demand, even when electrification of low- and medium-temperature industrial processes becomes more prominent.
- **Transport:** Gas demand from shipping and heavy road transport decreases significantly, shifting to electricity, low carbon and renewable gas, and advanced Bio-fuels.
- **Power:** Unlike in the other demand sectors, gas demand in power increases. Hydrogen-fired gas turbines deliver a significant share of dispatchable supply, and alongside biomass power plants, they are used to meet higher electricity peak loads from increased electrification in the other sectors.

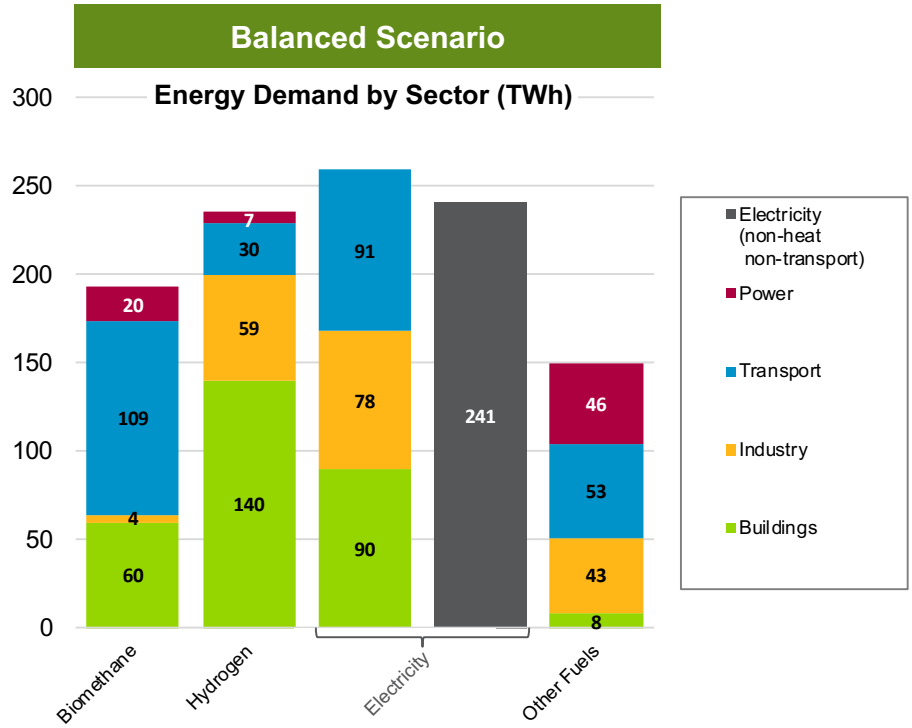


Figure 3 Summary of 2050 Net-Zero Scenarios

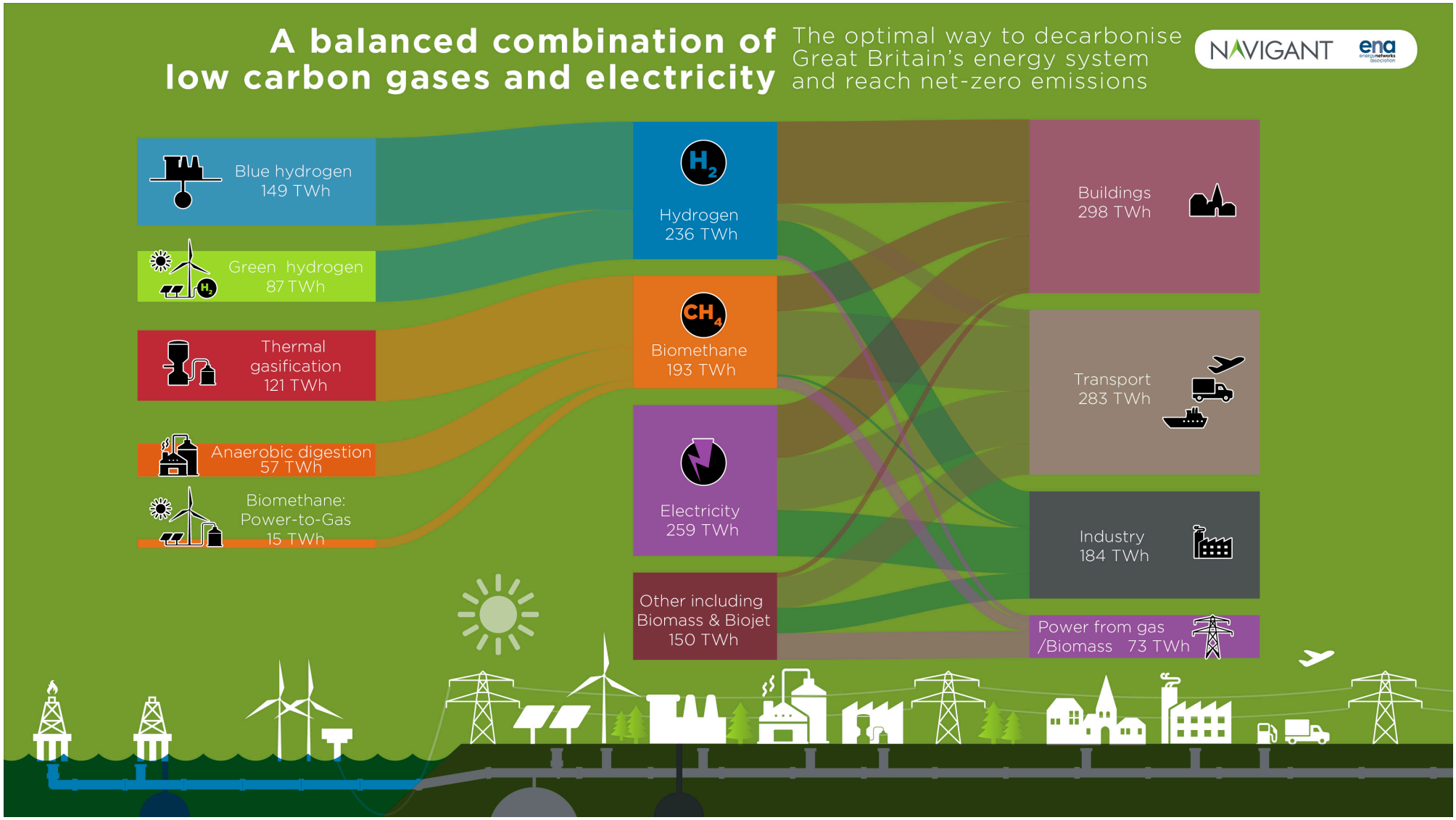


Figure 4 Simplified Sankey Diagram of the Balanced Scenario

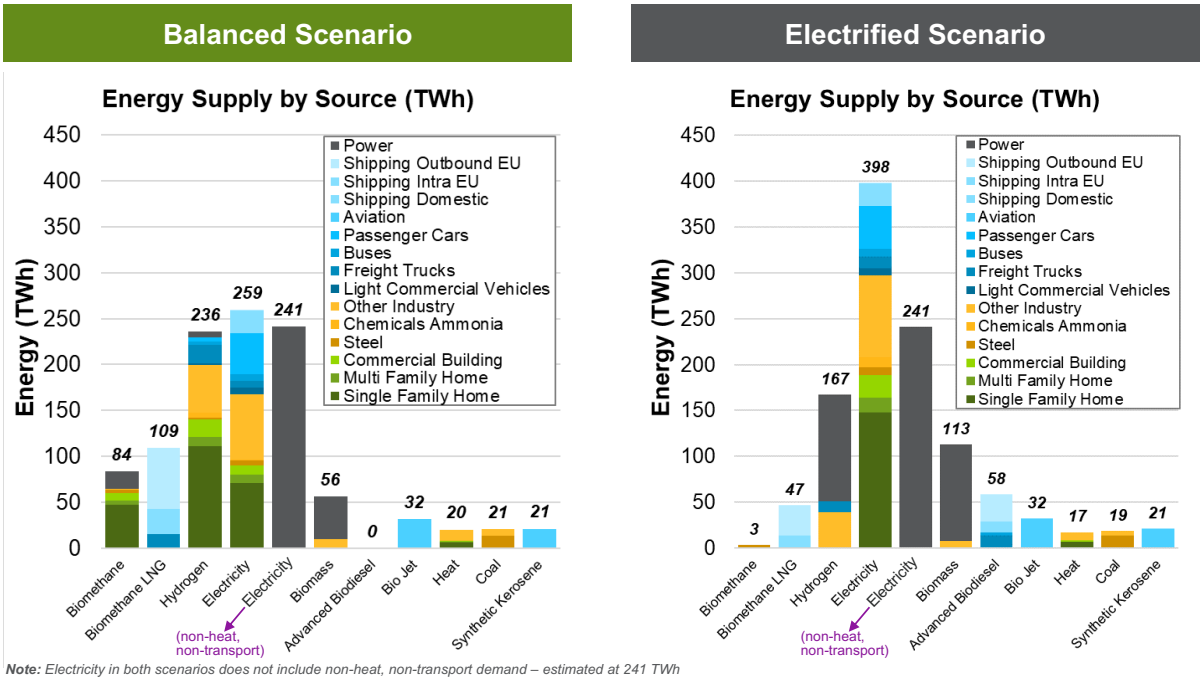


Figure 5 2050 Energy Supply by Scenario[14]

2.2.3 Peak Energy Supply

A key point highlighted by the interplay between gas and electricity networks is how peak energy demand can be met effectively from a whole systems perspective (i.e. through gas, electricity, or a combination). Peak energy flows will drive the level of investment required, particularly in network infrastructure and power generation.

In the Balanced Scenario, with the high deployment of hybrid heat systems, peak energy demand is largely met by gas. In the Electrified Scenario, with full reliance on all-electric heat pumps, peak energy demand is met exclusively by electricity. However, since gas-fired power plants remain the primary option for dispatchable generation in the Electrified Scenario, there is still a major role for low carbon and renewable gas in meeting peak energy demand securely and reliably. In 2050 no natural gas is anticipated to be used for power generation or by end-users. This is illustrated in Figure 6.

- **Gas system peak** is expected to decrease in both the Balanced and Electrified Scenarios compared to today, decreasing from ~5,200 GWh/day down to 3,300 GWh and 4,760 GWh, respectively. This reduction in gas peaks, compared to more significant reductions in annual demand, is attributed largely to the increased use of gas for peak electricity generation. So, while gas plays a more limited role in terms of overall energy supply, it takes on a significantly greater role to meet electricity peak demand. In the Balanced Scenario, gas demand for peak electricity generation accounts for 24% of the gas peak, while in the Electrified Scenario it accounts for 94% of the peak. The graph shows system peak based on peak-day gas volumes. Intra-day hourly gas volumes would show more drastic fluctuations in gas demand, which are likely to pose an increasing challenge for gas networks.

[14] Electricity demand is presented in two categories; (1) electricity demand used to supply heat and for transport and (2) electricity demand for non-heat and non-transport uses. This second category of electricity demand is not relevant in the context of fuel-switching potential and does not change from one scenario to the next as it can only be met through electricity. It includes electricity demand for space cooling, lighting, refrigeration, electronics, among other end-uses.

- **Electricity system peak** is expected to almost double in the Balanced Scenario, from approximately 59 GW today to 116 GW. In the Electrified Scenario, the shift to all-electric heating results in a much higher system peak of 204 GW. While both scenarios represent a major build-out of electricity generation capacity and network reinforcements, the use of gas supply for heat in the Balanced Scenario significantly reduces investment in power generation infrastructure. In contrast, electric heating in the Electrified Scenario forces significant investment in power infrastructure, which in turn requires investment in gas generation infrastructure. As a result, this power and gas peaking capacity has a very low asset utilisation.

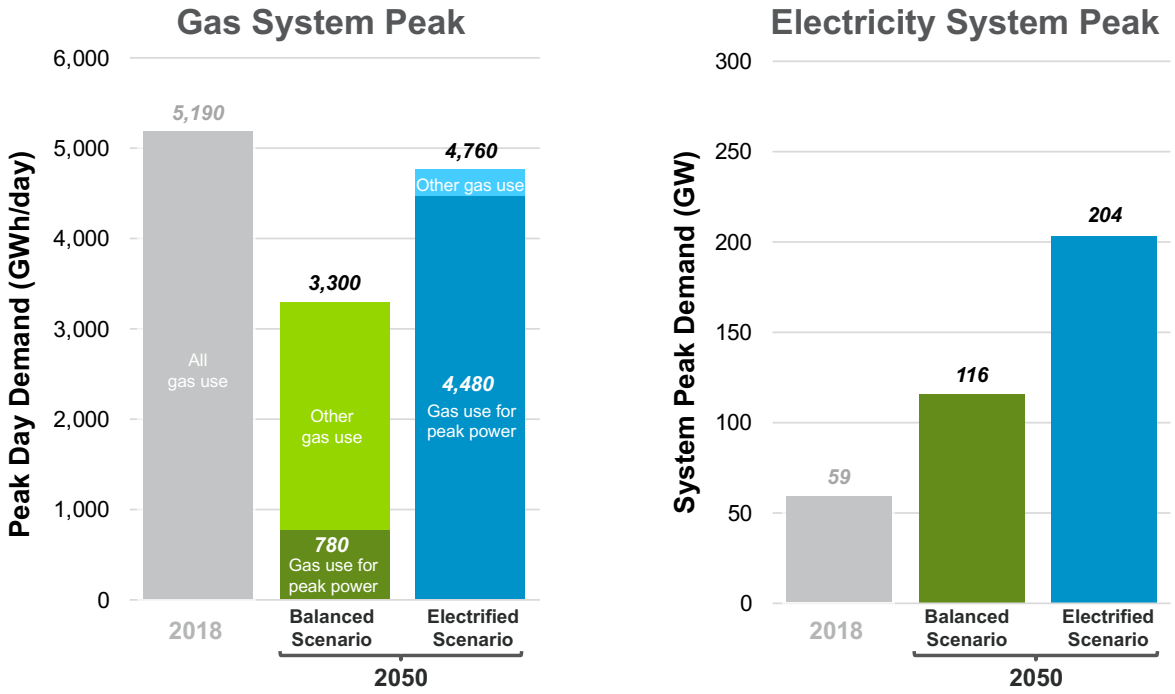


Figure 6 Comparison of Gas and Electricity System Peaks by Scenario

Annual gas demand, as presented earlier in this section, is considerably lower in 2050 than today. As a consequence, gas network capacity in operation today could accommodate a significant share of the gas peak in 2050.[15] Existing gas network capacity offers enough headroom and flexibility to accommodate even higher gas peaks than those projected in our analysis. By comparison, new electricity peaks in 2050 would require significant investments in power generation capacity and network infrastructure.

2.2.4 Total Energy System Cost

Our cost analysis[16] is based on a snapshot of 2050 and the scenario comparison is on an annual basis. Costs over the period of the Pathway will vary (an assessment of this is provided in Chapter 4); for example, the ongoing iron mains replacement programme will finish in 2032 and gas network distribution costs will decrease at this time.

[15] Existing gas network capacity could not accommodate all gas peak demand because it is likely that hydrogen would require some degree of new network infrastructure.

[16] Details of the energy system modelling, including costs assessed are in Appendix F.

Our analysis shows that the Balanced Scenario is lower cost than the Electrified Scenario by GBP13bn/year, equivalent to 12% of total energy system cost in 2050. Since there are multiple differences in terms of energy demand and supply between the Balanced and Electrified Scenarios – including differences across buildings, industry, transport and power – the comparison of energy systems cost is complex. Some of the major cost differences include:

- **Buildings Equipment:** Equipment costs increase from GBP35bn/year in the Balanced Scenario to GBP40bn in the Electrified Scenario. This is attributed to the wholesale adoption of electric heating and the need for stand-alone, all-electric heat pumps.

- **Buildings Energy Costs:** Building energy costs remain largely unchanged with only a minor reduction from GBP16bn down to GBP15bn. This minor reduction in energy costs is a result of the higher efficiency of electric heat pumps, offsetting the higher cost of electricity compared to gas.

- **Power & Gas Infrastructure:** To deal with the much higher electricity peaks, there is a significant increase in power generation capacity costs and electricity network reinforcement costs. Power generation capacity increases from 239 GW in the Balanced Scenario to 358 GW in the Electrified Scenario (see detail in Appendix D). In the gas sector, lower gas demand leads to some decommissioning costs for gas networks, partially offsetting decreased costs in gas production.

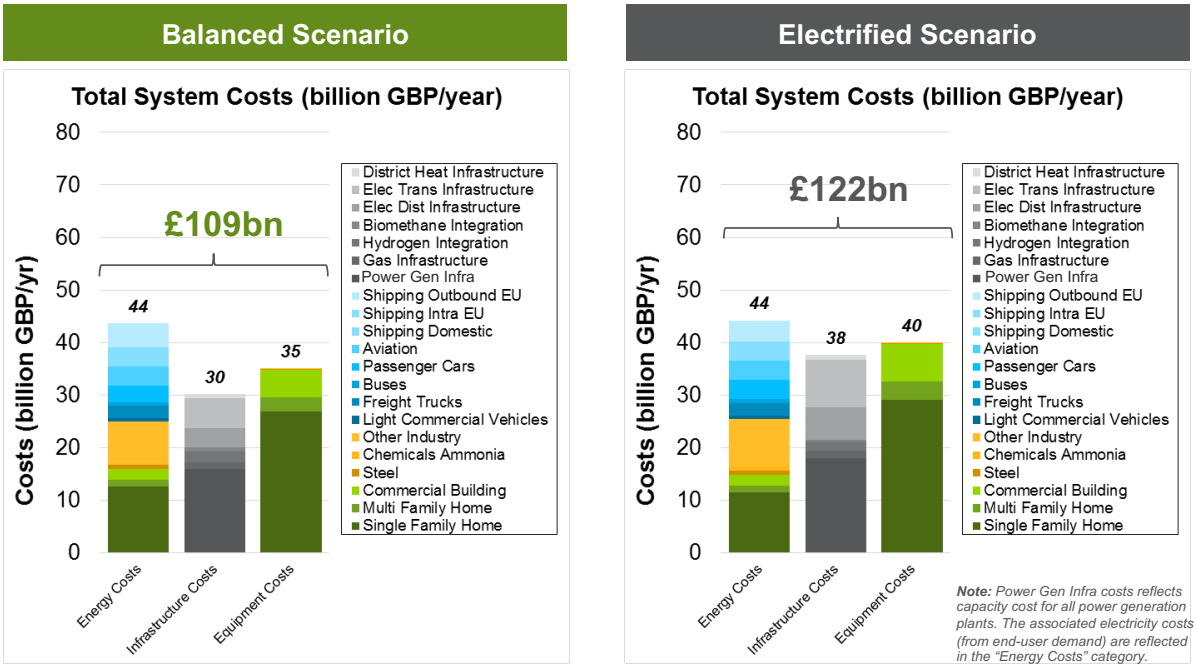


Figure 7 2050 Energy System Costs by Scenario

3. PATHWAY TO A DECARBONISED ENERGY SYSTEM

We have developed a "Pathway", or high-level implementation plan, to deliver our Balanced Scenario. The Pathway was informed by our scenario analysis and developed qualitatively, building on the initial pathway developed by the gas networks, and incorporating feedback from the project's Expert Advisory Group. The second Expert Advisory Group workshop focused specifically on the decarbonisation pathway, considering implications for low carbon and renewable gas supply, end-user transition and the adaptations required by the gas networks.

Our Balanced Scenario, and therefore our Pathway, are not reliant on a single technology or energy source to meet net-zero emissions but utilise multiple technologies and energy sources. We acknowledge that some technologies may develop faster, or costs may change more quickly than we anticipate, and these advances may result in a somewhat different energy mix in 2050 than expected for our 2050 Balanced Scenario. The delivery of the Pathway is also subject to several challenges and uncertainties – we explore the implications of some of the most important of these in Chapter 5.

Our Balanced Scenario is focused geographically on GB and four sectors: buildings, industry, transport and power generation. The focus of our Pathway is on the supply and use of low carbon and renewable gases in the context of our Balanced Scenario.

To achieve the Balanced Scenario, and net-zero emissions, other actions will need to occur in parallel, such as the electrification of passenger cars and supply of synthetic fuels for aviation. These other actions, whilst fundamental to achieving our Balanced Scenario, are not described in detail in our Pathway.

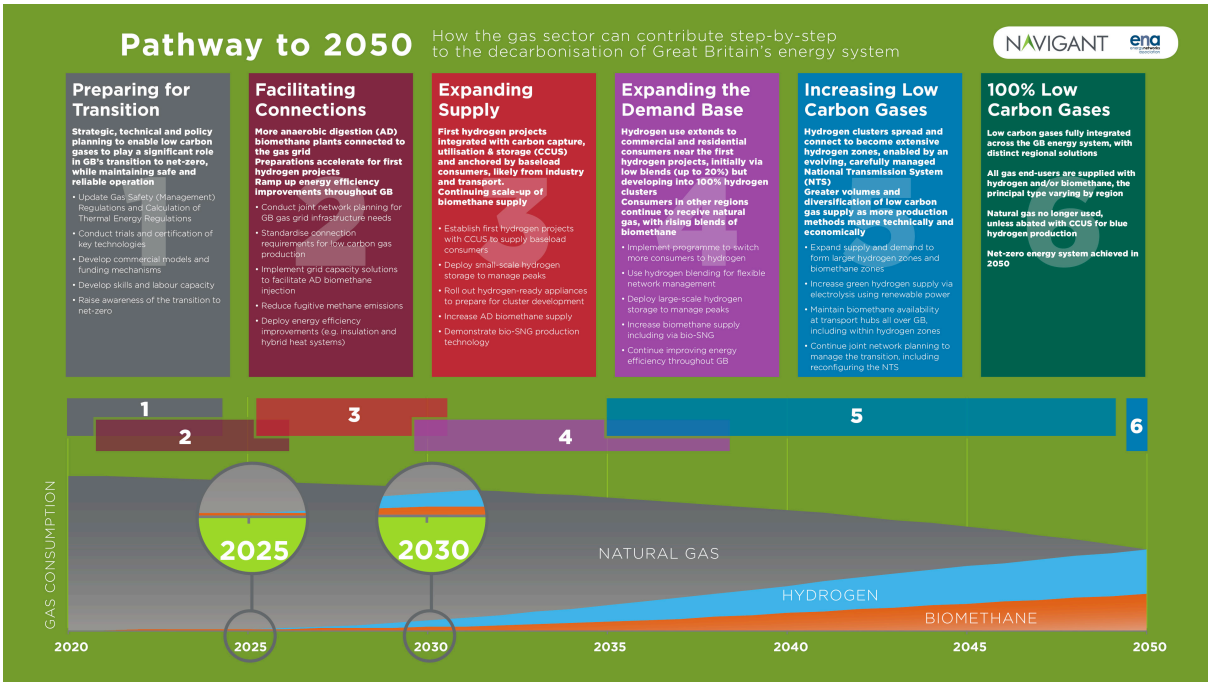


Figure 8 Pathway to 2050[17]

[17] A full-page version of this info-graphic is in Appendix B.

Within the Pathway we have also highlighted actions that we consider as "low regret". That is, actions that should be taken by the gas network companies (or other stakeholders) to advance the implementation of the Pathway as they are necessary for the achievement of a net-zero energy system in 2050. The low regret actions are typically short-term measures, with implementation commencing during the next regulatory period for the gas networks, known as RIIO-2, from 2021 through 2026, covered by parts 1 and 2 of the Pathway. The third Expert Advisory Group workshop focused specifically on low regret actions that can be taken (principally by the gas network companies) as well as the enablers that should be put in place, and barriers that must be overcome to implement these actions. The low regret actions are further described in Appendix G.

Low Regret Action:
Testing and certification of Hydrogen Ready appliances
Timing: Now through to 2020
Responsible: Equipment manufacturers / Gas Network Companies
Approach: Expand and increase coordination across hydrogen development projects such as HyDeploy, Hy4Heat, H100 and Freedom

Example Low Regret Action

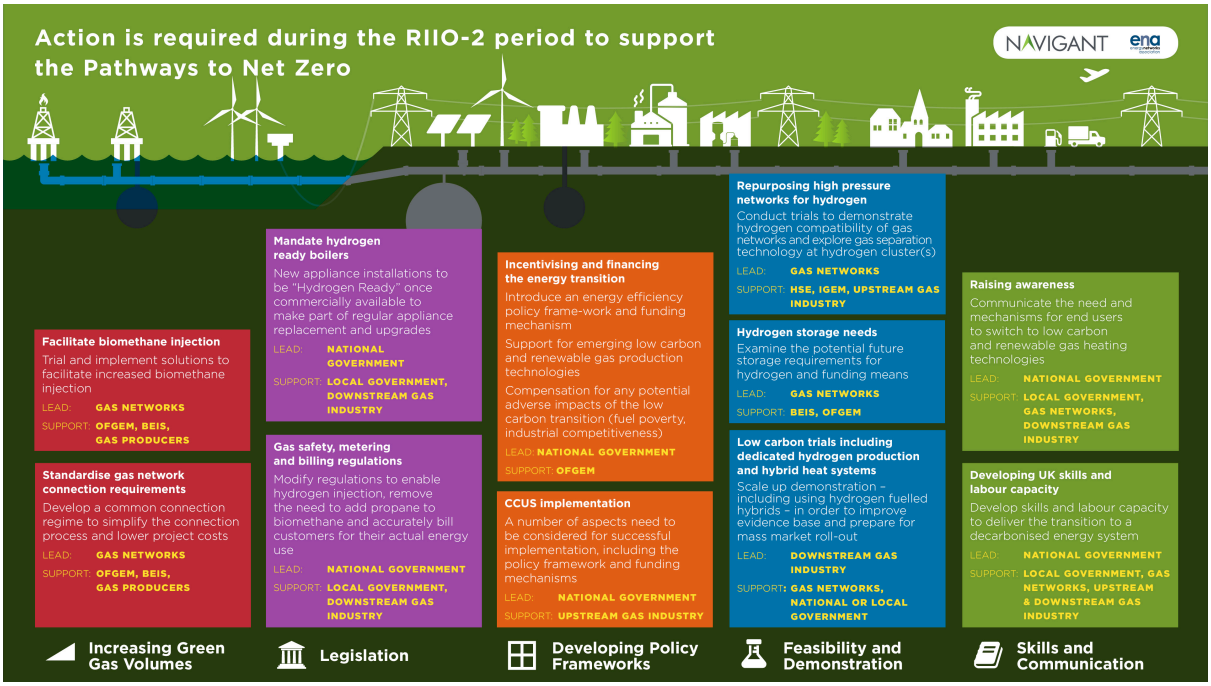


Figure 9 Low Regret Actions During the RIIO-2 Period[18]

From part 3 of the Pathway onwards, we identify actions that typically occur towards the end or after the RIIO-2 period. These actions are required to deliver the overall Pathway, but are often dependent on the timely implementation of the Low Regret Actions we have identified earlier. Where such dependencies exist, these have been highlighted.

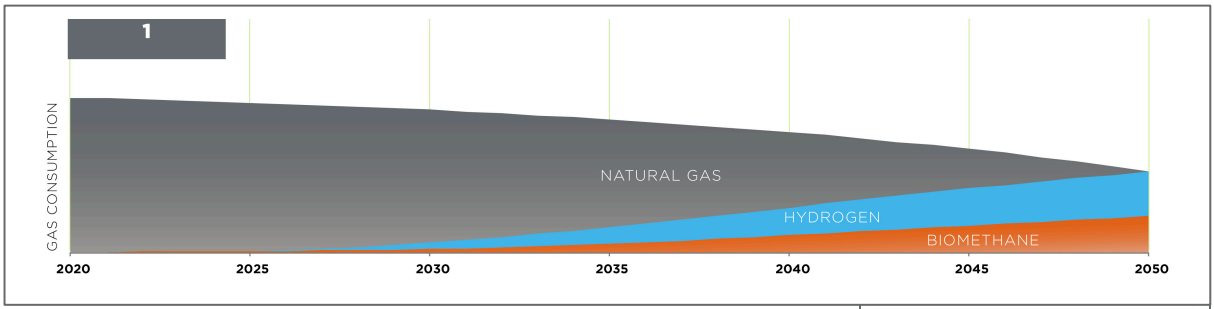
For each action (low regret or otherwise) we provide a short description, timing and identify the stakeholders who are most involved in the action's delivery.

Blending of Hydrogen into Gas Networks
Timing: 2023
(or 2024 if using hydrogen demonstration project)
Responsible: Project and Technology Developers / BEIS / Ofgem / Gas Network Companies
Requirements for Success:
- Updates to GS(M)R and CoTER
- Innovation funding to support technology development
- Business models and policies to support CCUS and extensive deployment of low carbon and renewable gas production

Example Action Post RIIO-2

[18] A full-page version of this info-graphic is in Appendix B.

3.1 Preparing for Transition



In our Balanced Scenario, we anticipate that the use of low carbon and renewable gases will be significant, although the energy supplied to end-users will be lower than it is today for natural gas.[19] Low carbon and renewable gases will:

- Be used in industry for heat and as process feedstock;
- Provide heat in buildings;
- Fuel peak power generation to balance the high proportion of renewable power generation expected in 2050; and
- In addition, be used extensively in the transport sector, in particular for international shipping and also for heavy road freight, where the power required and weight involved for battery-based alternatives is challenging.

Preparing for Transition

Strategic, technical and policy planning to enable low carbon gases to play a significant role in GB's transition to net-zero, while maintaining safe and reliable operation

- Update Gas Safety (Management) Regulations and Calculation of Thermal Energy Regulations
- Conduct trials and certification of key technologies
- Develop commercial models and funding mechanisms
- Develop skills and labour capacity
- Raise awareness of the transition to net-zero

This initial part of the Pathway is focused on the strategic, technical and policy planning required during the RIIO-2 period to enable low carbon and renewable gases to play a significant role in GB's transition to net-zero emissions, while maintaining safe and reliable operation of the gas networks.

Current gas sector regulations make it difficult to introduce hydrogen and relatively expensive to connect a biomethane facility to the gas networks. These fundamental regulations need to be adapted so low carbon and renewable gas can readily contribute to a net-zero emission energy system.

There are several technologies that need to be developed and tested to enable low carbon and renewable gases to make a full contribution to the decarbonisation of the energy system. The capability of the gas networks, particularly high-pressure transmission system, to transport hydrogen needs to be proved. The capability to convert end-users safely and efficiently to hydrogen requires additional testing.

The gas networks and gas suppliers will need a comprehensive and coherent policy (from BEIS) and regulatory (from Ofgem) framework to be developed during the RIIO-2 period so that there is a clear, long-term commitment to the gas networks, enabling them to make the investments required to decarbonise the energy system.

CCUS is a vital part of the Pathway to net-zero emissions. The technologies to implement CCUS are not novel and are often used in the oil and gas industry. Wider application of these technologies, however, requires a stable long-term policy and business models to be implemented. Other policies will need to be adapted from current frameworks or new policies developed to support end-users adapt to the new energy system and to support widespread adoption of some, currently expensive, technologies.

[19] Volumetric flows in the gas networks will be higher due to hydrogen having a lower energy density than natural gas.

The requirement to actively participate in the transition to a decarbonised energy system will have to be broadly communicated to all stakeholders. New skills, additional labour capacity and investment in the supply chain will be required to implement the energy system transition by 2050, supported by appropriate price controls for the gas networks companies.

3.1.1 Gas Safety, Metering and Billing Regulations

Modifications to Gas Safety (Management) Regulations[20] (GS(M)R) and Calculation of Thermal Energy Regulations (CoTER) are needed to:

- Enable the addition of hydrogen to the gas networks;
- Remove the requirement to add propane to biomethane production; and
- Accurately bill customers for the energy they use.

Low Regret Action:
Update gas safety, metering and billing regulations to facilitate and enable greater supply and use of low carbon and renewable gases
Timing: IGEM Hydrogen Standard to be completed by end 2019. GS(M)R to be revised by mid- 2020
Responsible: Gas Networks / IGEM / Health and Safety Executive / Ofgem / Government
Approach: IGEM Gas Quality Standards Working Group, Future Billing Methodology and Real Time Networks

The current regulations restrict the quantity of hydrogen that can be supplied by the gas system to 0.1% (volume). This regulation effectively means that currently no hydrogen can be injected into the gas networks and any hydrogen projects must be “off-grid”. For example, in the HyDeploy project the Health & Safety Executive has given permission to run a live test of blended hydrogen and natural gas on part of the private gas network at Keele University campus in Staffordshire.

Biomethane produced from an anaerobic digestion plant is of a lower calorific value than the gas quality specification in the current regulations. To address this, about 4% (volume) of propane is added to the biomethane. The requirement to add propane and undertake accurate measurement is estimated to add costs of GBP150,000 per year for a 500 m^3 per hour capacity plant. This cost negatively impacts the business case of many potential biomethane projects. Furthermore, given that the propane source is typically fossil fuel based this practice also increases greenhouse gas emissions of the biomethane.

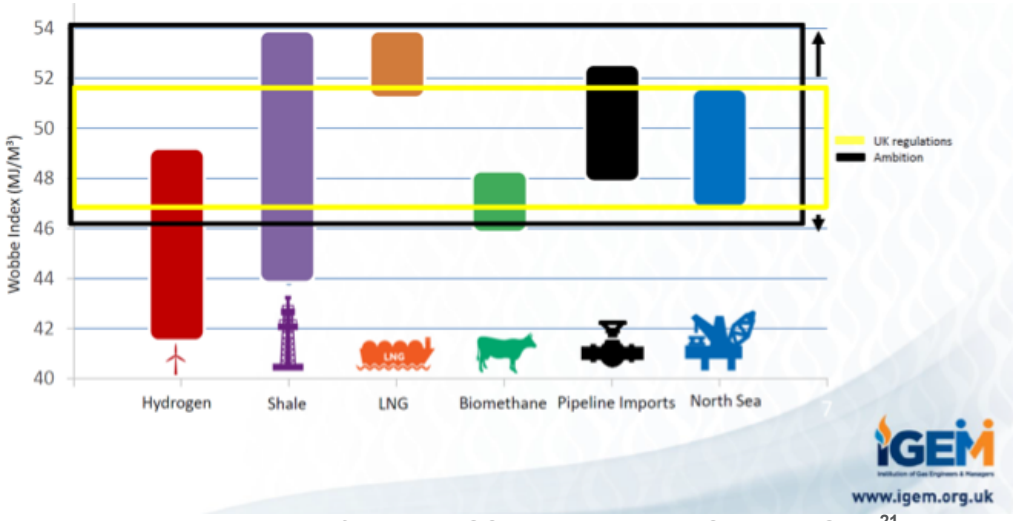


Figure 10 Drivers for a new GS(M)R standard. (Source: IGEM[21])

[20] Health and Safety Executive. Gas supply legislation, guidance and submitting gas transporter safety cases. http://www.hse.gov.uk/gas/supply/legislation.htm

GS(M)R and CoTER need to be revised to address these, and a range of other related issues, in order that low carbon and renewable gases can make a significant contribution to decarbonising our gas supply. The Institute of Gas Engineers and Managers (IGEM) has set up a Gas Quality Standards Working Group that is currently developing recommendations as to how GS(M)R should be modified. Specifically, IGEM has been looking at widening the Wobbe Index limits and raising the hydrogen content limit from 0.1% to 20%. A recent study for the Hy4Heat project has recommended a hydrogen purity standard of 98% as well as proposing limits on impurities for hydrogen supply. This work has served as input to the hydrogen standards being developed by IGEM, which when completed will supersede Schedule 3 of GS(M)R, subject to enabling legislation. ENA is active in discussions concerning amending the GS(M)R.

The current metering and billing systems are set up based on a calculation of the quality of gas (i.e. energy content per unit of volume) in thirteen "charging areas" of the gas networks to determine a flow weighted average calorific value (FWACV). As a consequence, the quality of gas within these charging zones is tightly controlled. The introduction of significant quantities of low carbon and renewable gas will mean that gas quality will likely vary within these current charging areas.

The metering and billing procedures will need to change to ensure that end-users pay for the energy they receive, rather than the volume of gas as is the case today, thereby facilitating more flexible but still robust CoTER and also reducing barriers of entry for low carbon and renewable gas suppliers. Cadent is leading a Future Billing Methodology[22] (FBM) innovation project that is looking at ways to update the commercial framework which controls the way gas is distributed and measured for billing. Alongside FBM, SGN's Real Time Networks[23] (RTN) project is installing and demonstrating sensing technologies, hardware and software to support new billing mechanisms based on calculated thermal energy. Together these two projects will enable greater volumes of low carbon and renewable gas to enter the gas networks and for end-users to be accurately billed for their energy use.

3.1.2 Trials and Certification of Key Technologies

Hydrogen will make a significant contribution to the decarbonisation of the energy system in our Balanced Scenario. However, hydrogen compatibility with some elements of the gas network infrastructure, as well as some end-user equipment, has not yet been fully demonstrated. Several projects are ongoing to address these issues.

Low Regret Action:
Trials to validate repurposing of high-pressure gas networks for hydrogen transportation
Timing: Now through to 2030
Responsible: Gas Networks / Health and Safety Executive / IGEM / Upstream Gas Industry
Approach: HyNTS and LTS Futures innovation projects. Trials for gas separation technologies at grid scale

Gas Networks: The gas distribution companies are undertaking the iron mains replacement programme to install hydrogen compatible (plastic) pipework within their low-pressure networks. This program is due to be completed by 2032.

National Grid is running the HyNTS innovation programme that is assessing the potential to blend hydrogen into the National Transmission System (NTS). In partnership with SGN's Aberdeen Vision project[24], HyNTS will be part of a project to provide a 2% hydrogen blend to the NTS, which provides nearly 40% of GB's natural gas supply from St Fergus. The Aberdeen Vision project will also test the technoeconomic case for the construction a new 100% hydrogen pipeline between St Fergus and Aberdeen that would supply hydrogen (20% blended and eventually 100%) for heat and for transport projects.

National Grid is also working with the Health and Safety Executive (HSE) to assess the capability of the NTS to transport hydrogen, or a blend of hydrogen and natural gas. The report on the current desk-based research is due in 2019. National Grid has already announced some preliminary findings.

[21] IGEM (2017), Gas Quality Standards, UNC Transmission Workgroup Meeting 7th December. https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/page/2017-12/UNC%20Transmission%20Working%20Group.pdf
[22] https://futurebillingmethodology.com/
[23] https://www.sgn.co.uk/about-us/more-than-pipes/future-of-gas/hydrogen/real-time-networks
[24] http://www.h2aberdeen.com/

Initial results from the first phase of the project suggest that some sections of the NTS pipework would be able to accommodate hydrogen blends, and potentially 100% hydrogen, provided that the oxygen content of the gas is around 200 to 500 ppm (parts per million). The presence of oxygen at this concentration mitigates the impact of hydrogen embrittlement of the steel pipework. This oxygen content is below the current threshold specified in GS(M)R.

National Grid has identified an approach to determine which parts of the NTS could be most easily re-purposed for hydrogen and also identify sub-optimal areas where more detailed condition surveys, testing or re-engineering might be required. Further work is also required to consider the impact of hydrogen on other network components such as valves, soft seals and compressors.

Gas separation technologies (a process to split a blended gas stream into its component parts) are widely used in process industries and they could potentially be used to enable the separation of hydrogen and methane within the gas networks. Costain and National Grid are currently assessing the application of these technologies; further research and grid-scale trials are required. Our Pathway does not assume grid-scale deployment of these separation technologies, but the implications of successfully developing such technologies for the gas networks are explored in Chapter 5.

Appliances and Equipment: "Hydrogen Ready" appliances and equipment (e.g. boilers) are designed so that they can operate at up to 20% blend of hydrogen (by volume), or otherwise at 100% hydrogen.[25] Deployment of such systems will provide a means of future proofing end-user systems in advance of a roll-out to 100% hydrogen in a region. Equipment manufacturers indicate that "Hydrogen Ready" gas boilers will be commercially available from around 2026. A programme of testing and certification will be necessary before these systems can be rolled-out to end-users.

Low Regret Action:
Testing and certification of Hydrogen Ready appliances
Timing: Now through to 2026
Responsible: Equipment manufacturers / Gas Networks
Approach: Expand and increase coordination across hydrogen development projects such as HyDeploy, Hy4Heat, H100 and Freedom

3.1.3 Policy, Commercial Models and Funding Mechanisms

To achieve a net-zero energy system, how we produce, supply and use energy will need to change. All energy users will see a change in how they consume energy, either as a change in the type of gas they use, or as a move in part or wholly to electricity. Most energy users will also require installation of new equipment or appliances. This transition will create requirements that will need to be funded – these funding issues must be addressed no matter what final net-zero emission scenario is reached.

CCUS: The successful implementation of Carbon Capture, Utilisation and Storage (CCUS) is fundamental to achieving net-zero emissions. Our analysis, and that of others such as the CCC, confirms that the widespread application of CCUS is not optional, but a requirement. CCUS is needed in our Balanced Scenario and all our other scenarios if net-zero emissions are to be achieved in 2050. CCUS fulfils three key objectives:

- Lowers carbon emissions from hydrogen produced through the reforming of natural gas;
- Provides "negative emissions" when combined with renewable gas or biomass power generation, or the production of Bio-SNG. Negative emissions can be used to offset residual

Low Regret Action:
Develop funding mechanisms to support large scale CCUS deployment
Timing: Now through to 2025
Responsible: BEIS / Upstream Gas Industry
Approach: Clean Growth Strategy and CCUS Action Plan

[25] A boiler could be fitted with a self-calibrating combustion system to enable a wider range of hydrogen blend to be used, but these have several drawbacks (see Section 3.3.3).

emissions from hydrogen produced by natural gas reforming and emissions from other hard-to-decarbonise sectors, such as parts of industry or agriculture; and

- Applied to industry, CCUS can materially reduce process and other emissions.

To achieve these objectives, long-term commercially viable business models for the large-scale application of CCUS are needed. The Government's Clean Growth Strategy and CCUS Action Plan[26] set out an initial CCUS framework and allocated GBP44 million for CCUS demonstration projects. From this, funding has recently been approved for several projects including a project offshore from Aberdeen and another in Teesside. A Tata Chemicals carbon utilisation project in Cheshire will also receive Government funding.

Much of the current focus is on carbon storage, however utilisation of carbon also has an important role to play in accelerating CCUS by offsetting costs and contributing to a circular carbon economy. Carbon utilisation technologies are expanding with commercial plants producing polymers, fuels, chemicals etc. and there are also direct uses of carbon. There is significant ongoing research and development effort in this area, which could benefit from continued support to help the most promising technologies towards commercialisation.

The intent of any CCUS project is that carbon is locked away indefinitely. However, the companies that will undertake the CCUS projects will be unable to bear the entire commercial risk of permanent carbon storage. For large scale CCUS projects to be realised a viable risk allocation policy must be developed. This may require the Government to take on long term carbon storage risk, in much the same way as it does for waste fuel storage in the nuclear industry.

The government is currently undertaking two consultation processes: one on business models for CCUS[27] and a second on the re-use of oil and gas assets for CCUS.[28] The Government has stated that the business models should provide: value to the economy and be cost efficient; encourage investment; share costs and risk fairly; and that they should become subsidy free in time, if possible.

Low Regret Action:
Develop cost sharing methodology for the low carbon transition
Timing: Now through to 2025
Responsible: BEIS / Ofgem
Approach: Heat Decarbonisation Strategy

Cost Sharing: End-users in different regions of GB may get different choices of energy supply than they do today. Some will have access to biomethane and electricity, others to hydrogen and electricity, and possibly others only to electricity. The prices of these energy carriers will be different to each other – end-users in different parts of GB will have different energy costs. Furthermore, the timing of the transition to a new energy supply will vary across the country. This is likely to be a particular concern for industry as their economic competitiveness locally and globally will be impacted by the timing of the energy system transition. *How should these differences be equalised, if at all?*

We contend that the prices of new alternative energy, sources such as low carbon and renewable gases, should not be artificially managed for the majority of domestic end-users in much the same way as prices of heating oil, propane, biomass fuels etc. are currently left to market forces to dictate. Whilst the mix of fuels in GB's energy supply network will change, regional differences in access to fuels and their associated supply costs is not a new phenomenon.

If the overall cost of energy increases for some domestic customers due to the changing energy mix, then Government will need to explore options to increase support for those in fuel poverty.

[26] UK Government (2018), The UK carbon capture, usage and storage (CCUS) deployment pathway: an action plan. https://www.gov.uk/government/publications/the-uk-carbon-capture-usage-and-storage-ccus-deployment-pathway-an-action-plan

[27] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf

[28] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819901/reuse-oil-gas-assets-ccus-projects.pdf

Further, Government should carefully assess the implications of potential increases in fuel costs for industry to avoid any competitive distortions, internationally and, albeit less likely, across GB. In the event that the changing fuel mix leads to a disproportionately higher cost for certain sectors subject to international competition, Government may need to introduce assistance measures. We would recommend that a similar (albeit not identical) approach be applied in terms of assessment and assistance to that currently used to assess the impact of carbon pricing and associated assistance for some industry.

Government will need to carefully assess whether the changing mix of fuels disproportionately increases the costs to industry and creates further risk for some energy intensive industries. A variety of policy mechanisms could address this, including a Contract for Difference (CfD) like support payment to address temporary cost differences for impacted industry, carbon pricing and carbon price support tax exemptions, temporary corporation tax reductions for new equipment purchases, or a system of targeted support for business with significant competitive challenges and high energy use.

Financing Early Investment: Adapting a heating system to use hydrogen, applying insulation and other energy efficiency measures, and installing hybrid heat systems will require significant upfront expenditure by end-users. This expenditure may act as a deterrent to many end-users to fully participate in the energy system transition. *How should these expenditures be financed to enable full end-user participation?*

Low Regret Action:
Develop energy efficiency policy framework and funding mechanism
Timing: Now through to 2025
Responsible: BEIS / Ofgem
Approach Revised Green Deal "pay as you save" model or RHI

There are a range of policy support and assistance measures which Government could explore to help bridge the cost of necessary new appliances (boilers, cookers, hobs, gas fires, etc), installation of heat pumps, upgrading insulation and adaptation to the new energy supply mix. We recommend building on existing policy structures, such as the Renewable Heat Incentive (RHI), energy supplier obligations or interest free loans, to help aid the energy transition. This policy mix could be supplemented by revising the Green Deal "pay as you save" model to help pay for measures which have very long pay back periods. Mandates for new appliance installations to be "Hydrogen Ready" from 2026 and a long lead time for new compliant appliance installation will also help make these investment decisions cost effective and a more straightforward part of regular appliance replacement and upgrades.

Low Regret Action:
Mandate installation of "Hydrogen Ready" Boilers
Timing: 2026+
Responsible: Ministry of Housing, Communities & Local Government
Approach: Building regulations

Technology Support: To achieve the net-zero emission target, government policy will need to support several technologies that have the potential to be a significant part of a decarbonised energy system, but today are relatively expensive to implement. These policies will need to have similar ambition to those that have successfully delivered significant cost reductions in the deployment of offshore wind power generation. *What are the appropriate incentive mechanisms?*

We recommend tailoring and extending the existing policy infrastructure, such as CfDs, RHI and Feed in Tariffs (FITs) to assist the development and cost reduction of new technologies. Large scale plants to produce hydrogen and biomethane together with carbon sequestration technologies will be expensive initially. Such investments will depend on long term support mechanisms such as the Renewables Obligation to attract the necessary investment.

Low Regret Action:
Develop energy infrastructure funding policy and commercial mechanisms
Timing: Now through to 2022/23 extension to RHI then post 2023 new models to supplement (or replace) RHI
Responsible: BEIS / Ofgem
Approach: Possible combination of CfDs, RHI and FITs

The RHI is due to end on 31 March 2021. The Government has not yet announced how it will encourage the decarbonisation of heating after this date. To meet the net-zero emission target, the Greening the Gas Grid policy announced in the 2019 Chancellor's Spring Statement will need to lead to, for example, an extension of the RHI for 2-3 years and then longer term a replacement by new CfDs, low carbon and renewable gas supplier obligations, or other policy mechanisms.

3.1.4 Skills and Labour Capacity

The transition to a low carbon energy system will require new skills and additional labour capacity, including gas engineers, plumbers, appliance installers and engineers. Training programmes will need to be developed and offered to "re-skill" the existing workforce on new technologies. A "Gas Safe" hydrogen appliance accreditation is also needed. Raising awareness of the opportunities within the energy sector is also important to attract new labour to the sector.

Low Regret Action:
Develop skills and labour capacity to deliver the transition to a decarbonised energy system
Timing: Now through to 2035
Responsible: BEIS / Department for Education / local enterprise partnerships / Gas Networks / Equipment manufacturers and installers
Approach: Training courses and apprenticeships

3.1.5 Raise Awareness of the Transition to Net-Zero

Effective communication of what needs to be achieved, how that will be accomplished, when actions need to be taken and by whom will be essential to facilitate the Pathway implementation. The communications programme will need to address all of the stakeholders in the energy system transition. The most important stakeholder group are energy end-users: industry; building owners and occupiers; transportation companies.

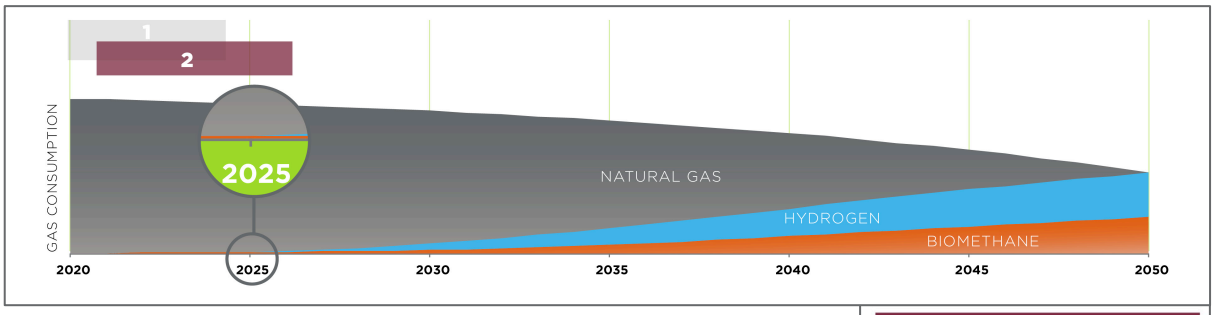
Low Regret Action:
Communicate the need and mechanisms for end-users to switch to low carbon and renewable gas heating technologies
Timing: 2020 through to 2040+
Responsible: National and local government / local enterprise partnerships / industry associations (installers, suppliers) / consumer groups
Approach: National and targeted local campaigns

Energy end-users are likely to look to advice from energy suppliers, equipment manufacturers and particularly installers of low carbon appliances. Any communication programme will need to ensure that this stakeholder group is aligned to the long-term net-zero target and the actions that need to be taken by energy end-users. There are many other issues that need to be considered for a clear and consistent communication policy to be an effective tool to aid the achievement of a net-zero energy system by 2050. Lessons can be learnt from transitions including the ongoing roll out of consumer smart meters and the recent move from analogue to digital television.

The decarbonisation of heat is not currently an issue of which there is good awareness among the public, unlike the decarbonisation of transport, which enjoys a good level of coverage in the media, stimulated by manufacturers of electric and hybrid cars, air quality concerns, government grant schemes for new vehicles, lower vehicle tax rates and the ban on petrol and diesel cars sales by 2040.

A key issue for any public media campaign is its timing and the need for an event that raises the profile of the need for low carbon heat but importantly shows how it will be achieved. Hy4Heat is an example of a project that could provide a catalyst for a more high-profile public information campaign when Hy4Heat commences its community trials phase after 2021. Alongside that, equipment manufacturers can start to raise awareness through communicating that new appliance purchases will be future proofed for any gas quality changes.

3.2 Facilitating Connections



Facilitating Connections

More anaerobic digestion (AD) biomethane plants connected to the gas grid
Preparations accelerate for first hydrogen projects
Ramp up energy efficiency improvements throughout GB

- Conduct joint network planning for GB gas grid infrastructure needs
- Standardise connection requirements for low carbon gas production
- Implement grid capacity solutions to facilitate AD biomethane injection
- Reduce fugitive methane emissions
- Deploy energy efficiency improvements (e.g. insulation and hybrid heat systems)

This second part of the Pathway focuses on connecting more biomethane production facilities to the gas grid (rather than using untreated biogas for power generation) and preparing for the development of hydrogen production and use through demonstration projects and infrastructure planning during the RIIO-2 period.

Currently there is 13 TWh of biogas production capacity in GB, most of which is used directly for power generation at the biogas production site. Only about 30% of current biogas production is upgraded to biomethane suitable for injection into the gas network. Changes are needed to incentivise biomethane injection into the gas networks, rather than the inefficient utilisation of the untreated biogas for power generation. To achieve this, appropriate policy (from BEIS) and regulation (from Ofgem) will be required during RIIO-2, such as the extension or replacement of the RHI scheme (Section 3.1.3).

We consider that biomethane production through anaerobic digestion, has the potential to supply nearly 60 TWh by 2050. However, to achieve this, connection to the gas network needs to be made simpler and less expensive to implement. The gas network companies also need to provide greater access to network capacity for biomethane producers and support biomethane access to off-grid end-users. The increasing use of biomethane could, if not implemented correctly, lead to fugitive methane emissions. The gas network companies can support biomethane producers in the implementation of best practices in leak detection and elimination.

Hydrogen production in GB is currently around 27 TWh,[29] primarily for use in industry (particularly oil refining and fertiliser production). It's use in other sectors, such as transport, is typically limited to trials and small-scale demonstration projects. The successful and timely roll-out of hydrogen production will require the gas network companies to develop a joint plan and programme of works to adapt gas infrastructure for the transportation of hydrogen. For example, new large-scale hydrogen storage facilities will be required to support future Hydrogen Cluster development and the planning for this is needed early in the Pathway implementation due to long lead times for these facilities. Large scale demonstration hydrogen production projects, combined with CCUS, are required to confirm the viability and cost of these technologies.

The widespread applicability of low carbon heat systems (hybrid heat pumps and hydrogen boilers) also needs further testing and development.

[29] Committee on Climate Change (2018), Hydrogen in a low-carbon economy. https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf

3.2.1 Standardise Connection Requirements for Low Carbon Gas Production

At the moment, the technical requirements to connect a distributed gas source to the gas network, such as an anaerobic digestion biomethane facility, vary depending upon which gas distribution company the project is attempting to connect to. Element Energy[30] estimated that this divergence in connection requirements increases costs, on average, by about GBP90,000 per connection. This expenditure is a material cost to a biomethane project and can be a significant disincentive to connect to the gas network.

Low Regret Action:
Standardise low carbon and renewable gas network connection requirements
Timing: 2020 - 2021
Responsible: Gas Networks / Ofgem / BEIS / IGEM / Gas producers
Approach: Manage a cross-industry consultation to assess network connection options with the overall aim of realising cost savings for gas suppers, taking on board any lessons from the Project CLoCC and related initiatives

Developing a common connection regime for all the GB gas networks is necessary to simplify the connection process and hence lower project costs, especially for biomethane projects in the near term. With a view to the longer term, the connection regime should ideally be designed to facilitate both biomethane and hydrogen supply projects.

Connections to the gas network have in the past been both costly and time consuming to implement; however, Project CLoCC[31] (Customer Low Cost Connection) is designed to improve and standardise processes, drive down cost, and share best practice across the gas networks.

A similar process is required for the lower pressure distribution connections and, in support of this, some of the gas distribution companies have been developing processes for customers or gas suppliers to lay their own connecting gas pipe, subject to certain conditions.

3.2.2 Implement Grid Capacity Solutions to Facilitate Biomethane Injection

Potential biomethane projects are often in rural locations where local gas demand is relatively low. As a result, many viable biomethane projects are unable to connect to the gas grid as there is not the capacity in the local low-pressure network to utilise the gas during the whole year. In addition, the lack of capacity can lead to the flaring of gas in existing biomethane plants, particularly during summer months when local demand for gas is low.

Low Regret Action:
Implement grid capacity solutions to facilitate increased biomethane injection
Timing: 2020+
Responsible: Gas Networks / BEIS / Ofgem / Gas Producers
Approach: Gas Network Companies to develop an interactive on-line mapping tool to identify potential connection points and match this with current / planned biomethane supply potential. In-grid compression of gas to higher tiers and / or interconnection of local networks

Implementation of flexible network capacity solutions are needed to significantly increase the gas networks' scope to receive biomethane supplies in areas of the lower pressure gas network that have limited local demand.

For example, network compression (enabling gas to move up to high pressure tiers in the network) can be implemented strategically for reverse flow enabling flexible injection and management of biomethane. Work led by the University of South Wales suggests that biomethane could also be flexibly produced from acetic acid at an anaerobic digestion facility, allowing grid injection and daily demand profiles to be matched.

Successful implementation of this part of the Pathway is dependent on several earlier steps. Government policies are required to incentivise biomethane production. BEIS will need to extend or replace the RHI and Ofgem will need to establish a regulatory regime (Section 3.1.3) that supports the gas network companies' investment to increase local gas network capacity. Changes to the gas

[30] Element Energy (2017), Distributed gas sources, Final Report for National Grid Distribution Ltd., SGN, Wales and West Utilities.
[31] http://projectclocc.com/

safety, metering and billing regulations (Section 3.1.1) will help to lower connection costs by removing the need to add propane to the biomethane production.

3.2.3 Biomethane Deployment in Off-Grid Buildings

In our Balanced Scenario, there is a role for biomethane in off-gas grid buildings serving peak demand to support the deployment of hybrid heat system utilisation.

Low Regret Action:
Evaluate opportunities for Biomethane deployment in off-grid buildings
Timing: 2020 - 2030
Responsible: Gas Networks
Approach: Assess options for biomethane plant configuration (e.g. centralised upgrading plant supplied by small-scale anaerobic digestion plants vs. decentralised) and supply logistics (e.g. compressed or liquefied gas transport)

There is an opportunity to explore this aspect further through supply chain development and trials working in conjunction with biomethane producers and existing LPG suppliers (who have storage, logistics, billing systems and importantly potential customers for the trials). The gas network companies can facilitate these trials, acting as overall project co-ordinator, as in the Freedom project. As with the grid capacity solutions, BEIS and Ofgem will need to put in place appropriate policies and regulation (Section 3.1.3) to support the implementation of this part of the Pathway.

3.2.4 Reducing Fugitive Methane Emissions

Fugitive methane emissions may arise during biomethane production and also from transporting and distributing biomethane across the gas networks.

Low Regret Action:
Explore opportunities to reduce fugitive methane emissions
Timing: 2020+
Responsible: Gas Networks / Biomethane Trade Associations / Health and Safety Executive / Defra
Approach: GNCs to oversee desk-based research, co-ordination of trials at biomethane producers and dissemination of project results.

The ongoing iron mains replacement programme is already facilitating a reduction in methane losses from the distribution networks and is scheduled for completion in 2032.

Fugitive methane emissions may also occur at natural gas reforming facilities and associated infrastructure for the production of hydrogen. It is critical to explore opportunities to eliminate / reduce these emissions given the high global warming potential of methane (especially over the short term) and the resulting impact this has on the potential of biomethane and hydrogen to contribute to a net-zero energy system.

Work has been carried out by Ricardo to develop methodologies for fugitive methane leakage in a range of anaerobic digestion based biomethane production plants.[32] The proposed methodologies could also be applied to gas infrastructure and similar processes could be applied to hydrogen.

Where plants are regulated it could be a condition of the permit/licence to carry out periodic monitoring and reporting of methane emissions, the type and frequency of monitoring specified in the permit. Larger plants could be subject to annual third-party site monitoring and reporting.

A consultation on the control of fugitive gas emissions should be called by the Government involving sector bodies such as Anaerobic Digestion & Bioresources Association, Renewable Energy Association and IGEM etc. on the best way to monitor, report and control fugitive emissions of gas to atmosphere.

[32] https://ee.ricardo.com/news/understanding-methane-leakage-from-ad-installations-a-new-methodology

3.2.5 Network Planning for GB Gas Grid Infrastructure Needs

Our Balanced Scenario includes a significant role for both biomethane and hydrogen. Initially the integration of both gases into the energy system will be straightforward. Biomethane will blend into the natural gas supply. Hydrogen will be supplied directly to anchor end-users or potentially blended at low quantities into specific parts of the gas network.

Low Regret Action:
Develop a joint gas network company technical plan and programme for redeployment of GB gas grid infrastructure for Hydrogen
Timing: 2020 – 2023
Responsible: Gas Networks / BEIS / Infrastructure and Projects Authority / Ofgem
Approach: Set-up a 'Gas Grid Reuse and Repurpose' project team (GGRR) consisting of senior technical representatives from all GNCs and chaired by ENA

However as low carbon and renewable gases become a material part of the gas supply as described in the latter parts of our Pathway, management of the gas networks, and specifically the contribution of the NTS will become more complex.

The Gas Network Companies (GNCs) should jointly produce an agreed future gas network plan and programme of work to use, adapt and/or repurpose the existing high-pressure transmission and distribution gas grid infrastructure to facilitate the supply of hydrogen (including an assessment of future carbon dioxide infrastructure needs).

The specific recommendations from this Network Planning process will be dependent on the commercial viability of several key technologies (Section 3.1.2), such the ability to utilise the NTS for large scale hydrogen transportation and the applicability of gas separation technologies to supply individual hydrogen and (bio)methane streams from a gas blend.

To help inform this work, National Grid (for the NTS) and the distribution companies (for the local transmission systems) will need to evaluate the detailed network capacity requirements of the high pressure network transition to hydrogen at a regional level. The planning will need to include an assessment of operational aspects of hydrogen deployment, such as the potential implications on linepack and network management.

In addition to detailed network planning, the planning process for the development of hydrogen storage is required. In our Balanced Scenario, hydrogen provides a significant contribution to building heat. This demand is highly seasonal and large-scale hydrogen storage will be required to manage this.

Low Regret Action:
Examine the potential future seasonal storage requirements for hydrogen clusters
Timing: 2020 – 2023
Responsible: Gas Networks / Gas Storage Companies / Hydrogen suppliers / BEIS / Infrastructure and Projects Authority
Approach: Identify candidate storage sites and develop budgeted plans for short-listed strategically located storage facilities

Storage capacity typically takes up to 7 years to implement and this is unlikely to happen if solely left to the market. To promote early investment, BEIS and Ofgem will need to identify a means of mitigating the commercial risk caused by potentially low summer / winter hydrogen price differentials for storage owners and funders.

Later parts of the Pathway, specifically the development large-scale hydrogen storage (Section 3.4.4) and the expansion of the Hydrogen Clusters (Section 3.4.3) in to the building sector will depend on timely planning of the hydrogen storage requirements and a regulatory regime (such as a regulated asset base model) that will support storage investment.

3.2.6 Demonstration of Hydrogen Production with CCUS

Hydrogen production through steam methane reforming (SMR) is widely used in process industries but historically has not been combined with CCUS to abate the carbon emissions. Hydrogen production with CCUS is fundamental to our Pathway and the achievement of net-zero emissions by 2050. Therefore, there is a requirement to demonstrate at large scale that these technologies can be successfully combined. The development of natural gas based hydrogen production demonstration plants with CCUS (Blue Hydrogen) using both SMR and autothermal reforming (ATR) would enable a comparison of the two technologies to be made and would confirm the technical and commercial viability of hydrogen production with CCUS. The hydrogen produced could be utilised in a refinery, chemicals plant or transport project.

Low Regret Action:
Support development of hydrogen production projects with CCUS
Timing: 2021 – 2023+
Responsible: Hydrogen suppliers / Gas Networks / BEIS / Infrastructure and Projects Authority
Approach: Build on projects such as Aberdeen Vision, Acorn and Cavendish

To successfully achieve this part of the Pathway policies and business models for CCUS development need to be put in place by Government (Section 3.1.3). The entire Pathway is dependent on the successful commercial development of Blue Hydrogen.

3.2.7 Deployment of Low Carbon Heat Systems

Gas boilers are widely used in the energy system and currently take a significant share of GB's overall natural gas demand. In 2050, it would be challenging to cost effectively produce enough low carbon and renewable gas to completely replace natural gas to meet building heat requirements. Other complementary solutions will be required.

Hybrid heat systems, using either biomethane or hydrogen, are an integral component of our Balanced Scenario. Small-scale demonstrations of methane-based hybrid heat systems have been held to date, most notably under the Freedom Project. A next step would be to scale up these demonstrations (to over 1,000 homes) and include hydrogen fuelled hybrids in order to improve the evidence base and prepare the market for mass roll-out (envisaged between 2025 and 2040). Hydrogen fuelled hybrid heat systems would be needed for use in regions without biomethane in the grid.

All-Electric Heat Pumps: A condensing boiler can achieve an efficiency of close to 95%. An air source heat pump, which works by evaporating and condensing an intermediate fluid to move heat from the outside environment into a building, can achieve efficiencies of 400%, and potentially even higher. Over an entire heating season, the average efficiency (or "Seasonal Performance Factor") of a residential air source heat pump in practice is typically between 200% and 300%.[33]

Whilst the efficiency of a heat pump is much better than that of gas fired condensing boiler, the temperature produced by a heat pump (30-50ºC) is typically lower than from a gas fired boiler (70-90ºC). The efficiency and performance of a heat pump also varies with the outside temperature. In cold winter temperatures, the heat pump efficiency can drop to 100% and that may mean a heat pump alone may be unable to meet the comfort requirements of a building occupier. The peak heat demand in winter coincides with low heat pump efficiencies, resulting in sharply higher demand for electricity at these times. Although this situation may only occur for

Low Regret Action:
Large scale demonstration of hybrid heat systems using both methane and hydrogen
Timing: Now through to 2026
Responsible: Equipment manufacturers / Gas Networks
Approach: Expansion of projects such as HyDeploy, Hy4Heat, H100 and Freedom

[33] Ground source heat pumps have different performance and efficiency profiles but are assumed to make up a minority of heat pump installations in our Balanced Scenario. Where a heat pump (or hybrid heat system) is used, air source heat pumps are assumed to be the dominant technology in our Balanced Scenario.

only a few weeks every year, the overall system must nonetheless be designed to accommodate periods of cold weather.

Hybrid Heat Systems: Hybrid heat systems combine a heat pump with a gas fired boiler. When a hybrid heating system is installed in a building, any existing gas boiler could be retained, with an electric heat pump plumbed into the system and a new control system added. It may, however, be beneficial to replace the boiler at the same time as the heat pump installation if it is old and inefficient. When a boiler is replaced, it should be changed for a "Hydrogen Ready" boiler once they are commercially available on the market, assumed to be from 2026. This would result in the hybrid heat system being ready for the potential introduction of hydrogen (or biomethane) in the building's area.

The heat pump will provide base load heat and the gas boiler would contribute to meet peak heat demand. Compared to all-electric heat pumps, the advantages of hybrid heat systems are:

- They can make use of the existing gas infrastructure, reducing the required expansion of electricity grids;
- A smaller and lower cost heat pump can be selected compared to all-electric systems;
- Customer disruption is less than an all-electric solution due to more modest insulation requirements (as explained in the following section);
- They can deliver heat using the building's existing heat delivery systems, avoiding replacement of pipework and radiators; and
- The equipment is relatively low cost, because expensive incremental heat pump capacity is substituted with low-cost gas boiler capacity.

Compared to a hydrogen boiler, a hybrid heat system reduces annual gas demand, which in turn reduces the required amount of low carbon and renewable gas. As a significant part of energy to heat buildings will be Blue Hydrogen, there will be residual emissions from that production process, and a need to compensate for these by using Bio-SNG with CCUS, partly depending on imported biomass. This would be challenging to achieve because the required quantity of biomass imports would rise well beyond the reasonable levels assumed in our Balanced Scenario. Furthermore, low carbon hydrogen is virtually non-existent today and will remain scarce until the late 2020s. Hydrogen is needed in sectors other than buildings so using hydrogen as efficiently as possible in buildings is important for the overall energy system. The total final energy demand for heating is reduced as well, due to the fact that the heat pump provides its share of the heat with an efficiency of (well) over 100%. In our analysis use of a hybrid heat system reduces energy demand by 19% for a building with moderate renovation.

Over time, the incremental up-front cost of installing a hybrid heat system will be offset by energy cost savings given that the price of electricity for heating (at many times of the day and days of the year) will be appreciably lower than incremental hydrogen heating costs, acknowledging that during peak heating this is unlikely to hold true.

Navigant's Gas for Climate work[34] for seven leading European gas transmission system operators and two renewable gas producers' associations considered the benefits and drawbacks of various low carbon heating systems and concluded that a hybrid heat system (whether biomethane or hydrogen fuelled) provides the best balance of installation expenditure, energy cost, disruption caused by the equipment installation, and requirement to improve insulation. Hybrid heat pumps were assessed as having advantages for both biomethane and hydrogen gas supply.

Our Balanced Scenario assumes widespread adoption of Hybrid Heat Systems: 75% of homes, i.e. the vast majority of those that retain a gas connection, move eventually to a hybrid heat system.[35]

[34] https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

[35] In line with Navigant's Gas for Climate assessment we assume that all buildings that retain a gas connection move to a hybrid heating system.

20% of homes use all electric heat pumps (air or ground source) and the remaining properties are able to utilise waste industrial heat via heat networks.

Building Insulation: To provide the same level of comfort to a building occupier as a gas fired boiler, a heat pump, in general, needs to be combined with significant improvements in building insulation and additional equipment to deliver low temperature heat (larger pipework, larger heat emitters and potentially underfloor heating).

Some insulation measures, such as roof insulation, are relatively simple and low cost to implement. Renovations such as the replacement of single pane glazing with high performance double or triple glazed windows and doors can likely be achieved with limited disruption, but these improvements can be expensive. Other insulation improvements such as underfloor insulation and heating or solid wall insulation cladding can be both highly disruptive and expensive.

The Gas for Climate team also identified that building renovation (installation of energy efficiency measures, such as insulation) complements the use of both all electric heat pumps and hybrid heat systems. The Committee on Climate Change (CCC) foresees a central role for insulation and insulation improvement also forms a key part in Government policies to increase buildings energy efficiency.

In our Balanced Scenario, and in line with our previous Gas for Climate project, we assume that a moderate level of renovation should complement a hybrid heat system. This moderate renovation would involve installation of high performance glazing and loft insulation. Overall energy efficiency gains for this moderate renovation would typically be 21%, similar to the gains in the "Core Options" scenario in the CCC's recent net-zero report.

Where a building uses an all-electric heat pump in our Balanced Scenario,[36] extensive renovation is assumed to be required, since the heating system will have to be able to operate at low temperature even in cold winter weather. Extensive renovation is potentially highly disruptive and requires installation of high-performance glazing and insulation to the loft, underfloor and walls. Wall insulation could be cavity based if available or cladding if a solid wall. Overall efficiency gains for this extensive renovation would typically be in the region of 54%.

While we recommend that the rollout of "Hydrogen Ready" boilers should be mandated (Section 3.1.3) once they become commercially available (assumed to be 2026), the same approach is probably not plausible for other low carbon heat options. A "Hydrogen Ready" boiler is similar to a like-for-like replacement and would have a fairly limited difference in both cost and disruption to installing a new natural gas boiler. A heat pump, whether all electric or hybrid system, will require more extensive changes within a property and it is unlikely that the Government will be able to mandate this level of disruption. Even adding a heat pump as part of a hybrid heat systems (which is less disruptive than the changes required for an all-electric heat pump) is likely to have to be incentivised, rather than mandated. Initially, the level of incentive offered may need to be significant. The incentive may not always have to be monetary. Heat pumps have the potential to offer cooling capability as well as heating and therefore a low carbon system that can provide year-round comfort could prove to be persuasive.

Government will need to develop policies which drive the take-up of hybrid heat systems and overcome the range of different barriers which discourage property owners and developers from installing these new and potentially disruptive technologies in their buildings. Barriers such as: the upfront costs of installing equipment; the split incentive between landlords and tenants; property owners unaware of the benefits or not prepared to install new and novel equipment in what is normally their biggest asset; and the disruption from installing equipment such as heat pumps and insulation, may all restrict the take up. The challenges are made all the more complicated when overlaid with the broad sections of society (homeowners, businesses, commercial property owners)

[36] In the Electrified Scenario moderate renovation is used for buildings with all-electric heat pumps.

who will need to act. A suite of policies will be needed to address these barriers and provide the right incentives to different stakeholder groups which would likely include:

Obligatory policy options which require certain actions to take place, such as:

- Amendments to building regulations requiring the installation of technologies and equipment in new builds and major renovations;
- Requirements for hybrid heating system controls to be “smart” and communication grid-connected, enabling them to be capable of receiving fuel / appliance switching signals for the benefit of the whole energy system; and
- The development of product standards, banning the least efficient technology types.

Economic tools, which provide a financial incentive to act, such as:

- VAT rebates / discounts on the installed equipment;
- Interest free loans (through a revolving financing fund similar to the successful Carbon Trust SME Loan Scheme) for the installation of low carbon equipment;
- Council tax or business rate discounts for properties installing new technologies;
- Stamp duty rebates or reductions for properties with installed technologies; and
- White certificate schemes which would allow some form of trading between entities meeting targets by installing equipment types.

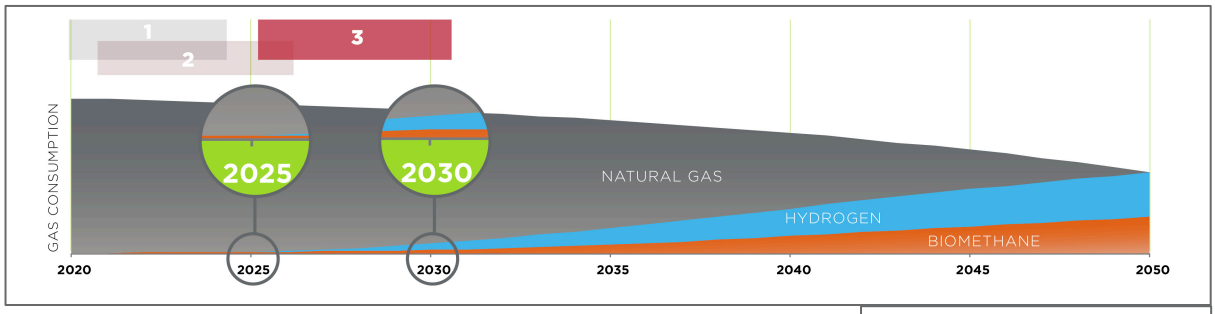
Supplier obligations which require the energy companies to meet targets for the installation of equipment types, similar to the UK’s current Energy Company Obligation (ECO3) programme.

Awareness raising programmes designed to improve understanding of both the economic and comfort (heating and cooling potential) benefits available from the new technologies, such as:

- Community led schemes managed by local authorities;
- Energy labelling; and
- Government led media campaigns such as those used around smart meters and the digital TV switch over.

We recognise that there are some significant challenges in deployment of low carbon heat systems and insulation, and we test some alternative scenarios in Chapter 5.

3.3 Expanding Supply



Expanding Supply

First hydrogen projects integrated with carbon capture, utilisation & storage (CCUS) and anchored by baseload consumers, likely from industry and transport.
Continuing scale-up of biomethane supply

- Establish first hydrogen projects with CCUS to supply baseload consumers
- Deploy small-scale hydrogen storage to manage peaks
- Roll out hydrogen-ready appliances to prepare for cluster development
- Increase AD biomethane supply
- Demonstrate bio-SNG production technology

The previous parts of the Pathway are intended to lay the foundations for the widescale deployment of low carbon and renewable gas across the gas networks. This and the following parts of the Pathway set out the practical steps that need to be taken to implement the supply and use of low carbon and renewable gas.

Biomethane: The overall approach of our Pathway is to promote and develop biomethane supply sources, initially anaerobic digestion, and latterly Bio-SNG to directly replace natural gas. The major challenge for the gas networks will be to manage supply from a large number of small, highly distributed biomethane sources. This is a significant change from the current situation where most natural gas enters the networks through a small number of large-scale facilities such as the gas terminals for domestic gas production or pipeline imports, and the liquefied natural gas import terminals at Isle of Grain and South Wales.

Hydrogen: The overall approach of our Pathway is to develop Hydrogen Clusters, initially based on anchor industrial (and transport) end-users. Hydrogen use would then expand to other industrial users and then into the buildings sector. Once converted, a gas user would be supplied with 100% hydrogen. Blending of hydrogen into unconverted sections of the gas networks (up to a maximum of 20% by volume) would be used to help balance hydrogen supply and demand. The major challenge for the gas networks will be to manage and coordinate the complex process of converting discrete sections of the gas networks (along with end-users) to 100% hydrogen.

An alternative pathway approach for hydrogen was considered but ultimately rejected. In the alternative approach, the proportion of hydrogen in the gas networks would increase gradually over time, so that by 2050 all gas users would receive a blend of biomethane and hydrogen. This would be far simpler to implement from a gas network perspective. However, a continuously changing, or even a stepped, hydrogen blend would be highly problematic for end-users to deal with. Feedback from the project's Expert Advisory Group highlighted two significant issues:

- Firstly, industry requires stability in gas supply. A change to 100% hydrogen will require changes to processes and equipment but was assessed as being manageable. A highly variable gas quality would be far more challenging for industrial processes and equipment to deal with.

- Secondly, in the buildings sector, gas boilers can currently accommodate a hydrogen blend of up to 20% (volume), but not beyond this. "Hydrogen-Ready" appliances currently in development will be capable of using gas with up to 20% hydrogen, or 100% hydrogen. As a consequence of this feedback, the Hydrogen Cluster approach was preferred.

The need to follow a cluster-based approach for hydrogen deployment into the gas network means that the deployment of low carbon and renewable gases will be highly regionalised. While hydrogen deployment will be cluster-based (principally led by industrial end-users and then moving into the building sector), the deployment of biomethane will be more progressive, essentially "filling in the gaps" between the Hydrogen Clusters.

3.3.1 Anchor Hydrogen End-Users

Convert Anchor End-Users to Hydrogen
Timing: 2025+
Responsible: BEIS / Ofgem / Gas Network Companies / Industry / Hydrogen Producers etc
Requirements for Success:
- Policy and business models to support CCUS
- Incentives and support mechanism for industry / transport to convert to hydrogen
- Commercially viable Blue Hydrogen production

In our Pathway, low carbon hydrogen production will start in a small number of geographic areas. In the initial stages of hydrogen development, we anticipate that most new hydrogen production will be Blue Hydrogen (i.e. through the reforming of natural gas combined with CCUS). Consequently, these hydrogen production facilities will need to be located where they have access to both an existing supply of natural gas and access to potential carbon storage facilities. It is therefore likely that initial hydrogen production and use will be based on the east coasts of Scotland and England, or near to Morecambe Bay in Northwest England. Other industrial areas without easy access to local, domestic carbon sequestration options may seek to develop export opportunities for carbon dioxide for sequestration elsewhere.

Low carbon hydrogen can also be produced by electrolysis of water, either through dedicated or otherwise curtailed renewable electricity supply (Green Hydrogen). As of today, such electrolysis is not considered cost competitive with the expected cost of Blue Hydrogen, although we expect that the costs will eventually equalise by the late 2030s. Nevertheless, some of the initial hydrogen production may come from large-scale electrolysis demonstration projects. For example, BP and Nouryon (formerly AkzoNobel Specialty Chemicals), are currently assessing the feasibility of supplying BP's refinery in Rotterdam with hydrogen produced from a 250 MW electrolyser.[37]

The initial use of low carbon hydrogen is likely to be in industry, particularly those industries that currently produce hydrogen for their processes (such as chemicals, refining and fertilisers), or industries that are able to convert their processes cost effectively to hydrogen to reduce their emissions.

Local transport systems, such as bus networks, could also be significant early adopters of hydrogen. Bus operators typically have centralised maintenance and fuel depots to which hydrogen could be supplied. For example, the H_2 Aberdeen project uses a 1 MW electrolyser to provide hydrogen for a small fleet of 10 buses.

These anchor end-users will require a 100% hydrogen supply, so specific hydrogen network infrastructure will be required to meet this requirement (i.e. a direct connection between end-users and the low carbon hydrogen supply source). This could be through repurposing of existing local infrastructure, or construction of new hydrogen specific pipelines.

[37] https://www.nouryon.com/news-and-events/news-overview/2019/bp-nouryon-and-port-of-rotterdam-partner-on-green-hydrogen-study/

3.3.2 Small-Scale Hydrogen Storage

Small-Scale Hydrogen Storage
Timing: 2025+
Responsible: End-Users / Hydrogen Producers / Gas Network Companies
Requirements for Success:
- Incentives and support mechanism for industry / transport to convert to hydrogen
- Network and hydrogen storage planning

Our Pathway anticipates that initial hydrogen developments will focus on end-users (industrial and transport) with a steady baseload demand that can be matched to initial hydrogen supply. Any flexibility that may be required by these initial hydrogen end-users would ideally be modest and limited to daily fluctuations. To manage these peaks, small-scale hydrogen storage tanks could be deployed at end-user and/or producer sites. For example, a transport project would require storage to enable end-of-day refuelling of the vehicle fleet. Another source of flexibility would be the linepack in any hydrogen pipeline connections, although this is likely to be very limited.

3.3.3 Hydrogen-Ready Appliance Roll-Out

Installation of Hydrogen Ready Boilers
Timing: 2026+
Responsible: BEIS / Ministry of Housing, Communities & Local Government / Equipment Manufacturers / Gas Network Companies
Requirements for Success:
- Proven safety case for hydrogen in buildings
- Mandate for Hydrogen Ready boiler installation
- Enough trained hydrogen gas fitters and installers
- Effective communication of energy transition
- Incentives and support mechanism for building owners / occupiers to install hydrogen ready appliances

To create a Hydrogen Cluster of significant scale, the supply of hydrogen will eventually need to extend to the building sector. This will require modifying or replacing domestic and commercial consumers' appliances to use hydrogen at more than a 20% (volume) blend.

"Hydrogen Ready" boilers: Boilers on sale today are required to be compatible with hydrogen content of up to 20% (volume).[38] However, these boilers cannot be modified to use hydrogen at higher concentrations. To facilitate the supply of 100% hydrogen to the buildings sector, several boiler manufacturers are developing "Hydrogen Ready" appliances.

"Hydrogen Ready" boilers currently in development are being designed to work with a hydrogen blend of up to 20% volume and to be easily converted to accept a 100% hydrogen supply. The switch to 100% hydrogen would require an engineer to make some basic modifications to the installed "Hydrogen Ready" boiler. This process is expected to take around 1 hour. Once converted to 100% hydrogen, the end-users would be permanently switched to the new fuel.

[38] The EU Gas Appliance Directive (GAD) requires domestic appliances, such as gas boilers, brought to market to be tested at blends of 20% hydrogen. The Directive was implemented in the UK through the Gas Appliances (Safety) Regulations 1995. The Health and Safety Executive (HSE) estimates that only 2% of gas appliances in the UK will be pre-GAD in 2020.

Specific areas within the gas distribution system will need to be isolated and moved over to hydrogen in a coordinated action. This area-by-area rollout of hydrogen was considered in detail by the H21 Leeds City Gate project as well as the follow-on H21 North of England project.

A Hydrogen Cluster will develop in a phased approach broadly following the roll-out and commissioning strategy described in the 2018 H21 North of England Report:

- Following delineation of the cluster area and assessment of metering points and demand it will be possible to develop a plan for supply, conversion and commissioning.
- The H21 approach is to construct hydrogen production plants with inter-seasonal storage back up. The hydrogen production plants build rate would match the projected conversion rate (GWh/year).
- Construction of the hydrogen production plants in the H21 North of England plan commences 2 years before the first conversions so that the first production facilities are commissioned, proven and have produced hydrogen for storage, including the required cushion gas.
- The conversion process in H21 takes place for 6 months April-September when demand is low and alternative domestic cooking facilities can be provided, but no heating.
- H21 anticipates that 2GWh demand can be converted with 3,000 plumbers and gas fitters per year operating in three locations in parallel.
- In winter, works involve surveying and preparation for the subsequent summer period conversions. This would employ half the summer workforce.
- The gas network conversion work will be carried out sequentially:
  High Pressure > Intermediate Pressure > Low Pressure
  and will need specific assessment for isolation points, bypasses etc. to ensure those areas not converted to hydrogen continue to receive uninterrupted natural gas supplies.

At its peak the conversion from town gas to natural gas 2.3 million metering points were converted per year. By comparison, the H21 North of England conversion involves 3.7 million domestic metering points and 37,000 non-domestic with conversion planned to take place over 7 years 2028-2035.

Alternative Options to get "Hydrogen Ready": The "Hydrogen Ready" boilers currently in development would not readily have the capability to use a gas supply with a concentration of hydrogen between 20% and 100% (volume). Two options could be available to provide flexibility on the concentration of hydrogen:

- **Gas Burner Replacement:** One option would be to install a different gas burner capable of using a different hydrogen concentration, for example 40%. However, there are difficulties with this approach. Firstly, the tolerance of hydrogen concentration in the gas supply would be very small. It would be challenging for the gas networks, working with the gas suppliers, to maintain a hydrogen blend within the required tolerance. Secondly, each subsequent change in hydrogen concentration would require an engineer visit to adapt the boiler to the new hydrogen concentration.

- **Self-Calibrating Combustion System:** A second option would be to utilise a self-calibrating combustion management system within the boiler. However, these systems are expensive to install, materially adding to the cost of the boiler and require additional maintenance and regular component replacements. Additionally, the current performance of this equipment is not considered reliable enough for mass rollout to end-users. However, use of such systems would significantly reduce the complexity of the hydrogen rollout in the buildings sector.

Implications for Hydrogen Rollout: The rollout of 100% hydrogen to buildings will need significant planning and coordinated implementation. Installation of "Hydrogen Ready" boilers into end-users' properties will need to lead the switchover to hydrogen, probably by several years. Additionally, work package 7 of the Hy4Heat project is reviewing the overall safety case for hydrogen which includes

considering how to manage existing gas pipework within a building and whether other appliances will also need to be checked for hydrogen compatibility, and potentially either replaced or removed.[39]

Ideally a "Hydrogen Ready" boiler would be installed as building owners or occupiers replace an end of life appliance, therefore minimising any additional disruption. However, the required pace of Hydrogen Cluster development and more importantly the need for areas to change in a coordinated process may mean that some end-users will need to replace their boilers prior to the end of their useful life.

In this case, two issues will need to be addressed: Firstly, end-users impacted in this way will need to be financially compensated (or incentivised) for an early boiler replacement. Secondly, the interruption of heat provision may need to be mitigated. Boiler replacement undertaken in the summer months may be manageable for end-users (with appropriate incentives). However, boiler replacements undertaken in winter may be resisted by building occupiers. With the UK heating season typically running from October through March or April (5.5 months) mitigating actions will need to be identified to facilitate the required pace of building conversions. In this circumstance prior installation of a heat pump, to create a hybrid heat system, ahead of the "Hydrogen Ready" boiler installation may enable the heat pump to provide some heat while the boiler is being replaced. Alternatively, seasonal campaigns could be undertaken. H21 envisaged a 6-month rolling plan and implement campaign. Alternatively, boiler replacements could be done in the summer (1- or 2-day's work per boiler) combined with winter hydrogen switchovers (1 hour work per boiler). Either way, this will need to be meticulously coordinated in line with the network planning described in Section 3.2.5.

The energy transition must be completed in 30 years if the 2050 net-zero target is to be met. Historical precedents suggest that this will be extremely challenging without significant Government intervention. For example, loft insulation took about 22 years to be implemented in around 95% of properties. This change was easy to implement, low cost and resulted in almost immediate energy savings for most building occupiers. The installation of condensing boilers is on schedule to take around 25 years from the point at which they were mandated. Other non-mandated changes such as the initial installation of central heating, cavity wall insulation and double glazing took over 50 years to widely implement.[40] Whilst these building renovations all provided significant benefits, they also resulted in substantial expenditure, disruption, or both for building owners / occupiers.

In Section 3.1.3, we described the need for a "low regret" actions for Government to mandate "Hydrogen-Ready" boilers and develop financial support mechanisms to assist and incentivise end-users to make the necessary investments in hybrid systems and other appliances in preparation for a net-zero emission energy supply. In Section 3.2.7 we describe some of the specific policy options available.

[39] https://www.hy4heat.info/wp7

[40] https://event.networks.online/heat/wp-content/uploads/sites/67/2019/05/2.-Phil-Sheppard.pdf

3.3.4 Biomethane Supply via Anaerobic Digestion

Our Pathway anticipates a major expansion of biomethane supply to the gas networks. With easier gas network connections (Section 3.2.1) and increased access to grid capacity (Section 3.2.2) we expect biomethane to increase from 3 TWh in 2018 to 22 TWh in 2030. We assume annual additions of 20 anaerobic digestion plants (averaging 1,000 m^3 capacity per year) in 2020, increasing to 40 plants per year[41] from 2029 onwards. This is in line with current run-rates and stakeholder feedback.

Grow Biomethane from Anaerobic Digestion
Timing: 2020+
Responsible: Biomethane producers / Gas Network Companies / BEIS / Ofgem
Requirements for Success:
- Updates to GS(M)R and CoTER
- Policies to incentivise biomethane production instead of generation of power from biogas

By 2050 we expect biomethane production from anaerobic digestion to be almost 60 TWh. This assessment is based on the research conducted by the Anaerobic Digestion and Bioresources Association (ADBA) and the Committee on Climate Change.[42]

Biomethane, from anaerobic digestion and Bio-SNG (Section 3.4.5), will displace natural gas for end-users outside of the dedicated Hydrogen Clusters (Section 3.4.3). This could occur across GB but will be focused in South and Central England and large areas of Wales. Biomethane production within areas that will eventually convert to hydrogen (primarily cities with a significant industrial base and access to the North Sea or Morecambe Bay natural gas resources) will need to be aggregated and supplied to transport hubs to provide Bio-CNG and Bio-LNG for road and shipping transport (Section 3.5.3).

Practically all biomethane will be a direct replacement for natural gas, although with a lower calorific value. End-users who are supplied with biomethane will likely not notice any direct difference in their energy supply and their gas boilers will not need a direct like-for-like replacement.

3.3.5 Demonstrate Bio-SNG Production Technology

The CCC 'Global Governance & Innovation' scenario estimates 285 TWh of available solid biomass feedstocks, suitable for thermal gasification (to produce Bio-SNG or liquids fuels through the Fischer–Tropsch process), power generation or use in industry for heat.

Imports make up 54% of the total (155 TWh), with the balance (130 TWh) UK feedstocks.[43] Our modelling estimates that around 173 TWh of this feedstock is used to produce 121 TWh of Bio-SNG, assuming a conversion efficiency of 70%.

Prove Commercial Feasibility of Bio-SNG
Timing: 2020-2030
Responsible: Project and Technology Developers / BEIS / Ofgem / Gas Network Companies
Requirements for Success:
- Innovation funding to support technology development
- Business models and long-term revenue support policies to support extensive deployment of low carbon and renewable gas production projects for grid injection post RHI closure

[41] This includes new dedicated biomethane plants and existing anaerobic digestion plants currently configured to produce power transitioning to biomethane once tariffs come to an end.

[42] We used the ADBA estimates for all feedstocks, except for food waste, landfill gas and sewage sludge, which are instead based on an average of the CCC "low" / "high" estimates. We note that there is a significant difference between ADBA and the CCC for the potential manure estimate (20 TWh compared to 3.1 TWh), which we assume results from a lower applied collection rate. We have used the ADBA value as it is in-line with estimates that Navigant has recently provided for ENTSO-G.

[43] 93 TWh UK forestry, crops and residues, and 37 TWh waste feedstocks (waste wood and MSW). We reduce the UK forestry, crops and residues potential by 4 TWh to account for the straw that is used in anaerobic digestion.

The GoGreenGas[44] project (backed by Cadent, Advanced Plasma Power and Progressive Energy) in Swindon is developing Bio-SNG production technology plants using biomass as feedstock. A 50 kWh Bio-SNG pilot plant using refuse derived fuel (RDF) has been built and successfully operated. GoGreenGas are now constructing a 4 MW Bio-SNG plant, also in Swindon, which is expected to be completed in around 2020. Progressive Energy and Peel Environmental are planning a 42 MW Bio-SNG plant near Ellesmere Port in Cheshire and this facility is anticipated to be operational in 2023.[45] The project will use waste wood and RDF feedstocks.

The two proposed plants both intend to produce Bio-SNG for use as a road transport fuel, being supported under the Renewable Transport Fuel Obligation (RTFO). The imminent closure of the RHI in March 2021 effectively rules out further Bio-SNG projects being developed for anything other than road transport beyond this time. Consideration on how large scale gas injection to grid for heat can be incentivised post-RHI therefore needs to be provided.

It is likely that existing Bio-SNG plants could also be converted / retrofitted to hydrogen production relatively easily and cheaply, requiring alternative catalysts and control systems, but able to use largely the same physical equipment. This concept has been explored by GoGreenGas, who have performed pilot-scale testing of biohydrogen production using their 50 kWh Bio-SNG plant.[46]

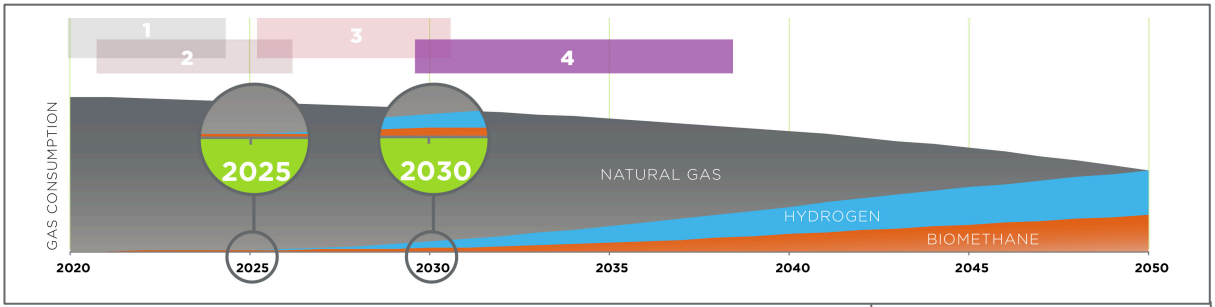
Thermal gasification to produce Bio-SNG is in the early commercial stage of development. Although there are around 50 to 100 biomass and/or waste gasifiers in operation globally, only a small subset of these are producing Bio-SNG. Further development and demonstration projects will be required so that Bio-SNG can be commercialised by 2030.

[44] https://gogreengas.com/

[45] https://www.peelenvironmental.co.uk/news-blog/2019/3/6/progressive-energy-submits-application-for-150m-renewable-energy-facility-at-protos

[46] GoGreenGas (2017). Biohydrogen: Production of hydrogen by gasification of waste. https://gogreengas.com/wp-content/uploads/2015/11/Biohydrogen-Cadent-Project-Report-FINAL-3.pdf

3.4 Expanding the Demand Base



Expanding the Demand Base

Hydrogen use extends to commercial and residential consumers near the first hydrogen projects, initially via low blends (up to 20%) but developing into 100% hydrogen clusters
Consumers in other regions continue to receive natural gas, with rising blends of biomethane

- Implement programme to switch more consumers to hydrogen
- Use hydrogen blending for flexible network management
- Deploy large-scale hydrogen storage to manage peaks
- Increase biomethane supply including via bio-SNG
- Continue improving energy efficiency throughout GB

To facilitate the expansion of hydrogen use, hydrogen will need to be blended in to selected parts of the gas networks, in part to help manage the differences in hydrogen supply and demand as projects for production and use of hydrogen develop with different timings.

This part of the Pathway also considers the development of Hydrogen Clusters and the need to implement large scale hydrogen storage to manage seasonal demand fluctuations driven by the buildings sector.

We have identified a number of locations where Hydrogen Clusters can be developed based on:

- The availability of a natural gas supply;
- The potential access to CCUS facilities;
- Substantial hydrogen demand (current and potential); and
- Access to potential hydrogen storage facilities.

Further, once commercially proven at scale we anticipate the deployment of Bio-SNG will accelerate from 2030. By 2050, Bio-SNG will provide double the quantity of biomethane than that produced from anaerobic digestion.

3.4.1 Hydrogen Blending for Flexible Network Management

The initial development of hydrogen production and utilisation in our Pathway is based on the conversion of anchor end-users to low carbon hydrogen. This will likely result in very rigid supply chains with limited flexibility and effectively this would force the initial hydrogen schemes to be developed as integrated gas production, supply and use projects. This integrated approach could create significant barriers to project financing and execution.

Blending of Hydrogen into Gas Networks
Timing: 2025+
(or 2024 if using hydrogen demonstration project)
Responsible: Project and Technology Developers / BEIS / Ofgem / Gas Network Companies
Requirements for Success:
- Updates to GS(M)R and CoTER
- Innovation funding to support technology development
- Business models and policies to support CCUS and extensive deployment of low carbon and renewable gas production

Having the potential to blend hydrogen into the gas networks would provide some flexibility to use excess hydrogen production at times when there is insufficient local demand, either due to the limited capacity of any small-scale hydrogen storage to manage any oversupply or, potentially more importantly, due to differences in timing between when the low carbon hydrogen supply comes on line and when the anchor end-user is ready to take that hydrogen. The capability to blend hydrogen into the low-pressure distribution networks could also enable hydrogen production to be planned to start ahead of the anchor end-user projects.

Most end-users on the low-pressure distribution networks are likely to use gas for heating through boilers. Current boilers are required to be compatible with up to 20% (volume) hydrogen, providing the flexibility to blend hydrogen to a significant level that these end-users can likely accept. The key issue limiting blending of hydrogen at this stage of the Pathway development will be to ensure that combined cycle gas turbine (CCGT) power plants or industrial facilities that are highly sensitive to gas quality would not be impacted by any hydrogen blending.

Our Pathway does not anticipate extensive blending of hydrogen into the NTS at the early stages of Hydrogen Cluster development, although this may be possible, at small scale, if proven by the HyNTS and related projects (Section 3.1.2). The caveats about supplying hydrogen to CCGTs and gas quality sensitive industrial users would be also applicable to any hydrogen blending into the NTS.

3.4.2 Creating Hydrogen Clusters

We envisage that Hydrogen Clusters will develop around the initial anchor end-users and hydrogen production projects. To successfully develop, the Hydrogen Clusters will need to meet several criteria:

A Natural Gas Supply: At the start of the Hydrogen Cluster development the majority of the hydrogen production is expected to be Blue, i.e. through the reforming of natural gas, either Steam Methane Reforming (SMR) or Auto Thermal Reforming (ATR). Therefore, a supply of natural gas will be required to support the Hydrogen Cluster development. Our Balanced Scenario assumes most hydrogen production in 2050 will still be by reforming of natural gas, however natural gas will no longer be consumed by end-users. Therefore, to secure a long-term source of natural gas, the production of Blue Hydrogen will need to be at, or near to, gas network entry points such as gas terminals connected to the North Sea or import pipeline systems.

Access to CCUS: Both natural gas reforming processes (SMR and ATR) result in the production of CO_2. These hydrogen production projects will therefore need access to carbon storage facilities. These are most likely to be developed in the North Sea, along the east coast or in Morecambe Bay.

Substantial Hydrogen Demand Potential: Refinery and chemicals plants are significant users of hydrogen for desulphurisation and other processes. Hydrogen is also required as a feedstock for fertiliser manufacture. Any of these could be initial anchor end-users for a Hydrogen Cluster. There must also be the potential to expand hydrogen use beyond the initial anchor end-users to other industrial and transport companies, and ultimately into the building sector.

Potential for Access to Hydrogen Storage: As the Hydrogen Cluster expands, particularly into the building sector, demand will become highly seasonal, just as natural gas demand is seasonal now. Therefore, the Hydrogen Cluster will need access to large scale hydrogen storage facilities such as the salt caverns in North Yorkshire, Teesside and Cheshire.

3.4.3 Hydrogen Clusters

We have identified several locations that meet these criteria and where a Hydrogen Cluster could be developed.

The overall policy, commercial framework and regulations for the deployment of hydrogen to industry, transport and buildings will need to be set out early in the Pathway (Section 3.1.3) by Government and Ofgem. However, when each Hydrogen Cluster starts and the rate at which it expands will depend largely on local factors. Ideally, the Hydrogen Clusters will develop in parallel.

The availability of CCUS is likely to be the key consideration. For that reason, Hydrogen Clusters with direct access to potential CCUS sites in North Sea or Morecombe Bay are likely to lead. The scale of local demand for hydrogen from industry and when this demand emerges will vary from Cluster to Cluster.

Development of Hydrogen Clusters
Timing: 2028+
Responsible: BEIS / Ofgem / Gas Network Companies / Hydrogen producers and storage companies etc.
Requirements for Success:
- Business models and policies to support CCUS and extensive deployment of low carbon and renewable gas production
- Effective communication of energy transition
- Incentives and support mechanism for building owners / occupiers to install hydrogen ready appliances
- Hydrogen ready appliance conversion
- Enough trained hydrogen gas fitters and installers
- Detailed network plan and programme for conversion
- Large scale hydrogen storage

The gas network companies will play a significant role in orchestrating the Hydrogen Cluster development, in particular supporting industry to prepare for and implement the changeover to hydrogen by providing direct technical support and assisting with hydrogen trials.

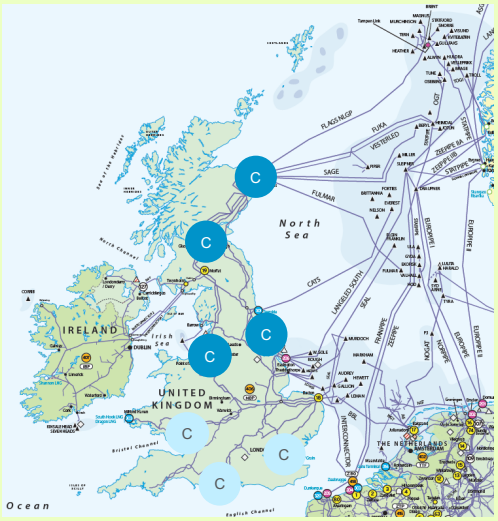
Scotland (Aberdeen & Grangemouth): Hydrogen Clusters at Aberdeen and Grangemouth would have access to natural gas from the North Sea through existing pipelines from the St Fergus gas terminal.

CCUS could also be accessed via the North Sea, predominantly offshore Aberdeen (e.g. project Acorn). The CCUS facilities would require new offshore infrastructure and new, or repurposed, connecting pipelines.

In Aberdeen, SGN has been assessing hydrogen opportunities through its Aberdeen Vision project. Grangemouth has a world-scale refinery, chemical facilities and associated industry.

North East of England (Teesside / Immingham): Teesside is home to the Central Area Transmission System (CATS) gas processing terminal that receives gas from the central North Sea.

CCUS access could be provided by facilities within the central or southern sections of the North Sea.



C H_2 Cluster – *Direct CCS access* C H_2 Cluster – *Limited CCS access*
Map: ENTSOG - The European Natural Gas Network

Teesside is home to two refineries, multiple chemicals plants and other heavy industry.

North West of England (Liverpool / Manchester): Hydrogen Clusters in Liverpool and Manchester would be located between the Rampside (Barrow in Furness) and Point of Ayr (Flintshire, Wales) gas terminals, both of which receive natural gas from Morecambe Bay.

CCUS access could be provided by new facilities within Morecambe Bay and new, or repurposed, connecting pipelines.

Liverpool and Manchester have large industrial bases, the Stanlow refinery is close by, and hydrogen is also currently produced at CF Fertiliser and Ineos Chlor.

Other Hydrogen Clusters could be developed in Wales and Southern England, but these would be subject to identifying suitable mechanisms to store CO_2 as CCUS may not be readily accessible locally. An alternative approach for developing these southern Hydrogen Clusters may be to utilise Green Hydrogen (electrolysis) rather than Blue (natural gas reforming). Use of electrolysis for hydrogen production would remove the need for CCUS access.

Southampton: A cluster close to Southampton and the Fawley refinery could be an option. CCUS may be possible southwest of the Isle of Wight.

Bristol and South Wales: The opportunity to develop a Hydrogen Cluster around the South Wales-Bristol area is being evaluated. There is significant potential for industrial demand in this region. However, there is no direct access to CCUS. CO_2 from natural gas reformers would need to be piped to a potential CCUS site south west of Ireland, or otherwise shipped to a CCUS facility in Morecambe Bay that would be developed for the Liverpool / Manchester Hydrogen Clusters, or exported to a receiving facility overseas.

Thames Estuary: A Hydrogen Cluster may also develop around East London, potentially starting with SGN's Cavendish project based at Isle of Grain. Like the Bristol and South Wales opportunity, an East London Cluster would have limited access to potential CCUS facilities.

3.4.4 Large-Scale Hydrogen Storage

Implementation of Large-Scale Hydrogen Storage
Timing: 2020 planning > 2028+ start-up
Responsible: BEIS / Ofgem / Hydrogen storage companies / Gas Network Companies
Requirements for Success:
- Business models and policies to support hydrogen storage
- Network and hydrogen storage planning and preparation (including cushion gas injection)

As Hydrogen Clusters develop and expand, there will be an increasing need for hydrogen storage.

Currently, GB's natural gas storage is a small proportion of gas consumption. The largest long-term storage facility at Rough in the North Sea was recently closed by its operator, Centrica. Following the closure of the Rough facility, the required seasonal natural gas flexibility is provided through a combination of the remaining seven gas storage facilities, liquefied natural gas (LNG) imports, pipeline imports from Norway and continental Europe as well as some variability in domestic gas production. Two more natural gas storage facilities are anticipated to come online by the end of 2019.

It is not certain that these supply flexibility options will be available for hydrogen. LNG terminals are not able to import hydrogen so other solutions, such as importing ammonia, would be required. The countries that currently supply GB with natural gas by pipeline (Norway, Belgium and the Netherlands) may not have sufficient hydrogen supply capacity to fully meet GB's seasonal demand peaks.

Development of a Hydrogen Cluster into the buildings sector would require large scale hydrogen storage to be developed to match the seasonal demand profile of building heat requirements, including provision of sufficient capacity to meet peak demand. The storage facility could be a salt cavern[47] or a decommissioned oil and gas reservoir. A hydrogen storage facility will usually require a large "cushion gas" volume to be injected to enable the storage facility to work effectively. A hydrogen storage facility is anticipated to take between three to seven years to become operational depending upon its size, the type of storage structure and the specific requirement for cushion gas. Due to the potentially long development period, it is important that planning and implementation for the hydrogen

[47] There are around 30 large salt caverns in use in the UK spread geographically in several locations, including Cheshire, East Yorkshire and Teesside. These collectively store around 10,000 GWh of natural gas. Many of these could potentially be re-used for hydrogen storage or new caverns constructed. https://www.atkinsglobal.com/en-gb/projects/eti-salt-caverns-study

storage is prioritised early (Section 3.2.5) in the process of creating the Hydrogen Cluster otherwise expansion may stall, pending storage availability.

Also as described in Section 3.2.5, Government support will be required to facilitate investment in hydrogen storage so that the required facilities are online by the time the Hydrogen Clusters are expanding into the buildings sector.

3.4.5 Bio-SNG Commercialisation

In our Pathway, we expect that Bio-SNG production will only develop at significant scale from 2030. Given the constraints of UK biomass supply, and in particular waste feedstocks, we anticipate that Bio-SNG plants will need to rely on imported biomass if the technology is to develop to significant scale.

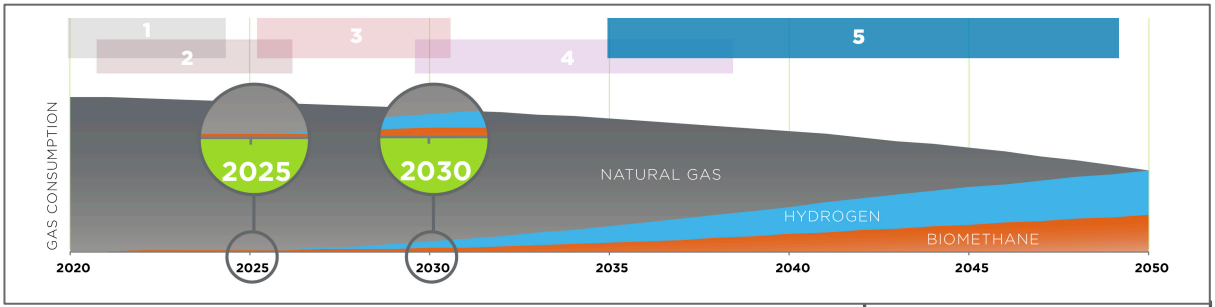
We prioritise using the biomass feedstock for Bio-SNG rather than for electricity generation as burning biomass wood pellets typically achieves a conversion efficiency of 30-35%. In comparison, Bio-SNG plants (once commercialised) are likely to realise a conversion efficiency of up to 70%.

Large Scale Deployment of Bio-SNG
Timing: 2030+
Responsible: Project and Technology Developers / BEIS / Ofgem / Gas Network Companies
Requirements for Success:
- Successful demonstration of commercial / technical feasibility
- Business models and policies to support extensive deployment of low carbon and renewable gas production projects
- Successful deployment of CCUS for negative emissions

Additionally, Bio-SNG plants can also be more readily enabled for CCUS as the CO_2 stream is removed during the production process and the availably of these “negative emissions” helps to offset residual emissions elsewhere in our Balance Scenario. We anticipate that around half of the Bio-SNG facilities will be fitted with CCUS by 2050.

As a consequence of the use of imported feedstocks and the application of CCUS, most Bio-SNG plants are expected to be located close to sea ports where the biomass feedstock will be imported and also importantly where there will be access to CO_2 transportation and storage facilities. Bio-SNG plants using RDF as a feedstock will be smaller-scale and likely located in metropolitan areas, close to the feedstock source.

3.5 Increasing Low Carbon Gases



Initially, the Hydrogen Cluster development will be largely based on the production of Blue Hydrogen. Over time, with expanding renewable generation, there will be an increase in potential curtailment of these renewable generation assets. This will create opportunities for the growth of Green Hydrogen. These Green Hydrogen production facilities would not need access to CCUS, providing freedom in the plant location, potentially near to hydrogen demand, to aid network configuration planning and cluster expansion.

This expansion of the Hydrogen Clusters would ultimately lead to some of them merging to form larger Hydrogen Zones. At this point the NTS could play an important role creating links across the large Hydrogen Clusters, or Zones, between multiple production, storage and network hubs.

The use of low carbon and renewable gases (particularly biomethane) in the transport sector is an important part of the Balanced Scenario. With the creation of the Hydrogen Zones and increasing regionalisation of gas supply into hydrogen and biomethane areas, mechanisms will be needed to ensure biomethane supply to transport hubs is maintained and secured.

Increasing Low Carbon Gases

Hydrogen clusters spread and connect to become extensive hydrogen zones, enabled by an evolving, carefully managed National Transmission System (NTS)
Greater volumes and diversification of low carbon gas supply as more production methods mature technically and economically

- Expand supply and demand to form larger hydrogen zones and biomethane zones
- Increase green hydrogen supply via electrolysis using renewable power
- Maintain biomethane availability at transport hubs all over GB, including within hydrogen zones
- Continue joint network planning to manage the transition, including reconfiguring the NTS

3.5.1 Changing Hydrogen Production Profile

As the Hydrogen Clusters develop over time, our Pathway anticipates that the profile of hydrogen production will change.

Initially the majority of hydrogen production will be Blue (through reforming of natural gas). These production facilities will need to be located where there is a supply of natural gas, access to CCUS and demand for hydrogen.

Some limited Green, electrolyser-based, hydrogen production will likely occur as Hydrogen Clusters develop, however we expect Green Hydrogen production to be modest until the late 2030s – prior to that, renewable energy systems will primarily be utilised to displace fossil fuels from the power generation sector.

Widespread Deployment of Green Hydrogen
Timing: 2035+
Responsible: Project and Technology Developers / BEIS / Ofgem / Gas Network Companies
Requirements for Success:

- Innovation funding to support technology development
- Business models and policies to support extensive deployment of low carbon and renewable gas production projects
- Cost reductions for electrolysis
- Significant displacement of fossil fuels from power generation achieved
- Large scale hydrogen storage

As the capacity of wind and solar energy systems increases to replace natural gas generation there will be an increase in “curtailed” generation – when renewable power generation exceeds demand. Battery storage systems will utilise some of this potentially curtailed power. Our Pathway assumes

curtailed renewable power is modest until the late 2030s, when low carbon generation power will come close to replacing natural gas generation sources.

Green Hydrogen through dedicated power to gas projects is also an important part of our Pathway. Most power to gas will be through offshore wind but there will be some solar power electrolysis projects as well. This hydrogen production technology does not need access to a natural gas supply, or more importantly to CCUS facilities. Therefore, electrolysis plants can be co-located with demand (and potentially the renewable electricity source to reduce transmission losses) rather than having to be located close to the gas feedstock and CO_2 storage as is case for natural gas reforming plants, provided sufficient electricity network capacity exists. This location flexibility could be used to aid gas network planning and may avoid some gas network reinforcement during the transition to a 100% low carbon and renewable gas network.

Our Pathway anticipates that hydrogen production in 2050 will be approximately two-thirds Blue (natural gas reforming) and one-third Green (by electrolysis). The renewable power dedicated to Green Hydrogen will be 19 GW of offshore wind and 8 GW of onshore solar PV.

3.5.2 Creating Larger Hydrogen Zones

As the Hydrogen Clusters develop and grow, natural gas use will be displaced from end-users' equipment and appliances. Natural gas supply will become increasingly focused on supplying methane reforming facilities to produce Blue Hydrogen.[48]

Expanding Hydrogen Clusters to Combined Zones
Timing: 2035+
Responsible: Hydrogen Producers / Gas Network Companies / Equipment Manufacturers
Requirements for Success:
- Detailed network plan and programme for conversion
  - Utilisation of NTS for hydrogen
  - Aggregation of biomethane for supply to transport hubs
- Effective communication of energy transition
- Incentives and support mechanism for building owners / occupiers to install hydrogen ready appliances
- Hydrogen ready appliance conversion
- Enough trained hydrogen gas fitters and installers
- Large scale hydrogen storage

The Hydrogen Cluster development will require the relevant parts of gas networks to convert to 100% hydrogen. This network conversion will include parts of the NTS, particularly as the Hydrogen Clusters expand geographically well beyond the initial anchor end-users. The conversion of parts of the NTS will depend upon the successful trials being undertaken by HyNTS and related projects (Section 3.1.2).

Our Pathway anticipates that the gas quality within the gas networks will need to reflect that acceptable to end-users, i.e. a blend up 20% (volume) or 100% hydrogen. This constraint and the expansion of the Hydrogen Clusters will inevitably require some network reinforcement (either temporary or permanent) to ensure continuity of supply security for end-users, irrespective of whether they are using hydrogen or (bio)methane. Detailed network planning (Section 3.2.5) will be required to identify options to address supply security and the mechanisms to reinforce the gas networks as low carbon and renewable gases displace natural gas.

In Chapter 5 we consider the impact successful implementation of gas separation technologies would have for the gas networks. In particular, we review how these technologies could significantly simplify network planning over the course of the Pathway and provide the capability to use the NTS to transport a variable blend of bio(methane) and hydrogen, whilst still enabling the gas networks to deliver separate (bio)methane or hydrogen supply to end-users.

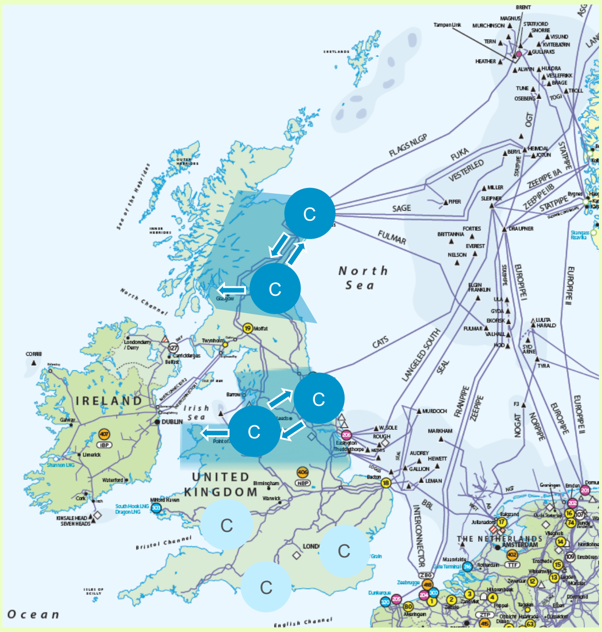
As hydrogen supply expands further, our Pathway anticipates that some of the initial Hydrogen Clusters merge to form larger Hydrogen Zones. At this point in the Pathway development we anticipate that Green Hydrogen (production by electrolysis) will also be growing rapidly (Section

[48] Available technologies are Steam methane reforming (SMR) and Auto thermal reforming (ATR). See Appendix B for further details.

3.5.1). The increasing use of both curtailed renewable power as well as dedicated electrolysis projects for hydrogen production will assist the development of the Hydrogen Zones as these hydrogen production facilities would not be constrained by the need to be located near to both a natural gas supply and CCUS facilities. The merging of the Hydrogen Clusters into larger Zones will also increase the benefits for converting parts of the NTS to hydrogen, providing connections across the Hydrogen Zone between multiple hydrogen supply sources, storage and network hubs. This should also enable the creation of commercial markets for hydrogen in these zones, facilitating widespread trading of hydrogen rather than the point to point commercial arrangements that will be required with the initial anchor projects.

North East – North West England: The H21 North of England project envisages hydrogen supplied across this region. The expansion of the Teesside / Immingham as well as Liverpool / Manchester Hydrogen Clusters would likely mirror the H21 North of England approach.

Scotland: In Scotland our Pathway anticipates Hydrogen Clusters developing around both Aberdeen and Grangemouth. These Hydrogen Clusters are 80 miles apart and we would expect these to merge quickly. This larger Scottish Hydrogen Zone would further expand to cover Edinburgh to the east and Glasgow to the west.



C H_2 Cluster – *Direct CCS access*

H_2 Zones

C H_2 Cluster – *Limited CCS access*

Map: ENTSOG - The European Natural Gas Network (2017)

3.5.3 Biomethane in Transport

Shipping: The shipping industry is currently having to meet the challenge of reduced sulphur and other emission restrictions. In April 2018, the International Maritime Organisation (IMO) set a target to halve total greenhouse gas emissions of the global shipping sector in 2050 compared to 2008 and outlined a vision to fully decarbonise shipping between 2050 and 2100.[49] We assume full decarbonisation of GB shipping (meaning ships fuelling in GB) will be achieved in 2050.

Battery electric ships are almost twice as efficient than ships with an internal combustion engine, hydrogen fuel cells have a 30% higher efficiency and Bio-LNG ships are around 13% less efficient.

Biomethane Supply for Transport
Timing: 2025+
Responsible: Gas Network Companies / BEIS / Ofgem
Requirements for Success:
- Detailed network plan and programme for conversion
  Aggregation of biomethane for supply to transport hubs
- Incentives and support mechanism for transport companies to convert low carbon fuels
- Alignment with International / EU ship fuel and EU road fuel developments

[49] The International Maritime Organisation (IMO) is a specialised agency of the United Nations for regulating shipping.

Due to its high efficiency, electricity is the most cost-optimal shipping fuel, but its use is limited to short routes due to low energy density of batteries and so we assume that it is only possible to 100% electrify domestic shipping, characterised by smaller ships and shorter routes, for example ferries with regular schedules and time for charging while embarking or disembarking. About a third of intra-EU shipping is assumed to have similar characteristics as domestic shipping and can also be fully electrified. Several European countries are testing battery electric ships for domestic shipping. For example, the Norwegian ferry sector will operate 60 battery electric ships in the next few years.[50]

There have been several tests for hydrogen fuel cell ships, but no commercial application yet. Aside from small ferries and demonstration projects there are hardly any commercial hydrogen-fuelled ships. In 2017, Swedish Viking Cruises announced plans to build the first hydrogen-fuelled cruise ship.[51]

International shipping on long distance routes, often without regular schedules, requires a uniform fuelling option with a fuel that is globally available in sufficient quantities. Deploying multiple fuelling options would be costly both from vessel technology and infrastructure perspectives. As fuel cost is the main driver, it is expected one fuel will dominate for international shipping in 2050.

A primary emission reduction solution currently being implemented by ship owners and operators is to move to liquefied natural gas (LNG) to address the current sulphur and nitrogen emission standards. Many GB (and global) ports are expected to install LNG bunkering facilities, particularly ports located in designated emission control areas (ECA) such as those covering the North Sea, Baltic and English Channel. Other ECAs cover large parts of the US west and east coasts. China has set up three ECAs near major ports such as Hong Kong and Shanghai. ECAs are being considered for the Mediterranean, and for the coasts of Japan and Australia.

For long distance routes, Bio-LNG is the most competitive low carbon fuel in 2050, despite its lower efficiency compared to biodiesel.[52]

The fuel choice for international shipping will also impact the fuel choice for intra-EU shipping, as international shipping will drive the fuelling infrastructure. Therefore, the proportion of intra-EU shipping that is not electrified will use Bio-LNG.

Road Transport: In the light vehicle segment (cars and light commercial vehicles), and in public transportation (buses), EVs are expected to play a major role. Hydrogen will also have a role for fuelling buses, in part driven by air quality concerns. Several cities are already trialling this technology on single-decker buses, including Aberdeen, Brighton and London. Aberdeen also recently became the first city in the world to launch a fleet of hydrogen powered double-decker buses, with London, Birmingham, Dundee and Brighton due to follow.[53]

We expect that the heavy road freight fleet will operate on several fuels: electricity (either through battery or catenary wires), biomethane (either in compressed or liquefied form) and hydrogen (FCEV). The fuel choice will likely be dictated by typical distance travelled, type of role the vehicle / fleet is to fulfil, and also the intra-European developments in freight transport. In our model, hydrogen is forecast to provide nearly half the heavy road freight fuel, with a third being through Bio-CNG and the remainder of the fleet being electrified.

Deploying biomethane in heavy road freight is gaining significant interest among major fleet operators. For example, the John Lewis Partnership has pledged to run its entire fleet of over 500 trucks used for store deliveries on biomethane by 2028. Longer-term we expect a transition to hydrogen powered trucks, as FCEV technology costs fall.

[50] DNV GL (2018). Maritime forecast.
[51] The Maritime Executive (2017). Worlds First Hydrogen-Powered Cruise Ship Scheduled. https://www.maritime-executive.com/article/worlds-first-hydrogen-powered-cruise-ship-scheduled
[52] We acknowledge that it is feasible that other solutions may arise for decarbonising the shipping sector in the period to 2050, for example the adoption of hydrogen or ammonia as fuels. However, these alternative options are not included in our Pathway.
[53] https://www.pressandjournal.co.uk/fp/news/aberdeen/1799344/world-first-for-aberdeen-as-city-orders-15-double-decker-hydrogen-buses/; https://www.theguardian.com/uk-news/2019/may/10/london-to-have-world-first-hydrogen-powered-doubledecker-buses

The Renewable Transport Fuel Obligation (RTFO), the main policy instrument designed to promote renewable fuels in transport, has recently been amended to broaden the fuels types covered. From 1 January 2019, a separate dedicated sub-target for so-called renewable 'development fuels' (which include hydrogen and substitute natural gas) was introduced. Fuels that count towards the development fuel target are further incentivised through the award of double 'development fuel' certificates (RTFCs). Importantly, the RTFO also now sets out a target trajectory to 2032, providing long-term stability to the market.[54]

In addition, the GBP20m Future Fuels for Flight and Freight Competition, launched in April 2017, aims to increase domestic production of advanced low carbon fuels capable of reducing emissions from the aviation and heavy goods sectors. Two of the seven shortlisted projects specifically target the production of Bio-SNG.[55]

Transport Fuel Supply: Electrical charging for heavy freight vehicles, passenger cars and other battery vehicles is expected to be widely available across GB well before 2050.

Hydrogen refuelling facilities will be available within the Hydrogen Clusters from the main network supply. Outside of the Hydrogen Clusters, hydrogen refuelling stations will need electrolysers on, or near to site, along with hydrogen storage facilities.

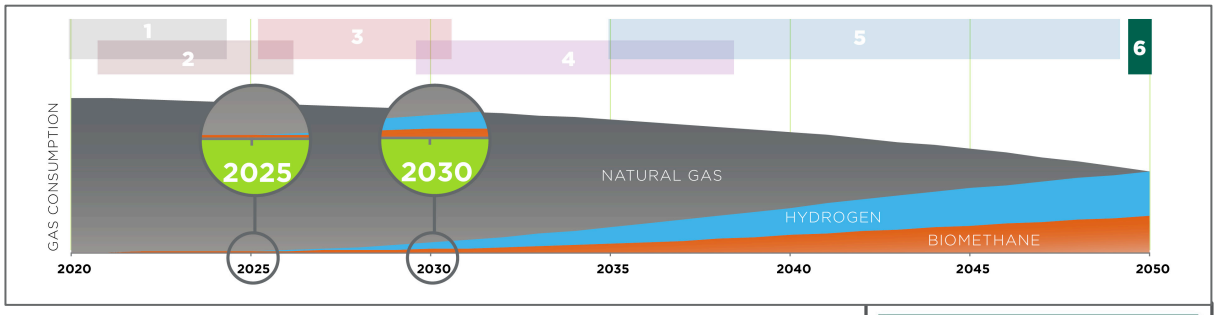
Provision of Bio-LNG for international shipping is also likely to be reasonably straightforward and cost effective. As described in Section 3.4.5, we anticipate that most Bio-SNG plants will be located near to GB's major ports as the required biomass feedstock for these facilities is likely to be imported. Half of the Bio-SNG plants will be equipped with CCUS and this provides another driver for Bio-SNG to use coastal locations with access to the North Sea or Morecambe Bay. These Bio-SNG plants (together with small-scale liquefaction) will be ideally located to provide the Bio-LNG required for international shipping. Other ports that do not have a nearby Bio-SNG facility would be supplied by LNG bunkering vessels, loading from a port equipped with a Bio-SNG plant and small-scale liquefaction.

Providing Bio-CNG for road freight use throughout GB will be somewhat more complex. In large parts of southern England and most of Wales, where we anticipate that biomethane will be the predominate low carbon and renewable gas, Bio-CNG will be straightforward to supply. However, in Northern England, parts of Wales and large parts of Scotland, we anticipate that hydrogen will eventually be the predominant fuel in the gas networks. In these areas, biomethane will still be required in the key transport zones such as around the M1, M6, M62, M8 and M9 etc. Local biomethane supply from anaerobic digestion facilities or Bio-SNG plants using RDF will need to be aggregated and transported by truck as CNG, or possibly transported to the refuelling facilities by the gas networks where they continue to be used for methane.

[54] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/694277/rtfo-guidance-part-1-process-guidance-year-11.pdf

[55] https://www.gov.uk/government/news/government-funding-boost-for-low-carbon-fuels-development

3.6 100% Low Carbon Gases



100% Low Carbon Gases

Low carbon gases fully integrated across the GB energy system, with distinct regional solutions

All gas end-users are supplied with hydrogen and/or biomethane, the principal type varying by region

Natural gas no longer used, unless abated with CCUS for blue hydrogen production

Net-zero energy system achieved in 2050

The role of the gas networks in 2050 will be different to that which they currently fulfil. The energy supplied by low carbon and renewable gases to end-users will be around 50% lower in 2050 than that provided by natural gas today. Peak daily flows will also decrease, but only by 40%. Natural gas will still be required at the network peripheries to supply blue hydrogen production facilities.

The networks will need to transport hydrogen and biomethane, and in some instances a blend of the two. This changing mix of natural and low carbon and renewables gases will create significant complexity for the gas networks. This complexity is likely to be greatest during the middle of the transition to a net-zero energy system. Whilst the gas networks have adequate capacity to handle the total peak flows of gas (natural plus low carbon and renewable), a requirement to transition from a 20% maximum blend of hydrogen to 100% hydrogen within the clusters will challenge network capacity and operations.

Biomethane: Biomethane, produced through anaerobic digestion or Bio-SNG will have an increasingly important role in GB's energy system. We anticipate that biomethane production will be largest and more concentrated in Southern GB and more distributed throughout the northern England and Scotland. Biomethane production will be driven by a large number of relatively small facilities. Approximately 1,500 "farm scale" anaerobic digestion plants connected to the gas network by 2050.

Bio-SNG production facilities will be large scale but will also be geographically dispersed, with around half being equipped with CCUS facilities and therefore requiring access to carbon storage facilities in the North Sea or Morecambe Bay. The use of Bio-CNG in heavy road freight transport and Bio-LNG for international shipping will require the provision of biomethane across GB.

Hydrogen: We expect that hydrogen will marginally provide the largest quantity of low carbon and renewable gas supplied to end-users. Our Pathway anticipates that hydrogen production will start, primarily through natural gas reforming, in several specific locations with a natural gas supply, access CCUS facilities or export, potential to access hydrogen storage and significant industrial demand. Hydrogen production and use will expand, with the Hydrogen Clusters merging to form larger Hydrogen Zones.

Natural Gas: In our Balanced Scenario natural gas has a continuing, although diminished, role in the energy system. Between now and 2050 natural gas will continue to be used by some industry, power generators and buildings, although in ever decreasing quantities over time. By 2050 natural gas use by end-users, including for power generation, will have been eliminated. Natural gas will continue to be used in methane reforming to produce hydrogen. Consequently, natural gas will likely be constrained to the extremities of the gas networks, as the methane reforming facilities will probably be located close to the current North Sea / Morecambe Bay gas terminals for natural gas supply (and CCUS access). The requirement for natural gas in 2050 is equivalent to GB's current domestic gas production, around 270 TWh. With new natural gas finds in the North Sea continuing (CNOOC's Glengorm project east of Aberdeen this year and Total's Glendronach discovery West of Shetland

made in 2018) there is a reasonable prospect that GB could be self-sufficient in natural gas. As hydrogen production moves increasingly towards electrolysis the need for natural gas after 2050 is likely to decline.

Carbon Dioxide (Storage or Utilisation): Hydrogen produced through natural gas reforming will result in the production of CO_2 that will require storage or utilisation. CCUS will also be applied to Bio-SNG plants and biomass power generation for negative emissions. Industry will also utilise CCUS to address emissions. The gas networks, specifically parts of the NTS, could be repurposed to transport CO_2 for storage in salt caverns or depleted oil and gas reservoirs. However, it is likely that most CO_2 infrastructure will be developed by the CCUS projects rather than the gas networks.

3.6.1 Role of Gas Interconnections

The GB gas networks currently have multiple connections to global gas supply. GB has pipeline connections to the Netherlands, Norway and Belgium, together with three world scale LNG import terminals (South Hook and Dragon at Milford Haven and Isle of Grain in Kent). A fourth LNG terminal in Teesside was decommissioned in 2015. Together these facilitate import of roughly half of GB's gas requirements. Along with GB's gas storage facilities, these pipeline and LNG import facilities also provide the gas networks mechanisms to manage peak winter gas demand. These interconnections play a fundamental role in the energy security of GB.

GB is also connected to both Northern Ireland and the Republic of Ireland, providing the majority of gas supply on the island of Ireland. As GB, Northern Ireland, the Republic of Ireland and continental Europe move towards energy system decarbonisation, the role of gas and speed of the transition may be different in these jurisdictions. For example, the type of gas, or blend of gases, may be different at either end of a pipeline at any point in time over the next 30 years as the transition to a low or net-zero emission target is implemented differently or at different speeds in each country.

This issue will require a pan-European solution that is beyond the scope of this report. However, the role of the gas interconnection infrastructure is an important issue that will need careful coordination with our European neighbours.

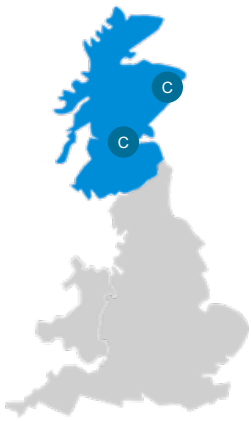
3.6.2 Regional Summaries

Across GB both hydrogen and biomethane will be widely adopted in industry, buildings and transport and both gases will be used as fuel for peak power generation. These changes will be accompanied by a widespread rollout of hybrid heat systems and insulation improvements in buildings across GB.

Scotland

We anticipate that hydrogen production will develop around two potential Hydrogen Clusters in **Aberdeen** and near **Grangemouth**. Both locations have potential demand for hydrogen in industry or transport and available natural gas supply for reforming to produced hydrogen. CCUS facilities could be accessed from Aberdeen through offshore projects, such as the Acorn CCS project. The two Hydrogen Clusters would merge and eventually encompass the cities of Edinburgh and Glasgow. Virtually all of Scotland's gas users will convert to hydrogen.

There will be biomethane production in Scotland through anaerobic digestion and Bio-SNG. This biomethane will be utilised within the transport sector for heavy road freight as Bio-CNG and for international shipping at Scotland's major ports as Bio-LNG. There will also be potential to serve off-grid communities with Bio-CNG, or Bio-LPG.

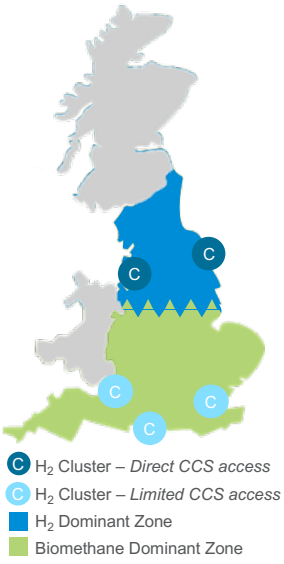


England

Hydrogen use will start at two clusters: near **Teesside / Immingham** in the northeast and around **Liverpool / Manchester** in the northwest. The availability of natural gas and access to potential CCUS facilities in the North Sea and Morecambe Bay will facilitate the production and use of hydrogen by industry in these two clusters.

Three other clusters could develop. A **Southampton Cluster** on the south coast may have potential access to CCUS offshore of the Isle of Wight. The **Thames Estuary Cluster** near to the Isle of Grain may have to follow an alternative development route as CCUS access will be more challenging. **Bristol** is expected to form part of a hydrogen cluster linking across south Wales

Biomethane (both anaerobic digestion and Bio-SNG) will be significant in England. Anaerobic digesters are likely to be numerous but relatively small scale, often remotely located. Network compression will be necessary to maximise the anaerobic digestion potential. Large Bio-SNG plants will be located at England's ports for feedstock supply but also to provide Bio-LNG for international shipping.

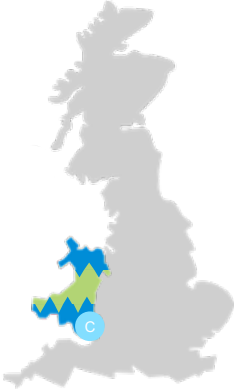


Wales

We anticipate that biomethane (from anaerobic digestion and Bio-SNG) will be the likely replacement for natural gas in Wales.

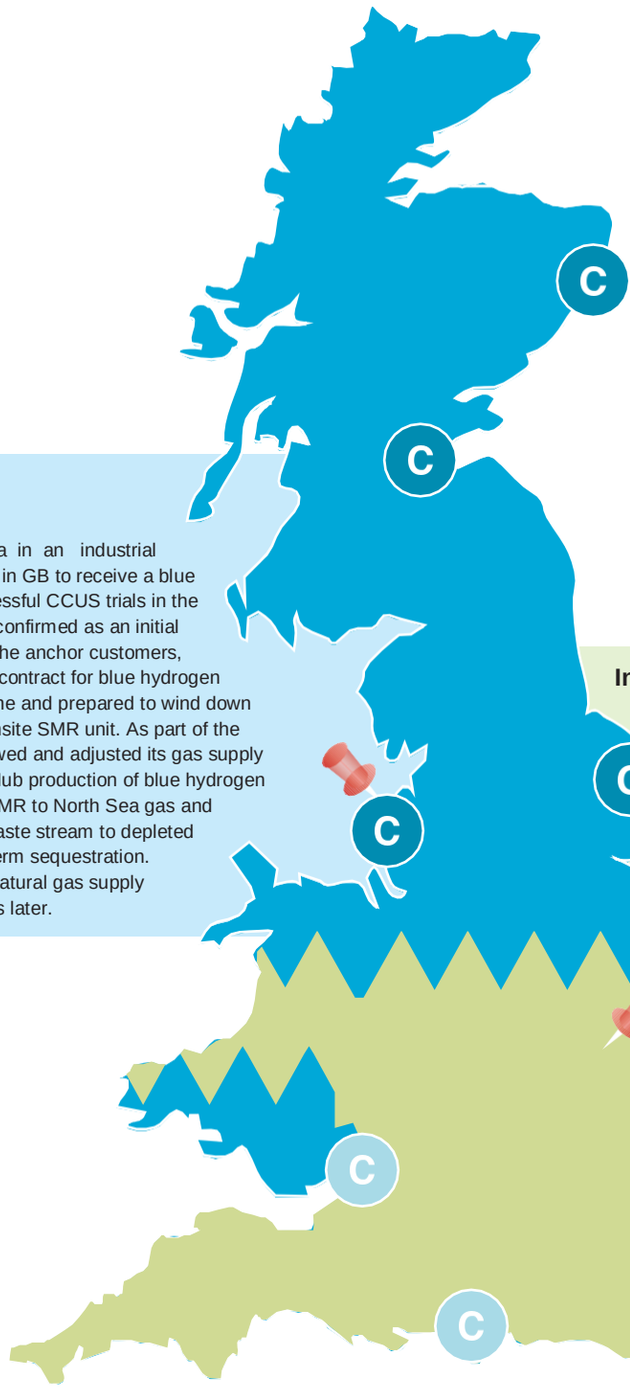
A Hydrogen Cluster may develop in **South Wales**, initially suppling industry and moving to the buildings sector. However, like the Thames Estuary Cluster, CCUS access in this location is challenging. There are several options to address this issue. Carbon dioxide could be exported by pipeline to a potential CCUS site offshore Ireland or shipped to a CCUS site in Morecambe Bay or via export to Norway. Alternatively, hydrogen could be produced by electrolysis, removing the need for CCUS.

Additionally, hydrogen may become available in North Wales through an extension to the Liverpool / Manchester Hydrogen Cluster near Morecambe Bay.



3.6.3 End-User Perspectives: Industry

These end-user perspectives help to illustrate how industry in different parts of GB may experience the Pathway to our 2050 Balanced Scenario.



Industry in an initial Hydrogen Cluster

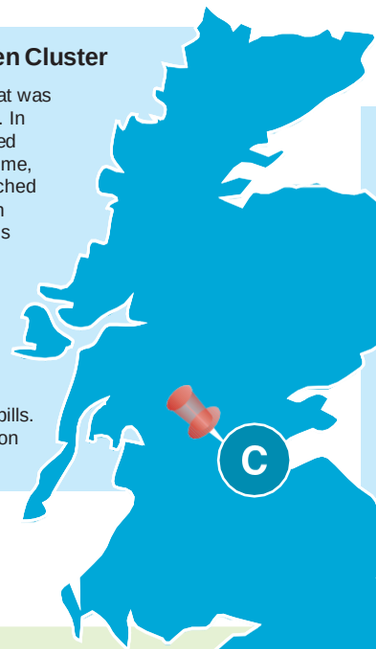
AlphaCo produces ammonia in an industrial area that was one of the first in GB to receive a blue hydrogen supply. After successful CCUS trials in the early 2020s, the region was confirmed as an initial hydrogen cluster. As one of the anchor customers, AlphaCo signed a long-term contract for blue hydrogen supply via a dedicated pipeline and prepared to wind down hydrogen production at its onsite SMR unit. As part of the preparations, AlphaCo reviewed and adjusted its gas supply and tankage infrastructure. Hub production of blue hydrogen began in 2026 by applying SMR to North Sea gas and then transporting the CO2 waste stream to depleted offshore gas fields for long-term sequestration. AlphaCo allowed its legacy natural gas supply contract to expire a few years later.

Industry in a Biomethane zone, outside Hydrogen Clusters

DeltaCo produces steel in an industrial area that eventually converted to 100% biomethane supply. To allow end-users to prepare and adapt, a long-term schedule was created for the ramp-up of biomethane blending into the area's gas supply, and thus the effect on calorific value and other specifications. As part of the preparations, DeltaCo invested in gas monitoring and control equipment to enable its processes to run seamlessly as the biomethane proportion increased over time.

3.6.3 End-User Perspectives: Industry

These end-user perspectives help to illustrate how people in different parts of GB may experience the Pathway to our 2050 Balanced Scenario.



Terraced house in an initial Hydrogen Cluster

Meet Oliver, whose terraced house is in a city that was one of the first in GB to convert fully to hydrogen. In 2026, the bus depot where he was working started getting a hydrogen supply. At around the same time, a regional public awareness campaign was launched about a programme to switch homes to hydrogen and getting hydrogen-ready appliances. When his gas boiler needed replacing a few months later, Oliver replaced it with a hydrogen-ready boiler, but it wasn't until 2031 that the gas supply on his street switched over to 100% hydrogen. In the mid-2030s, he upgraded to a hybrid heat system (with an air source heat pump) and chose to install more roof and window insulation in order to reduce his monthly energy bills. In 2050, Oliver is retired but makes regular trips on buses powered by hydrogen fuel cells.

Flat in a Hydrogen Zone but outside initial Hydrogen Clusters

Meet Emily, who lives in a town that converted fully to hydrogen in the late 2030s. She moved into a flat in 2025 that was already insulated to a moderate standard. At that time she heard about her cousin's home in a nearby industrial city switching over to hydrogen in 2031, but Emily's town was unaffected and stayed on a methane gas supply. In the early 2030s, a public awareness campaign was launched in her region about a programme to switch homes to hydrogen and getting hydrogen ready appliances. When her gas boiler needed replacing in 2035, Emily replaced it with a hydrogen-ready boiler, but it wasn't until 2038 that the gas supply on her street switched over to 100% hydrogen. A few years later, she upgraded to a hybrid heat system with an air source heat pump. Emily commutes to work in an electric car which she charges overnight from the power grid.

Semi-detached house in a Biomethane zone, outside Hydrogen clusters

Meet Poppy, who lives in a town in mid Wales. Her semi-detached home underwent a major renovation in 2025 and she took the opportunity to improve the insulation and upgrade to a hybrid heat system (with an air source heat pump) in order to reduce her monthly energy bills. Poppy has continued using a (methane) gas boiler; since 2035 it has been fuelled by 100% biomethane with a hydrogen blend, according to her gas supplier, but she hasn't noticed any difference in performance. She drives an electric car, charged primarily from PV panels on her roof, to commute to work and visit her parents. Poppy's parents live in a neighbouring town, in a new-build retirement complex which is supplied by a district heating system.

Detached house off the gas grid

Meet Mo, who lives in a rural area not connected to the gas grid. His detached house used to run on an oil-fired heating system, with fuel regularly delivered by truck. He improved the roof and window insulation in 2022 to reduce his monthly energy bills. In 2032, suppliers began offering truck deliveries of Bio-LPG in his area. Mo decided to overhaul his domestic heating in 2035, converting to a hybrid heat system featuring a gas boiler and a ground source heat pump in the garden; some of his neighbours use air source heat pumps instead. Mo drives an electric car which is charged using a solar PV and battery storage system.

Hard-to-insulate property in a Biomethane Zone, outside Hydrogen Clusters

Meet Jay, who lives in a town in southwest England. He moved into a poorly insulated, Grade II listed house in 2025. He has not been able to install a hybrid heat system nor significantly improve the energy efficiency of his house because of planning restrictions and prohibitive cost. Jay has continued using a (methane) gas boiler; since 2035 it has been fuelled by 100% biomethane, according to his gas supplier, but he hasn't noticed any difference in performance.

4. IMPACTS ALONG THE PATHWAY

We have examined the impacts as the Pathway proceeds towards our Balanced Scenario. We considered the following:

- **Gas quantities:** How do end-use gas quantities change over time? What is the ramp-up in production volumes of low carbon gases? How do volumes of different gases in the network change over time?
- **Energy system costs:** How does the transition to low carbon and renewable gases affect energy system costs?
- **Gas network operations:** How does the transition to low carbon gases affect the network and operations?
- **Carbon emissions:** How do carbon emissions from the gas sector fall over time? Do they meet the carbon budgets for net-zero?
- **End-user interventions:** What is the pace of end-user interventions such as insulation and hybrid heat system deployment?

4.1 Gas Quantities

4.1.1 Network Gas Quantities

Figure 11 below illustrates the quantities of different gases in the network over time as the energy system transitions to our 2050 Balanced Scenario:

- Gas quantities consumed by end-users;
- Natural gas used as feedstock for blue hydrogen production; and
- Hydrogen used indirectly as feedstock for power-to-gas biomethane and synthetic kerosene.

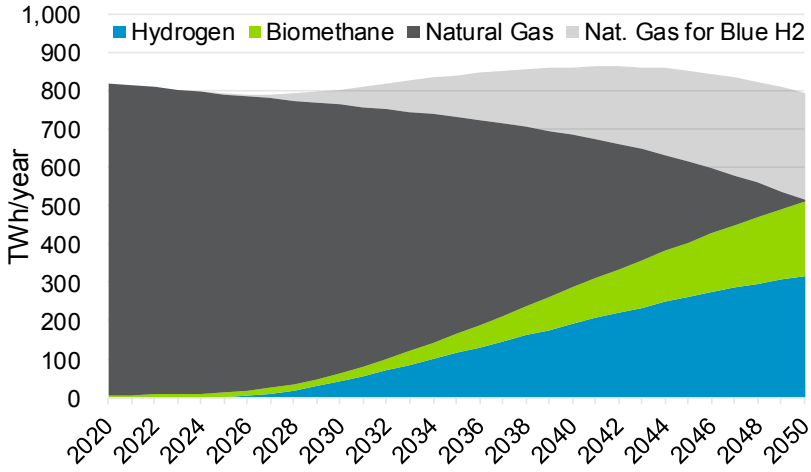


Figure 11 Network gas quantities along the Pathway[56]

[56] Network transport of carbon dioxide is not shown in this figure.

The figure shows that total gas quantity in the network may remain close to present levels between now and 2050. However, we expect most Blue Hydrogen production to be located close to coastal gas terminals where natural gas production is brought onshore (or onshore natural gas production sites), and thus there will be limited penetration of the natural gas into the onshore high-pressure network in 2050.

Hydrogen is also used as an intermediary feedstock for the production synthetic kerosene, which is used as a bio-sourced aviation fuel, and a small quantity of Green Hydrogen is consumed for power-to-gas biomethane. In our Pathway, Blue Hydrogen production facilities are located proximate to current refinery and chemical facilities (often as anchor end-users of the Hydrogen Clusters) and we anticipate that these facilities will transition to bio-fuels and / or bio-chemicals – such as the production of synthetic kerosene. Therefore, hydrogen quantities for use as an intermediate feedstock may only make limited use of the gas network.

Based on these assumptions, total gas quantities in the network could be lower and resemble end-user consumption quantities (see below). However, from a volumetric perspective, the gas networks must account for the lower energy density of hydrogen versus natural gas.

4.1.2 End-Consumption Quantities

Over the course of the Pathway, gas quantities consumed by end-users[57] fall by about half, from 820 TWh currently to 430 TWh in 2050. The low carbon and renewable proportion of gas consumed shifts from 0.5% today to 100% in 2050, of which 55% is hydrogen and 45% is biomethane.

The table and figure below show the transition over time. Note that gas used indirectly (e.g. natural gas feedstock for blue hydrogen production, and hydrogen feedstock for power-to-gas biomethane and synthetic kerosene) is considered in section 4.1.1, but not here.

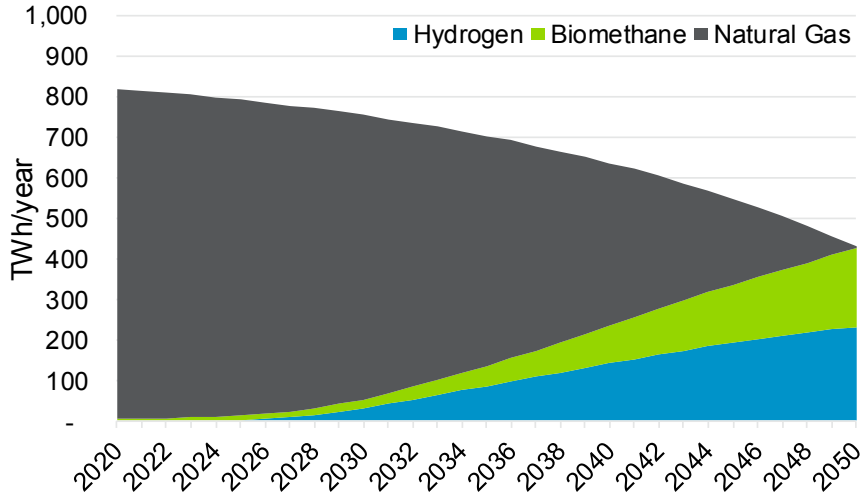


Figure 12 Gas end-consumption quantities along the Pathway

[57] Primary gas demand from power generation plus final gas demand from end-use sectors.

	Gas end-consumption	Low carbon and renewable gas end-consumption
By 2020	Gas quantities remain at current levels (~820 TWh)	Low carbon gas quantities account for ~0.5% (Anaerobic digestion only)
By 2030	Gas quantities decrease to 750 TWh (8% lower)	Low carbon gas quantities increase to 7% • Hydrogen ~4% (72% blue) • Anaerobic digestion Biomethane ~3%
By 2040	Gas quantities decrease to 635 TWh (22% lower)	Low carbon gas quantities increase to 38% • Hydrogen ~23% (67% blue) • Biomethane 15% (51% from Bio-SNG)
By 2050	Gas quantities decrease to 430 TWh (~50% lower)	Low carbon gas quantities reach 100% • Hydrogen ~55% (63% blue) • Biomethane ~45% (63% from Bio-SNG)

Table 1 Gas end-consumption quantities along the Pathway

4.1.3 Low Carbon and Renewable Gas Production

This transition requires a rapid scale-up in biomethane production from 3 TWh today (solely from anaerobic digestion) to 195 TWh in 2050 (from a combination of anaerobic digestion, Bio-SNG and power-to-methane).

- **Anaerobic digestion** production supplies 57 TWh in 2050. Biomethane increases from 3 TWh in 2018 to 22 TWh in 2030. We assume annual additions of 20 anaerobic digestion plants (averaging 1,000 m3 capacity per year) in 2020, increasing to 40 new anaerobic digestion plants/year from 2029 onwards. This is in line with current run-rates and stakeholder feedback. Total production capacity of 1.2 million m^3/hr would be achieved in 2050.

- **Bio-SNG** begins commercial deployment in 2030 and supplies 121 TWh in 2050. Deployment ramps up to 930 MW of new capacity per year, giving a total production capacity of 15 GW in 2050.

- **Power-to-gas biomethane** contributes a further 15 TWh of supply in 2050, using green hydrogen from curtailed electricity as input.

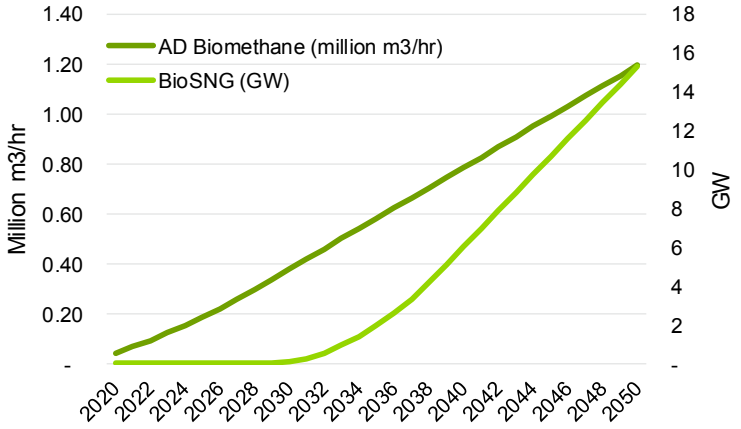


Figure 13 Biomethane production capacity along the Pathway

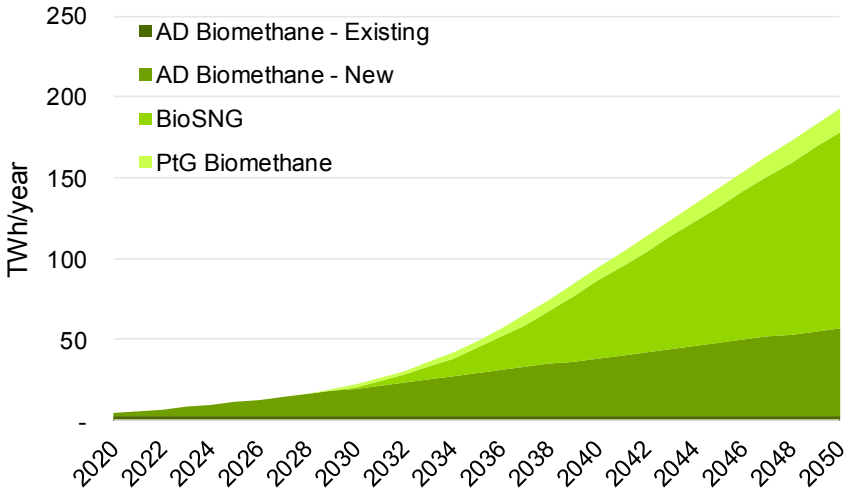


Figure 14 Biomethane production volumes along the Pathway

The transition also requires a significant scale-up in hydrogen production from negligible low carbon quantities today to 317 TWh in 2050.

- **Blue Hydrogen** production begins in 2025 and reaches 200 TWh in 2050. Deployment ramps up to 1.7 GW of new capacity per year throughout the 2030s, before decelerating in the 2040s when green hydrogen takes a greater share of new capacity. Total blue hydrogen production capacity is 35 GW in 2050, with a roughly equal split between ATR and SMR.

- **Green Hydrogen** production begins in 2026 and reaches 117 TWh in 2050, of which 55% is produced from dedicated renewables and 45% from curtailed renewables. Deployment of dedicated renewables ramps up to 1 GW of new hydrogen capacity per year from the 2030s onwards, giving a production capacity of 22 GW in 2050.

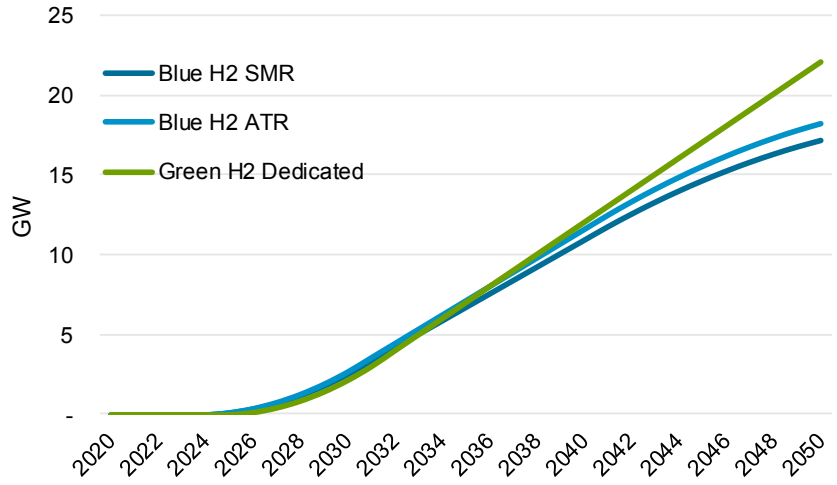


Figure 15 Hydrogen production capacity along the Pathway

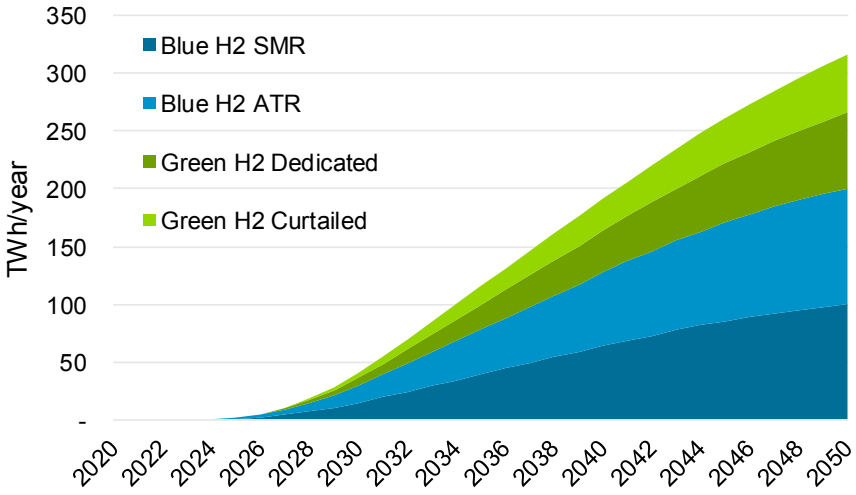


Figure 16 Hydrogen production volumes along the Pathway

It should be noted that the hydrogen production volumes described above include both:

- Hydrogen used directly in buildings, industry, transport and power; and
- Hydrogen used indirectly as feedstock for power-to-gas biomethane and synthetic kerosene.

4.2 Energy System Costs

As GB transitions to our Balanced Scenario in 2050, total energy system costs will increase. Figure 17 below shows indicative total system costs split into three categories:

- **Gas production and gas network:** These costs increase steadily to around GBP19bn/year in the mid-2040s, driven primarily by the costs of deploying and operating production facilities for low carbon and renewable gases. Network costs for transmission, distribution and integration of low carbon and renewable gases also increase with rising volumes, whereas network costs associated with natural gas fall to negligible levels.

- **Power production and power network:** These costs peak at around GBP24bn/year in the 2030s, comprising mainly the costs of deploying and operating low carbon generation plants. Transmission and distribution costs increase steadily as the power system expands. Network costs associated with connecting offshore wind are substantial until the mid-2040s.

- **End-user equipment:** These costs increase steadily to around GBP34bn/year in 2050, made up of installation costs for insulation and heating systems in buildings.

Across the whole system as modelled, total costs increase to roughly GBP63bn/year before levelling off in the mid-2040s. The sum of the energy system costs across the 30-year Pathway is approximately GBP1.5tn.[58]

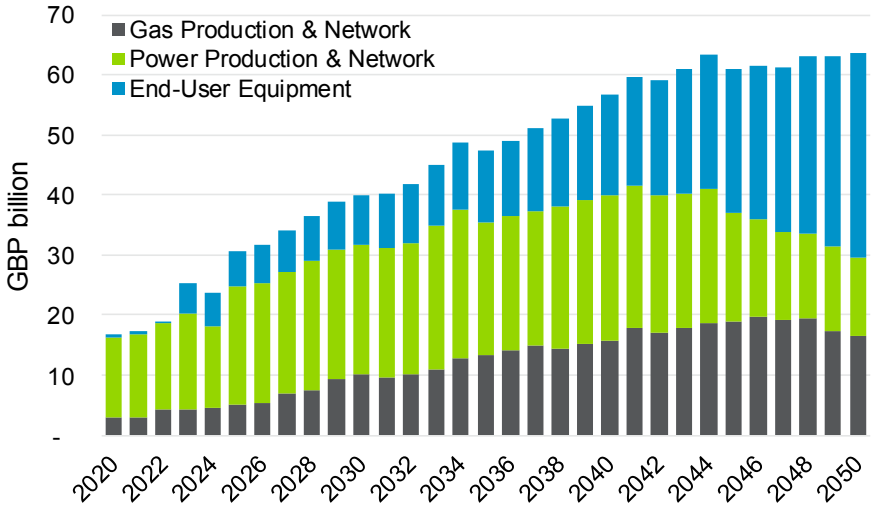


Figure 17 Indicative total system costs along the Pathway

[58] For our scenario modelling, we calculate an amortised capex over the 30-year Pathway period and add opex for 2050. For the Balanced Scenario, these costs total GBP109bn/yr.

4.3 Gas Network Operations

Network operations will become increasingly complex as the gas network moves from managing one to multiple gases in our Balanced Scenario.

Hydrogen will initially be blended in low quantities or used locally to production facilities, so network impacts will be minimal at the early stages of hydrogen supply development. However, anaerobic digestion biomethane additions in the early years will need network capacity improvements, such as in-grid compression of gas to higher tiers or interconnection of networks.

As low carbon and renewable gas volumes grow over time, biomethane and hydrogen will require network capacity, along with natural gas. Supply and demand of each gas will vary geographically across GB, so network complexity will increase considerably. Similarly, pipeline capacity for CO_2 transport may be required in the future system Detailed network planning will be needed at a pipeline-by-pipeline level to ensure continued supply security and access to seasonal storage. Network reinforcement and reconfiguration will likely be needed, either through repurposing of existing assets or building of new infrastructure. Achieving all this will require a high degree of coordination between the gas network companies.

If successfully developed at large scale, gas separation technologies would have the potential to significantly simplify network planning and operations to cope with multiple gases.

4.4 Carbon Emissions

The UK has currently set five-yearly carbon budgets which run through to 2032 and are based on reducing emissions by 80% from 1990 levels by 2050. In June 2019, a net-zero emissions target for 2050 was adopted into law.

In order to study the role that low carbon and renewable gases could play in a Pathway to a 2050 net-zero energy system, we have used the carbon budgets as currently defined to estimate the carbon budgets required to reach net-zero in 2050 and our Balanced Scenario. We have also focused on four of the largest emitting sectors in GB: Power Generation, Industry, Buildings and Transport. Both sets of carbon budgets are shown in **Figure 18** below.

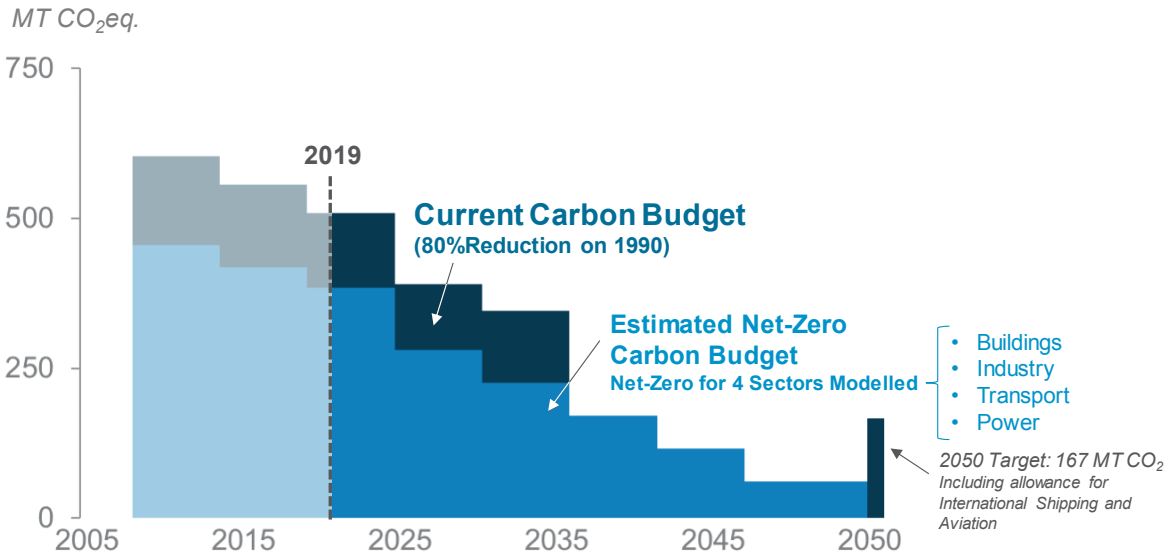


Figure 18 Carbon budgets to 80% reduction and net-zero in 2050

Figure 19 below shows gas-related emissions from the four sectors modelled in our analysis. Almost all gas-related emissions along the Pathway arise from consumption of natural gas. Emissions reductions in the early 2020s are small. Biomethane from anaerobic digestion starts from a very modest base and does not make a material impact until later in the Pathway. Early demand-side measures from energy efficiency such as insulation make a moderate difference. Electrification of demand is still reliant on natural gas in this period so the emission impact at this stage is also limited.

Supply-side decarbonisation starts via hydrogen production in the mid-2020s, but at this point is only for a limited number of anchor end-users. Hydrogen cluster development starts in the late 2020s and Bio-SNG production (starting in 2030), both provide significant emissions reductions from the 2030s onwards. Note that emissions reach net-zero in 2050, but there remain some emissions from Blue Hydrogen production that are balanced by negative emissions from Bio-SNG production coupled with CCS (see Table 2).

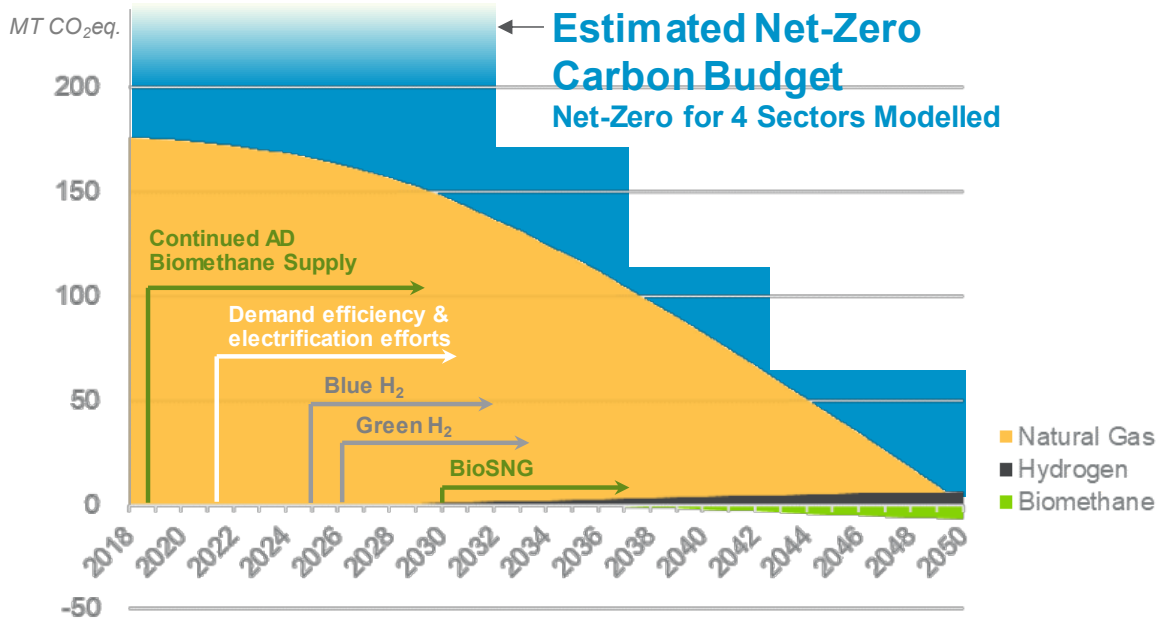


Figure 19 Gas-related carbon emissions vs. the estimated net-zero carbon budget

	Emissions related to Natural Gas	Emissions related to Hydrogen	Emissions related to Biomethane
In 2020	175 $MtCO_2e$	None	Negligible
In 2030	148 $MtCO_2e$	1 $MtCO_2e$	1 $MtCO_2e$
In 2040	82 $MtCO_2e$	4 $MtCO_2e$	-2 $MtCO_2e$
In 2050	None	7 $MtCO_2e$	-7 $MtCO_2e$

Table 2 Gas-related carbon emissions along the Pathway

In summary, gas-related emissions from our four modelled sectors can meet the estimated carbon budgets and our Balanced Scenario (which considers all emission sources for the four sectors) achieves net-zero emissions. However, the pace of decarbonisation may pose challenges in meeting the interim carbon budgets once non-gas emissions are taken into account. Non-gas emissions from industry, power, buildings and transport along the Pathway (e.g. from petroleum-based transport fuels) have not been modelled in the analysis above.

4.5 End-User Interventions

The Pathway to the Balanced Scenario requires significant work at the end-user level. End-user interventions in the buildings sector include:

- Installation or upgrade of insulation to improve building energy efficiency:
- Installation of a hybrid heat system (including a hydrogen-ready boiler, where appropriate); and
- Installation of other low carbon heating systems such as all electric heat pumps in new or off-grid buildings.

Our Pathway sees 22 million hybrid heat systems installed by 2050, from a negligible number today, predominantly targeting existing buildings already connected to gas networks. Hybrid heat system installations average 800,000 per year, ramping up to a maximum of 1.8 million per year in 2050. These buildings also undergo moderate insulation work to reduce energy demand.

In regions where hydrogen will be supplied, deployment of dual-fuel hybrid heat systems (i.e. systems including a hydrogen-ready boiler) needs to lead hydrogen gas supply by at least two years to ensure all heat systems in a conversion zone have been made hydrogen-ready well ahead of the planned switchover.

Existing buildings constitute around 75% of the 2050 building stock; the other 25% are new-builds. Roughly 20% of new-builds are insulated to a moderate level and supplied by district heating (assumed to be sourced from waste industrial heat). The remaining 80% of new-builds are extensively insulated as they are targeted for deployment of electric heat pumps (air source or ground source). 6 million of these heat pumps are installed by 2050.

Figure 20 and Figure 21 below show the scale-up of these end-user interventions along the Pathway.

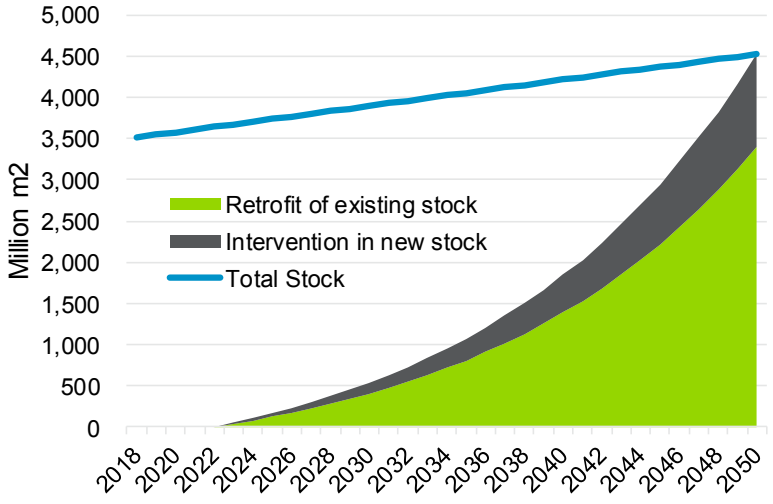


Figure 20 Interventions in existing and new buildings

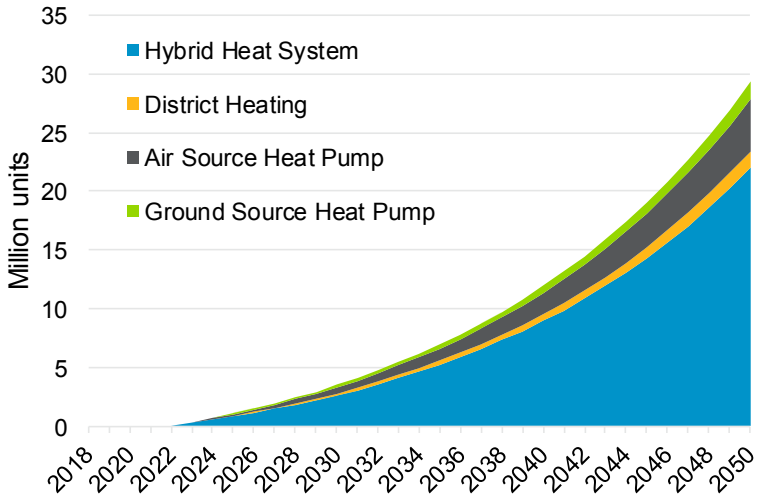


Figure 21 Cumulative installations of heating systems by type

To provide some historical context, loft insulation was rolled out nationally in about 22 years. The transition to condensing boilers is set to take roughly 25 years after becoming a mandated requirement. On the other hand, central heating took 50 years to implement in the absence of significant support to householders or a regulatory mandate; the driver was improved user experience and comfort levels. Therefore, the pace of end-user interventions required along our 30-year Pathway is daunting but achievable – as long as appropriate regulations and/or incentive measures are put in place.

Otherwise, the end-user interventions are likely to take much longer to achieve – the direct benefits from installing a heat pump or hybrid heat system are unlikely to be perceived by end-users as equivalent to installing central heating and that change took about 50 years.

We also acknowledge that it may not be practical to install a heat pump and/or moderate insulation in some properties. They would have to rely on a combination of a standalone gas boiler and light insulation. This challenge is explored below in Section 5.

In addition to the installation of insulation and heating equipment described above, we identified another end-user intervention in Section 5 related to the roll-out of hydrogen in the buildings sector. Once the hydrogen-ready appliances are in place and hydrogen supply for that region is secured, a brief engineer visit will be needed to carry out a safety inspection and prepare the appliances for a coordinated switchover to 100% hydrogen. This process will need to be planned and managed carefully to minimise end-user disruption and supply outages.

5. PATHWAY CHALLENGES

In the preceding chapters, we have described a Balanced Scenario representing a net-zero 2050 energy system, and a plausible Pathway to achieve it. Our work has been informed by the project's Expert Advisory Group and reviewed by Imperial College. We can therefore be confident that both the Balanced Scenario and the Pathway are credible views of the future.

However, as with any analysis of the future energy system, the Balanced Scenario and Pathway are subject to uncertainty. In this chapter, we present a sensitivity analysis to explore the key challenges and uncertainties, as outlined in Table 3.

The main findings from the sensitivity analysis are:

- The biggest risk to achieving net-zero emissions by 2050 is the **commercial viability of CCUS**. Net-zero cannot be reached if CCUS implementation is delayed, even if mitigating actions are taken such as greater deployment of extensive building renovation. The development of policies and support mechanisms to enable commercial deployment of CCUS are critical.

- **Industry adoption of hydrogen** is a key pathway risk. The start of Hydrogen Cluster development relies on having industrial baseload demand to build on. Without this, Cluster development will need to extend rapidly into the buildings sector, putting pressure on supply chains and network flexibility. The gas network companies should play a significant role in helping prepare industry to convert to hydrogen. Facilitating early hydrogen trials, providing direct technical support, and working with universities and other research institutions to help industry adapt their processes to hydrogen are examples of supporting activities.

- If the **price of hydrogen** is significantly greater, either due to the underlying technology cost or the cost of adapting CCUS to blue hydrogen production, then hydrogen volumes are expected to be lower. There is limited ability to increase biomethane to compensate. The low carbon and renewable gas supply chain should prioritise research and development to achieve the anticipated hydrogen cost reductions.

- Another notable pathway risk is the need for widespread **deployment of hybrid heat systems** and **buildings insulation**. While a net-zero energy system could be achieved with lower deployment of hybrid heat systems and insulation, overall costs are expected to be higher. This is open to challenge of course and in some regions if hydrogen or biomethane economics prove to be very cost effective and addition of heat pumps is challenging then all-gas heating remains a viable option. In our view however, the gas network companies should support hybrid heat system deployment and insulation improvements through programmes such as Freedom, requiring collaboration with electricity networks and other partners.

- From a **whole system perspective**, planning for a substantial role for low carbon and renewable gases is in itself a risk mitigation. Our Electrified Scenario is more costly than our Balanced Scenario. This cost difference could be halved if extensive building insulation can be installed alongside all-electric heat pumps (see Appendix E). But what if widespread renovation is not possible, even to a moderate standard, or all-electric heat pumps cannot be deployed in all buildings? Without low carbon and renewable gases as a significant part of the energy system, the only mitigating actions that could achieve net-zero by 2050 would be more power generation and greater electricity network reinforcement. With low carbon and renewable gases playing a greater role, there will be more options.

We carried out a quantitative analysis for each of the sensitivities in Table 3 (except the last one, which would require detailed modelling of network configurations). For each sensitivity, we took the main challenge and then tried to identify a reasonable set of mitigating actions that would enable the energy system to still reach net-zero in 2050; we compared the resulting system against the Balanced Scenario to show the differential in total system cost in 2050. For the CCUS delay sensitivity, we

found that net-zero became impossible to reach, so we also present a comparison of emissions in 2050.

Sensitivity	In the Balanced Scenario…	In the Sensitivity…
CCUS delay	A business model and policy framework are in place so that large-scale hydrogen production with CCUS can start in 2025	The Government policy decisions required to enable CCUS to proceed are delayed by 10 years
Less biomass imports	155 TWh of Biomass imports are available to produce Bio-SNG	Biomass imports are severely restricted
More expensive hydrogen	Hydrogen production costs will fall to a range of GBP50-60/MWh by 2050	The cost of hydrogen production is 50% higher at GBP75-90/MWh in 2050
Industry resistance to hydrogen	Industry leads conversion to hydrogen providing an anchor for cluster development	Half of industry is not able, or not willing, to convert to hydrogen
Less buildings renovation	75% of buildings are equipped with a hybrid heat system and moderate insulation	Hybrid heat systems and moderate insulation can only be installed in 25% of buildings. 50% of buildings use a gas boiler in combination with light insulation
Gas separation technologies deployed	Gas separation technologies cannot be deployed at grid scale	Gas separation technologies can be deployed in the networks to significantly simplify management of multiple gases

Table 3 Overview of Sensitivities

5.1 Commercial Viability of CCUS

Our Pathway envisages that CCUS will become commercially viable by 2025, in time for deployment in the first blue hydrogen production facilities. However, a stable regulatory framework and policy clarity are needed to establish a long-term, commercially sustainable business models for CCUS, and there is a significant risk that these may not be in place before 2025.

We have therefore tested the impact of a 10-year delay to CCUS commercial viability on our Balanced Scenario. We find that delayed CCUS deployment would make the 2050 net-zero emission target impossible to reach. In 2050, unabated hydrogen production (i.e. SMR/ATR without CCUS) would still account for 40% of hydrogen supply; a shortfall in CCUS adoption at biomass power plants would lead to fewer negative emissions.

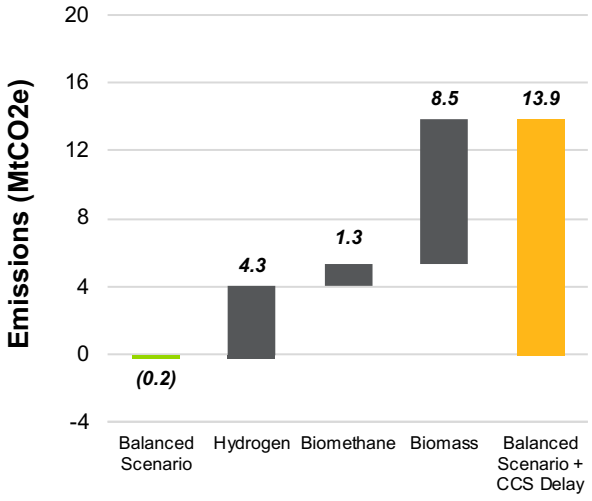


Figure 22 Impact of CCUS delay on 2050 emissions

Annual energy system emissions in 2050 would be roughly 14 $MtCO_2e$, despite aggressive mitigating actions to lower emissions to compensate (albeit partially) for the CCUS delay. These measures would also push up total energy system costs in 2050: more extensive insulation work across all buildings; more electric heat pump adoption and more renewables; and consequently higher transmission and distribution costs.

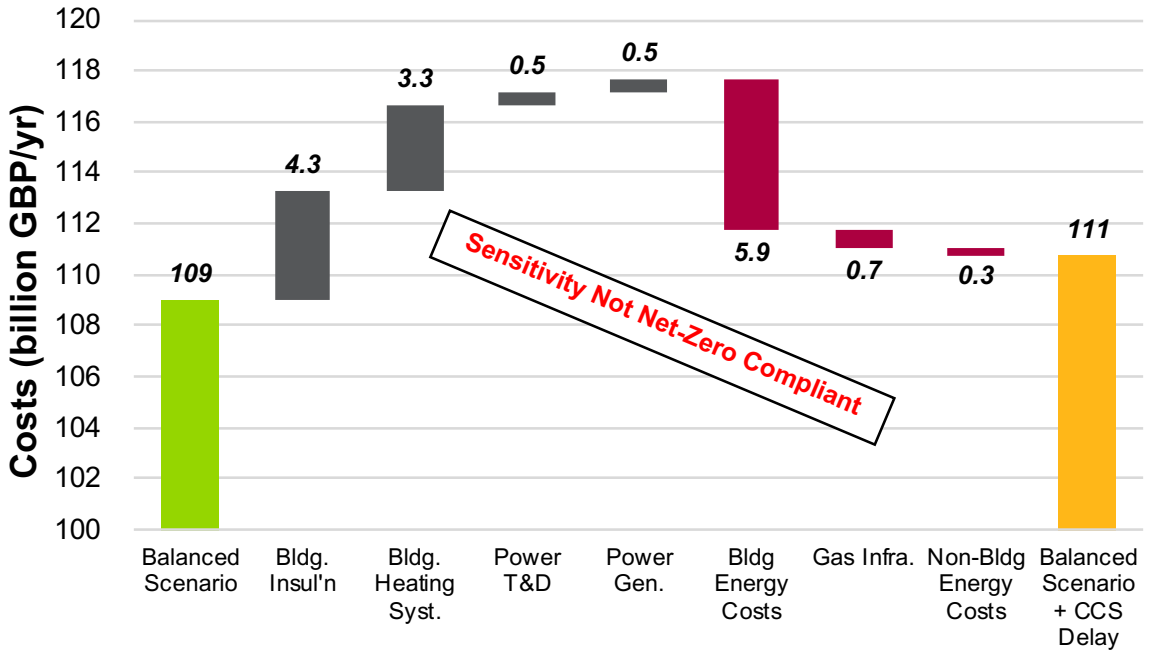


Figure 23 Impact of CCUS delay on 2050 energy system cost

The key conclusion is that timely and widespread deployment of CCUS is not optional; CCUS is a critical requirement for achieving net-zero emissions in 2050. In the near term, immediate action is needed to facilitate and establish the commercial viability of CCUS.

5.2 Biomass Import Availability

In our Balanced Scenario biomass availability utilises the CCC's Bioenergy in a low-carbon economy report and is based on CCC's 'Global Governance and Innovation' scenario. We therefore estimate 285 TWh of available solid biomass feedstocks, suitable for thermal gasification (to produce Bio-SNG or liquids fuels through the Fischer–Tropsch process), power generation or use in industry for heat. Imports make up 54% of the total (155 TWh), with the balance (130 TWh) UK feedstocks.

In this sensitivity we have tested the impact of a reduction in imported biomass (one third of supply is unavailable, relative to the Balanced Scenario) and therefore a decrease in biomethane availability. The remaining biomethane supply is used largely for international shipping (where no other feasible alternatives are available) with very limited biomethane use in buildings for heat. As a consequence, all-electric heat pumps are used more extensively in buildings. Where all-electric heat pumps are deployed, they are combined with extensive building renovation to improve energy efficiency. Dispatchable power generation is largely from hydrogen gas turbines given limited biomass supply, but some biomass capacity (with CCUS) is retained for negative emissions. Higher nuclear capacity of 45 GW also helps to meet increased demand for electricity overall.

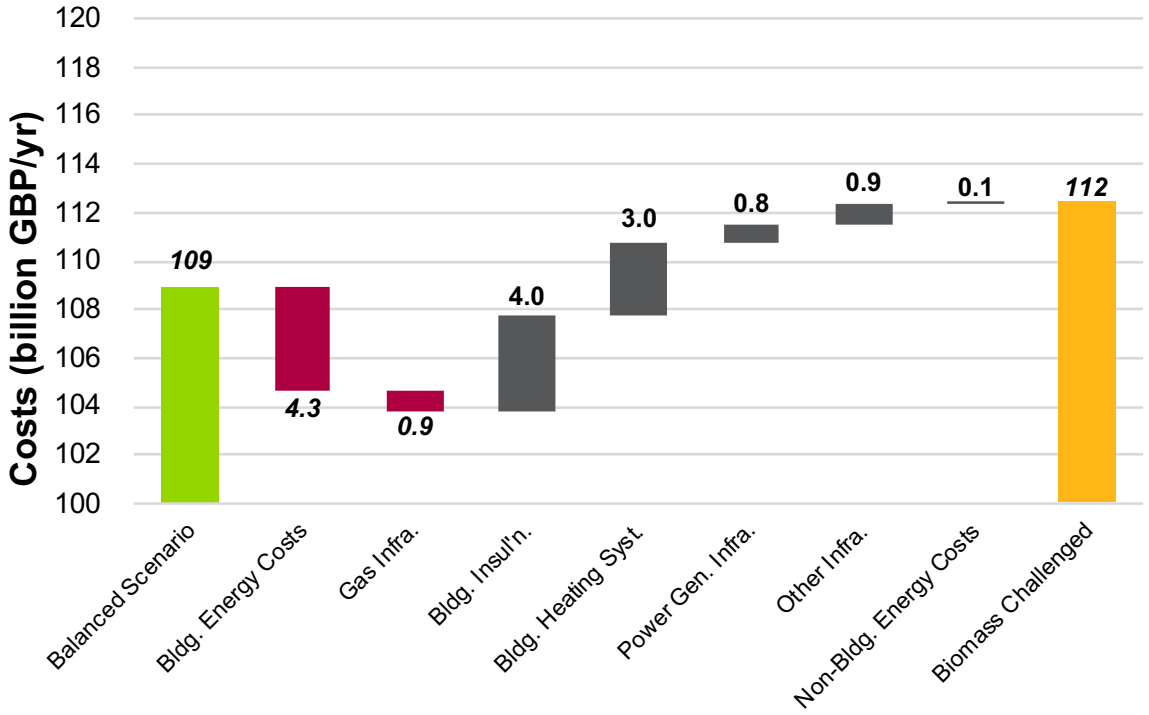


Figure 24 Impact of less biomass imports on 2050 energy system cost

This sensitivity shows a small cost increase over our Balanced Scenario of GBP3bn / year. From a gas networks perspective, it would likely make sense for the networks to move wholesale to hydrogen. The biomethane required for transport would be liquefied at the production facility and then trucked or shipped to transport hubs for storage and use. Subject to transport developments in the EU, road freight would likely move to Bio-LNG rather than Bio-CNG.

5.3 Hydrogen Production Costs

Our Pathway assumes that hydrogen production costs will fall to a range of GBP50-60/MWh by 2050 for both hydrogen from reforming of natural gas and electrolysis using dedicated renewables. However, this is dependent on technology improvements and cost reductions for reformers and electrolysers, which are not certain to materialise, as well as future natural gas feedstock costs.

We have therefore tested the impact of a 50% increase to hydrogen production costs on our Balanced Scenario. This reduces hydrogen demand by approximately 25% in 2050. We find that the net-zero target is still achievable, but total system costs rise due to the need for greater investment in building insulation, heating systems, power transmission and distribution, and power generation.

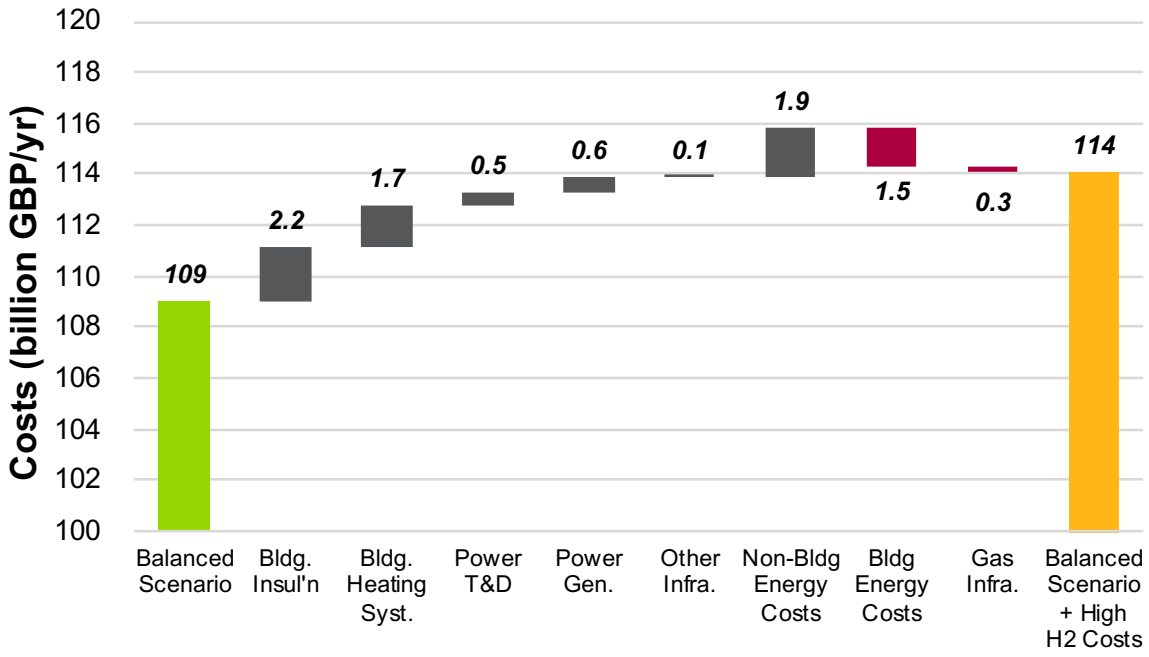


Figure 25 Impact of more costly hydrogen on 2050 energy system cost

Compared to the Balanced Scenario, the overall energy system would be much more reliant on electricity and bear closer resemblance to our Electrified Scenario. The greater extent of end-user interventions would be challenging to deliver.

This sensitivity shows a modest cost increase over our Balanced Scenario of GBP5bn / year. Overall gas volumes decrease due to lower hydrogen use, particularly in the buildings sector. The Hydrogen Clusters are therefore smaller. Biomethane volumes increase very slightly but not enough to offset the decrease in hydrogen.

5.4 Industrial Adoption of Hydrogen

Our Pathway envisages that baseload hydrogen demand from industry will anchor the development of Hydrogen Clusters. However, industry may resist fuel-switching to hydrogen; for low-temperature processes, there may be a greater preference to shift to electricity.

We have therefore tested the impact of 50% lower industrial adoption of hydrogen (i.e. 26 TWh of demand in 2050 moving from hydrogen to electricity) on the Balanced Scenario. The net-zero target would still be achievable, but the fuel-shift from gas to relatively expensive electricity would raise industry energy costs. There would also be modest increases in power transmission and distribution and gas infrastructure.

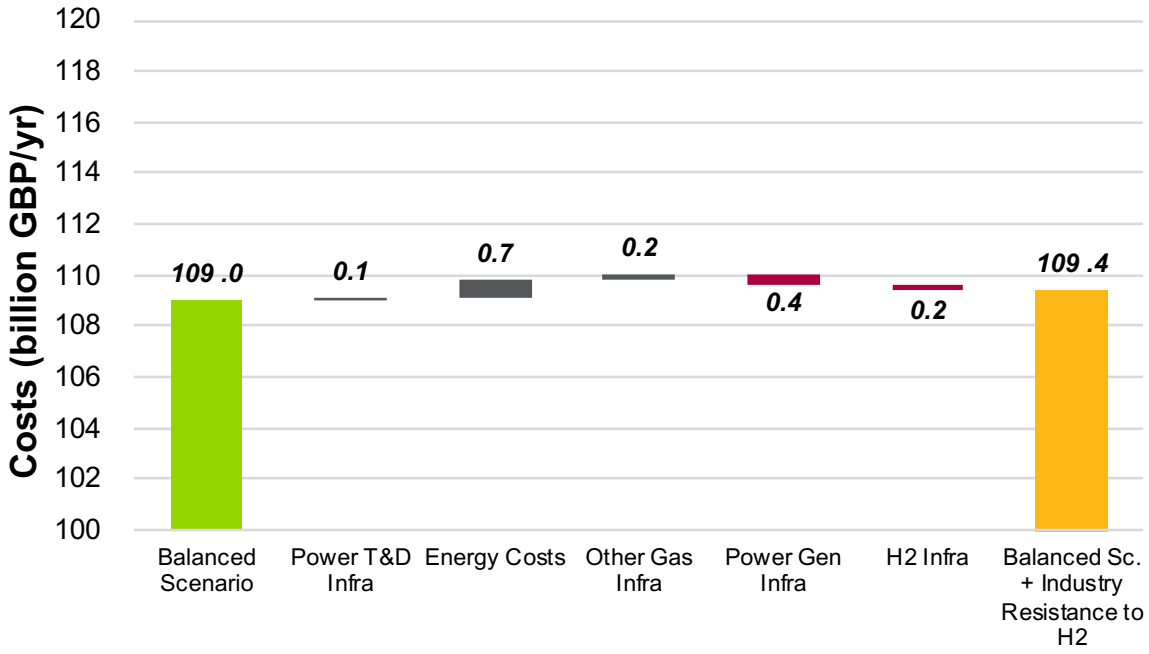


Figure 26 Impact of industry resistance to hydrogen on 2050 energy system cost

This sensitivity shows very little change in overall cost compared to our Balanced Scenario. However, the lack of industrial baseload demand for hydrogen would make it much more difficult to develop the Hydrogen Clusters. There is greater seasonality in buildings demand than industry, so network operations and supply security would be more difficult to manage; in particular, hydrogen storage facilities would be needed earlier in the timeline. “Hydrogen Ready” appliance conversion programmes would also need to be brought forward. Given these challenges of timing, a more likely outcome would be a slow start to the development of Hydrogen Clusters and then a need to accelerate rapidly to catch up. Either way, this would put a strain on resources, both skilled labour and supply chains. We conclude that industrial adoption of hydrogen, at scale and in a timely fashion, is an important requirement of our Pathway to the Balanced Scenario.

5.5 Building Renovation

Our Pathway to the Balanced Scenario requires a significant degree of end-user intervention in the buildings sector. In some properties, it may not be practical to install a heat pump and/or significant insulation. In other properties, householders may object to the intrusive renovation works needed to substantially improve energy efficiency.

We have therefore tested the impact of 50% of buildings continuing to use a gas boiler, rather than installing a heat pump as part of a hybrid heat system. We also assume that these buildings would undergo light renovation, instead of the moderate renovation assumed in our Balanced Scenario. The net-zero target would still be achievable, but gas demand in buildings would increase by approximately 25%, with peak gas demand increasing by 20% leading to higher building energy costs and gas infrastructure investment.

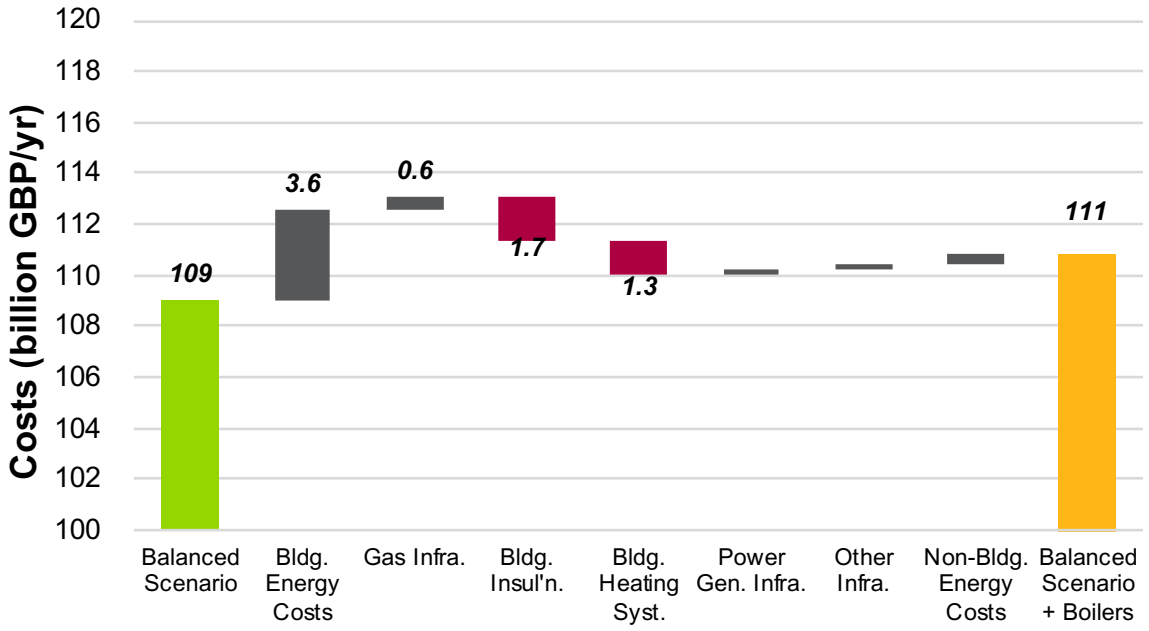


Figure 27 Impact of less buildings renovation on 2050 energy system cost

This sensitivity shows a small cost increase over our Balanced Scenario of GBP2bn / year. Hydrogen Clusters are likely to be larger (as average biomethane consumption per user will rise, reducing biomethane geographic coverage) and flow rates in the Hydrogen Clusters will increase.

5.6 Network Configuration

Hydrogen Clusters in our Pathway develop by:

- Initially supplying hydrogen via direct connection to anchor end-users;
- Blending hydrogen into the distribution system in the vicinity of potential Hydrogen Clusters to provide some limited flexibility; and
- Then converting end-users to 100% hydrogen through a carefully planned area-by-area rollout program, similar to that proposed by the H21 project.

As the Hydrogen Clusters expand geographically, they merge to form larger Hydrogen Zones. Within a Hydrogen Zone, the NTS will convert to 100% hydrogen (subject to local compatibility issues and other network constraints) to increase linepack for better operational management and to facilitate access to multiple hydrogen storage and production facilities for improved network supply security. Outside of the Hydrogen Zones, the NTS will continue to carry (bio)methane.

Assuming HyNTS proves NTS compatibility with hydrogen, the main obstacle to blending large quantities of hydrogen into the existing NTS is the acceptability of hydrogen blends to end-users directly connected to the NTS (CCGTs and some industry). However, having the option to blend large quantities of hydrogen into the existing NTS would provide significant benefits, such as:

- Long-distance transportation of hydrogen without the need for a duplicate hydrogen-specific, high-pressure network; and
- More flexibility to manage overall network development during the transition to hydrogen.

Gas separation technologies have the potential to unlock the benefits above, by allowing hydrogen and (bio)methane to be separated at key points in the network (e.g. exit points from the NTS to lower pressure tiers) and then delivered to different end-users. They could even enable the gas networks to transport *variable* blends of hydrogen and (bio)methane.

Several gas separation technologies are currently used at upstream gas processing, refineries and chemicals plants. However, application of these technologies at a high-pressure, transmission system scale, for the separation of hydrogen from methane, is not yet commercially proven. Costain, for instance, is presently investigating the viability of these technologies.

If gas separation technologies prove to be commercially viable, they would have significant implications for the deployment and management of low carbon and renewable gases across GB.

Delivery of Hydrogen to Other Clusters: Our Pathway is based on the development of Hydrogen Clusters in coastal locations where there is access to potential hydrogen demand, natural gas supply and importantly CCUS potential. The capability to blend hydrogen to high concentrations in the NTS, and the application of gas separation technologies, would enable the transmission of hydrogen produced at these coastal locations to other inland or southern areas of GB. This could enable a Hydrogen Cluster to be developed at locations such as Sheffield or Birmingham. This technology could provide an alternative mechanism to deliver hydrogen to the proposed South Wales / Bristol Hydrogen Cluster where access to CCUS is not easily available.

Isolation of End-Users from Hydrogen: There will be end-users who may not be able to receive a high concentration of hydrogen in their gas supply (current combined cycle gas turbines for example). The use of gas separation technologies could isolate those end-users from a hydrogen blend until they are able to secure a separate biomethane supply or are able to accept a 100% hydrogen gas connection.

Flexibility in Gas Infrastructure Deployment: During the GB energy system transition to a net-zero emission status, the role of the gas networks will become increasingly complex with a combination of natural gas, biomethane, and hydrogen requiring transmission. The use of gas separation technologies has the potential to reduce the need to provide network reinforcement (i.e. new network infrastructure) to move multiple gases separately through the network systems.

Managing Hydrogen Supply / Demand Imbalances: The initial hydrogen supply will be directly linked with anchor end-users who will require a relatively stable supply profile. However, as more end-users are added and the Hydrogen Cluster starts to develop, there may be imbalances between supply and demand that cannot be easily managed by the small storage facilities that will be constructed at the early stages of the Hydrogen Cluster development. The capability to blend large quantities of excess hydrogen production into the NTS for supply to end-users further along the network would provide additional network management flexibility.

APPENDIX A. EXPERT ADVISORY GROUP ENGAGEMENT

1. Workshops

A.1.1 EAG Workshop 1. (London – 23 March 2019)

Discussed the project's objectives, the role that gas can play in a 2050 energy system and the carbon emission target(s) that should be used in our analysis

Anaerobic Digestion and Bioresources Association, Thom Koller (Senior Policy Manager)

Chemical Industries Association, Richard Woolley (Head of Energy and Climate Change)

CCS Association, Chris Gent (Policy Manager)

Citizens Advice, James Kerr (Senior Policy Researcher)

Energy Networks Association, Matt Hindle (Head of Gas)

Energy Systems Catapult, Richard Halsey (Innovation Business Leader)

Energy Utilities Alliance, Josh Newbury (Senior Parliamentary Officer)

Greenpeace, Doug Parr (Chief Scientist and Policy Director)

GTC, Alex Green (Head of Innovation)

ITM Power, (Marcus Newborough (Development Director)

Johnson Matthey, Sam French (Syngas New Market Manager)

MakeUK, Frank Aaskov (Senior Energy and Environment Policy Advisor)

Oil & Gas UK, Tom Evans (Independent Consultant)

PEEL, Tony Smith (Commercial Strategy Manager)

Progressive Energy, Chris Manson-Whitton (Director)

Renewable Energy Association, Sam Stevenson (Bioenergy policy analyst)

UKPN, Adriana Laguna (Senior Innovation Strategy Manager)

A.1.2 EAG Workshop 2. (London – 01 May 2019)

Presented the concept of the Pathway and sought views on key aspects, including biomethane, hydrogen, buildings, industry and CCUS

Anaerobic Digestion and Bioresources Association, Alberto Rocamora (Policy Officer)

CCS Association, Chris Gent (Policy Manager)

Chemical Industries Association, Richard Woolley (Head of Energy and Climate Change)

Citizens Advice, James Kerr (Senior Policy Researcher)

Decarbonised Gas Alliance, Corin Taylor (Head)

Energy Systems Catapult, Paul Guest (Senior Modelling Analyst)

Energy UK, Charles Wood (Policy Manager)

Energy Utilities Alliance, Isaac Occhipinti (Head of External Affairs)

ESP Utilities Group, Vince Smith

GMB, Charlotte Nichols (Research and Policy Officer)

GTC, Alex Green (Head of Innovation)

IGEM, Ian McCluskey (Head of Technical Services)

ITM Power, Marcus Newborough (Development Director)

Johnson Matthey, Sam French (Syngas New Market Manager)

Ofgem, David Hawkey (Senior Network Analyst)

PassivSystems, Ian Rose (Professional Services Director)

PEEL, Tony Smith (Commercial Strategy Manager)

Progressive Energy, Mike Cairns-Terry (Project Engineer)

Renewable Energy Association, Kiaro Zennaro (Head of Biogas)

SP Energy Networks, Alan Collinson (Engineering Specialist)

Storengy UK Ltd, Duncan Yellen (New Production Development)

UKPN, Adriana Laguna (Senior Innovation Strategy Manager)

Welsh Government, Ron Loveland (Advisor to Welsh Government)

Worcester Bosch, Neil Schofield (Head of Sustainable Development)

University of Birmingham, Robert Steinberger-Wilckens (Prof Dr Chair in Fuel Cells and Hydrogen)

A.1.3 EAG Workshop 3. (London – 20 June 2019)

Reviewed the near-term actions that the gas industry needs to take to decarbonise the energy system by 2050

Anaerobic Digestion and Bioresources Association, Rebecca Thompson (Policy Manager)

CCS Association, Chris Gent (Policy Manager)

Chemical Industries Association, Richard Woolley (Head of Energy and Climate Change)

Citizens Advice, Zoe Guijarro (Senior Policy Researcher)

Costain, Chris Barron (Principle Consultant)

Decarbonised Gas Alliance, Corin Taylor (Head)

Energy Systems Catapult, Paul Guest (Senior Modelling Analyst)

Energy UK, Julie Cox (Head of Gas Trading)

Energy Utilities Alliance, Isaac Occhipinti (Head of External Affairs)

ESP Utilities Group, Vince Smith

GMB, Charlotte Nichols (Research and Policy Officer)

GTC, Alex Green (Head of Innovation)

Industrial & Commercial Energy Association, Ross Anderson (Director)

IGEM, Ian McCluskey (Head of Technical Services)

Institute of Mechanical Engineers, Jen Baxter (Head of Engineering)

ITM Power, Marcus Newborough (Development Director)

John Laing Capital Management, William Mezzullo (REA Biogas Steering Group Member)

Johnson Matthey, Sam French (Syngas New Market Manager)

London Office of the Agent General, Government of South Australia, Joe Doleschal-Ridnell (Investment Director)

National Farmers Union (NFU), Jonathon Scurlock (Chief Renewable Energy Adviser)

PassivSystems, Ian Rose (Professional Services Director)

PEEL, Tony Smith (Commercial Strategy Manager)

Policy Connect, Joanna Furtado (Senior Researcher)

Renewable Energy Association, Kiaro Zennaro (Head of Biogas)

Storengy UK Ltd, Duncan Yellen (New Production Development)

UK Hydrogen and Fuel Cell Association, Celia Greaves (Executive Officer)

UKPN, Adriana Laguna (Senior Innovation Strategy Manager)

University College London (H2 Research), Daniel Scamman (Senior Research Associate)

University of Edinburgh, Julien Mouli-Castilo (Postdoctoral Research Assistant)

Welsh Government, Ron Loveland (Advisor to Welsh Government)

2. Other stakeholder engagement

In addition, we met with several additional stakeholders during the course of this project:

BEIS, Amy Salisbury (Heat of Hydrogen Heating Team)

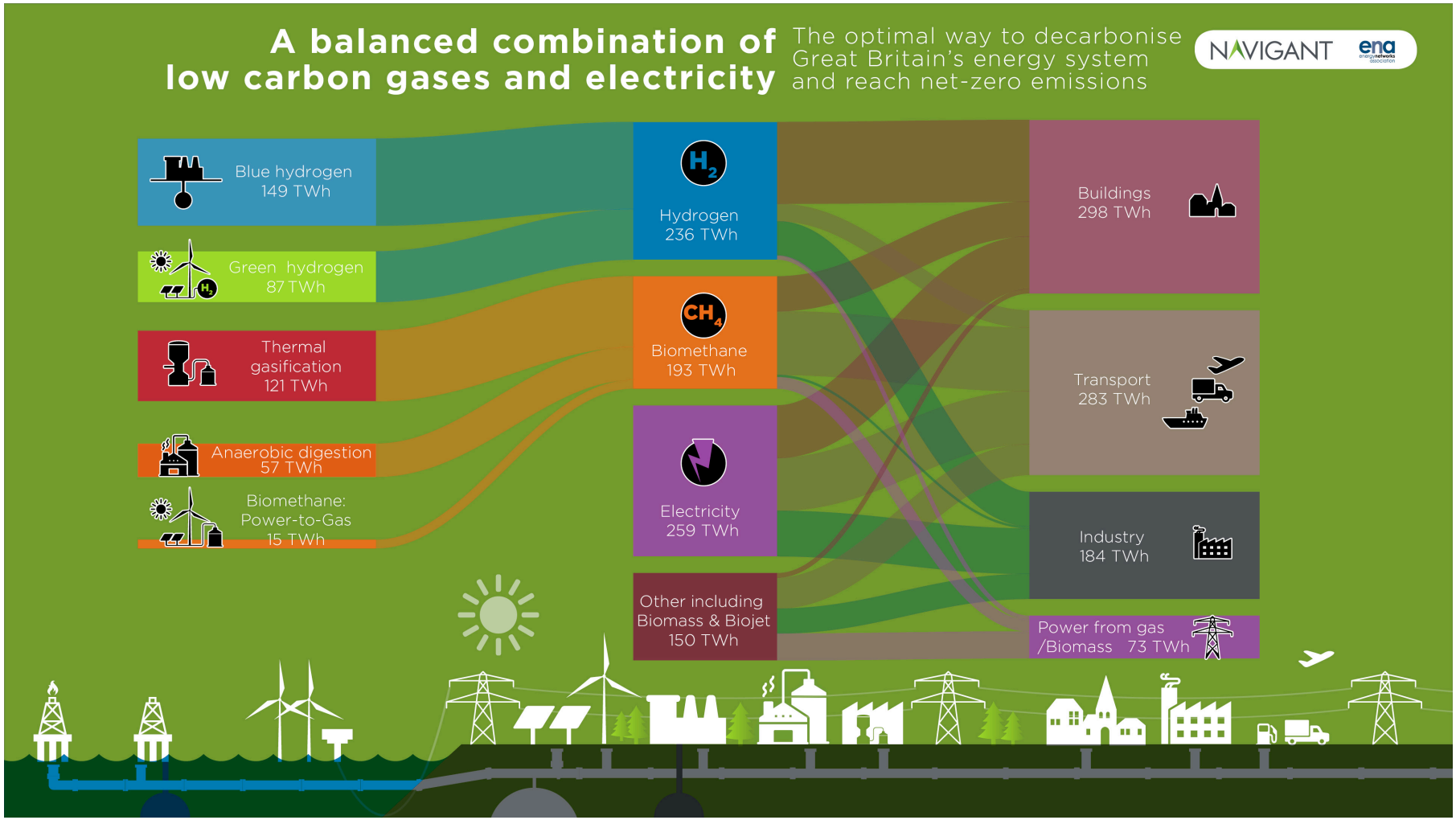
BEIS, Richard Leyland (Deputy Director, Heat Programme)

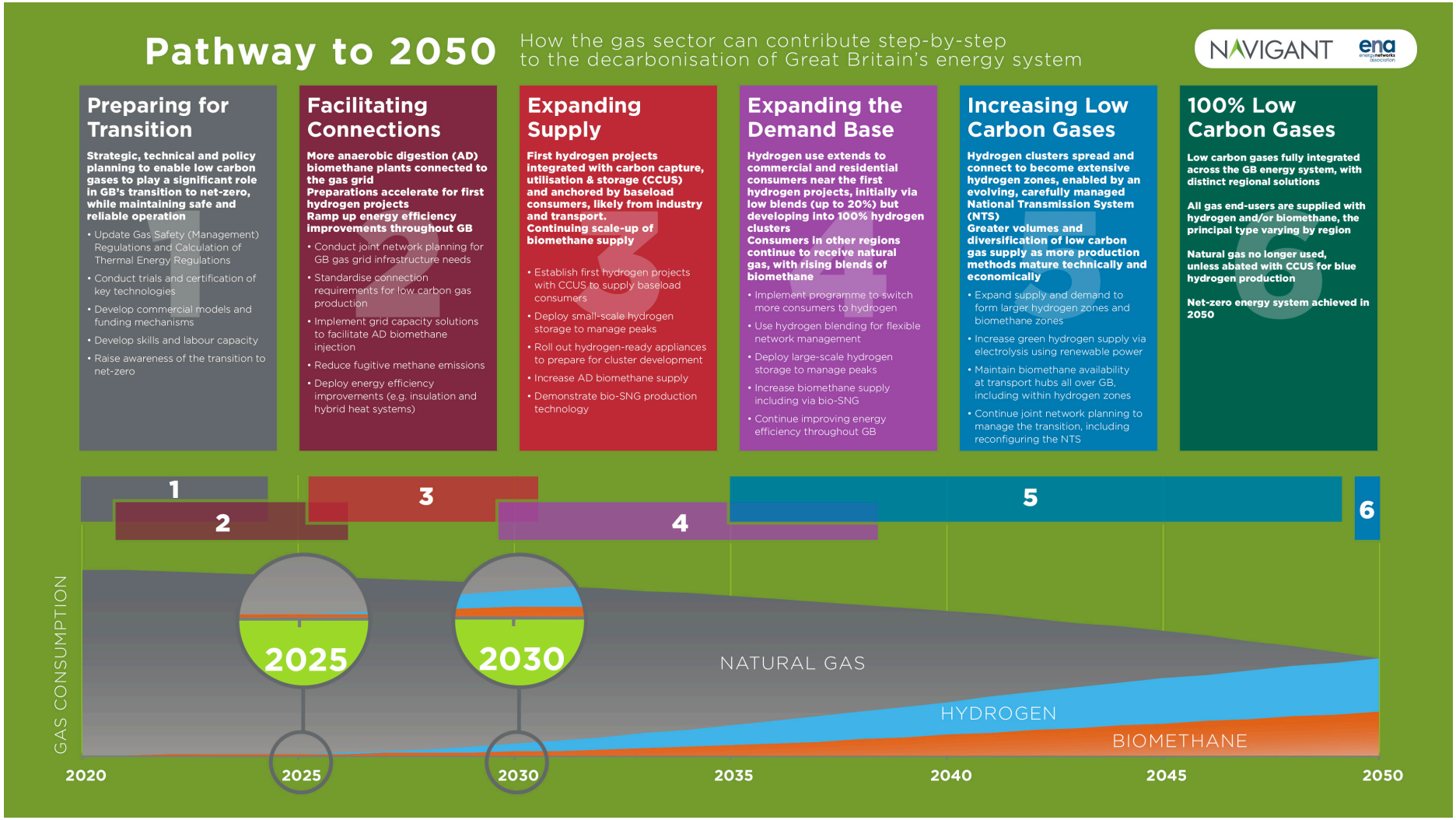
CNG Services, John Baldwin (Managing Director)

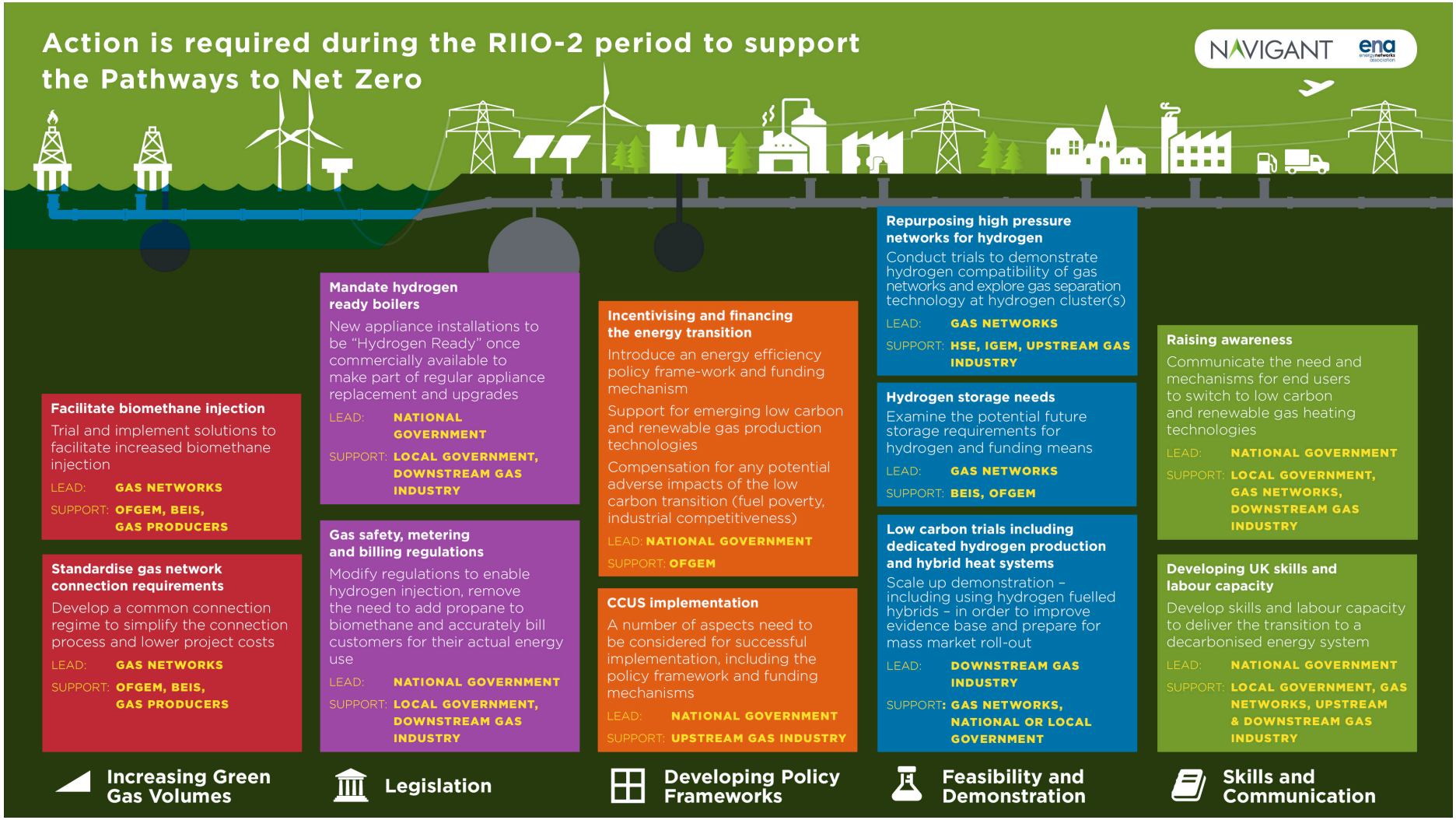
Committee on Climate Change, David Joffe (Team Leader, Economy-Wide Analysis)

Ofgem, Pete Wightman (Head of RIIO Gas Networks), Eleanor Warburton (Deputy Director, Gas, Heat and Emerging Issues); David Hawkey (Senior Network Analyst)

APPENDIX B. INFO-GRAPHICS







APPENDIX C. LOW CARBON AND RENEWABLE GASES

Biomethane and hydrogen play pivotal roles in the decarbonisation of GB, as they will largely displace natural gas use across all sectors. This section explores in more detail production technologies for both biomethane and hydrogen.

In our net-zero scenarios, renewable and low carbon gases have a role to play in the decarbonisation of the GB energy system to 2050. Biomethane and hydrogen are expected to, over time, displace natural gas use in buildings, industry, transport and power. Hydrogen will be supplied via two production technologies, while biomethane will be supplied via two main technologies and a third more costly and likely more limited source (e.g. power-to-gas). An overview of these technologies is provided below.

Hydrogen		Biomethane		
Natural Gas Reforming	**Electrolysis**	**Anaerobic Digestion**	**Thermal Gasification**	**Power-to-Gas**
Production technology based on the thermochemical conversion of natural gas to hydrogen combined with carbon capture and storage (CCS) – so called "Blue Hydrogen"	Production process using electricity to split water into hydrogen and oxygen – so called "Green Hydrogen"	Commercially available and widely used biological process for converting biomass into biogas in the absence of oxygen	Solid feedstock is heated in the presence of a reduced concentration atmosphere comprising air, oxygen or steam, to produce a syngas, which undergoes additional processing to produce biomethane ("Bio-SNG")	Synthetic methane can be produced based on hydrogenation of carbon dioxide, using captured CO2 from AD plants and H2 from excess electricity

Figure 28 Hydrogen and Biomethane Production Technologies

1. Biomethane

Anaerobic digestion is a commercially available and widely used biological process for converting biomass into biogas in the absence of oxygen. Typical feedstocks for anaerobic digestion are wet organic waste materials such as manures, sewage sludge, food wastes as well as crops such as maize. The process results in biogas and digestate, a solid fraction, consisting of what is left from the treated feedstock (typically around 85% of the input material).

Biogas contains around 55% methane, the rest being mainly short carbon cycle carbon dioxide, water vapour and trace amounts of other gases, such as oxygen, nitrogen and hydrogen sulphide. The digestate is a nutrient rich substance that can be spread to fields as fertiliser.

To enable injection into the gas grid, biogas needs to be upgraded to biomethane with 97% methane content, a process in which the carbon dioxide, water and other trace gas impurities are removed. Biomethane must be enriched with (bio)propane prior to injection to homogenise the calorific value in order to meet the calculation of thermal energy regulations (CoTER). The level of spiking according to the UK Renewable Energy Association is typically 5-12% by energy[59].

[59] REA (2010) CV Enhancement (1). https://www.ofgem.gov.uk/ofgem-publications/47872/rea-ofgem-6-aug-10pdf

The figure below provides a schematic overview of the anaerobic digestion production process.

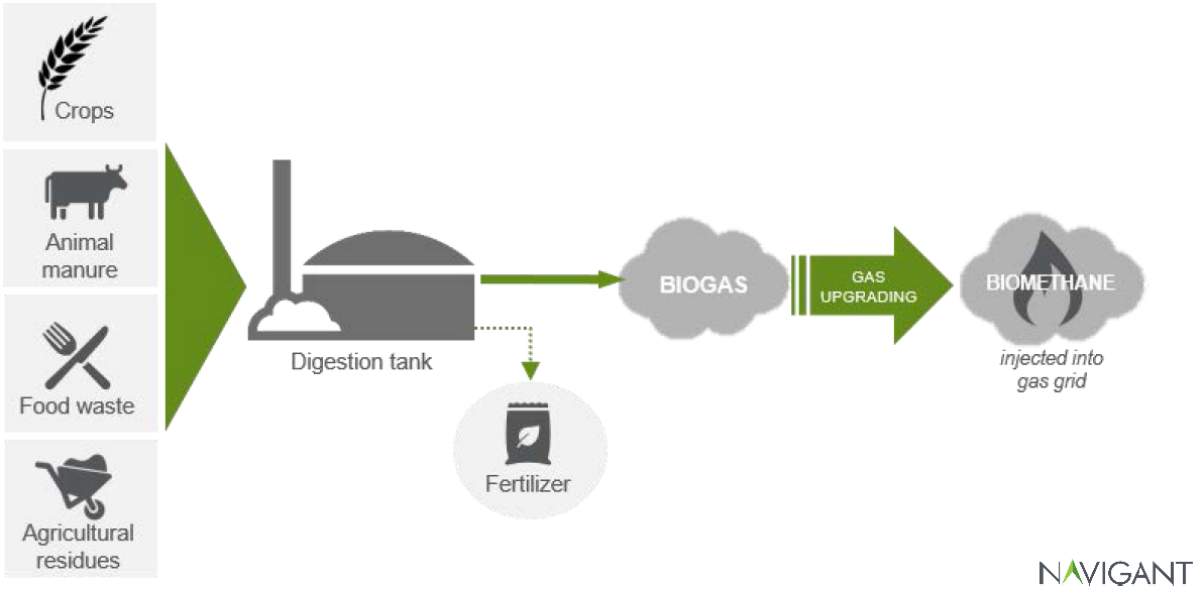


Figure 29 Schematic overview of the anaerobic digestion process

Thermal gasification is a process whereby a solid feedstock is heated in the presence of a reduced concentration atmosphere comprising air, oxygen or steam, to produce a synthetic gas (syngas) which is a mixture of carbon monoxide, hydrogen, and carbon dioxide. The syngas is cooled, and ash content is removed. In a gas cleaning unit, pollutants like sulphur and chlorides are separated. Methanation of the syngas is then performed in a catalytic reactor using nickel catalysts. With methanation, the cleaned gas is converted into Biomethane (Bio-SNG), carbon dioxide and water. Carbon dioxide and water are then removed in a gas upgrading unit.

In the usual Bio-SNG production process, a relatively pure carbon dioxide stream is produced, which could potentially be captured, compressed and stored with minimal additional processing, achieving "negative emissions". As the carbon dioxide must already be separated, minimal additional technology is required for integration of Bio-SNG with carbon capture.

The figure below presents the schematic overview of the thermal gasification process.

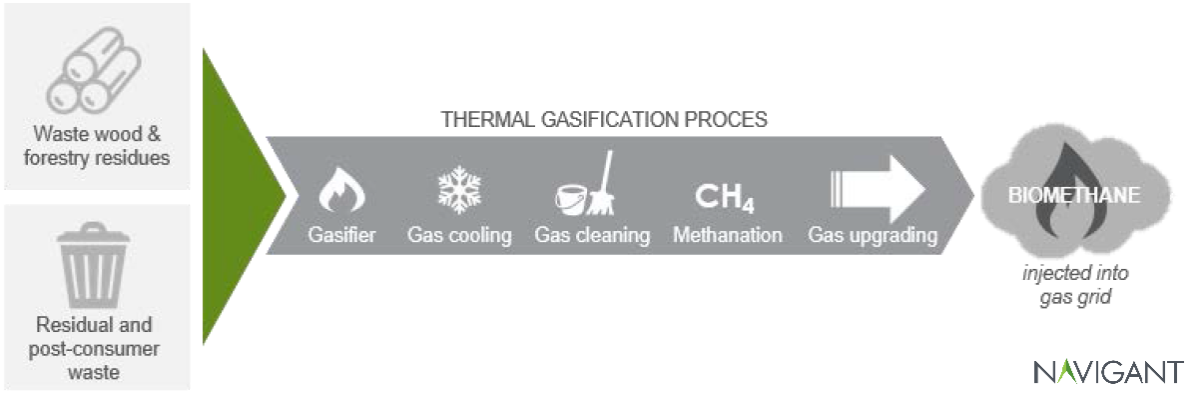


Figure 30 Schematic overview of the thermal gasification process

2. Hydrogen

Blue hydrogen is a low carbon gas produced by the thermochemical conversion of fossil fuels (typically natural gas) in combination with CCS. Two production technologies are considered, the currently dominant steam methane reforming (SMR), and autothermal reforming (ATR). In the ATR set-up, a larger share of carbon dioxide can typically be captured and no additional burning of gas for heat is required since the process is exothermic. However, the ATR process does require an oxygen supply, which leads to additional electricity-related emissions if the oxygen is not supplied as a by-product or as renewable power, thus partly offsetting the climate-related advantage of ATR.

The figure below presents the schematic overview of the hydrogen production process via reforming of natural gas.

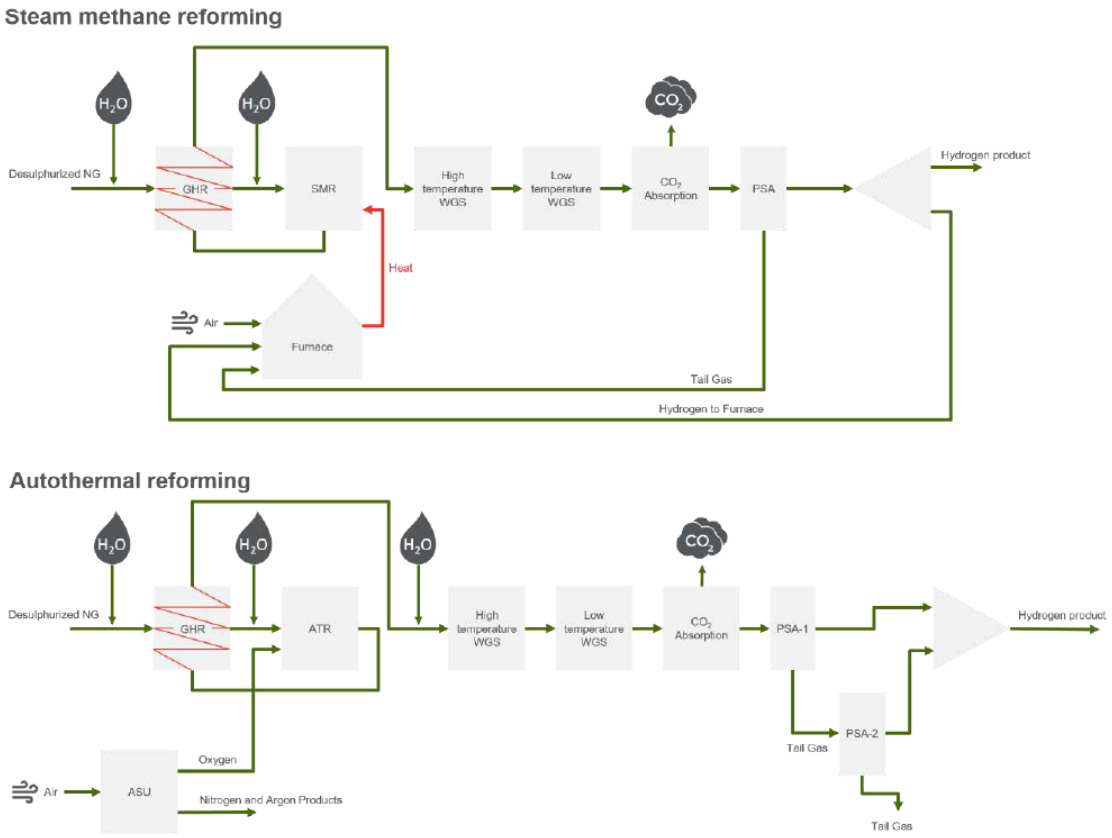


Figure 31 Comparison of steam methane reforming (SMR) and autothermal reforming (ATR) hydrogen production technologies

Green hydrogen can be produced through the following three technologies:

- **Alkaline Electrolysers (AE)** are the most mature and currently cheapest (GBP/kW) technology option. However, they have limited ability to respond to load changes, which is essential for the flexibility requirements of a power system with high penetration of renewables. Furthermore, the design is complex, implying limited cost-reduction options.
- **Proton Exchange Membrane (PEM)** electrolysers have a simple design, are currently more expensive than alkaline electrolysers, and are assumed to have a high cost-reduction potential. Crucially, they are flexible, with ramp up or ramp down times in seconds, which makes them ideal for a variety of applications in the power sector.
- **Solid Oxide Electrolysis Cells (SOECs)** use high temperature electrolysis; they are at an early stage of development. Theoretically, solid oxide electrolysis is a promising technology

due to its high efficiency, its ability to recover the heat needed for electrolysis, and its possibility to operate in reverse mode (regenerative electrolysis). The inability to have a flexible load and the high degradation of the membranes are the two major challenges of SOECs.

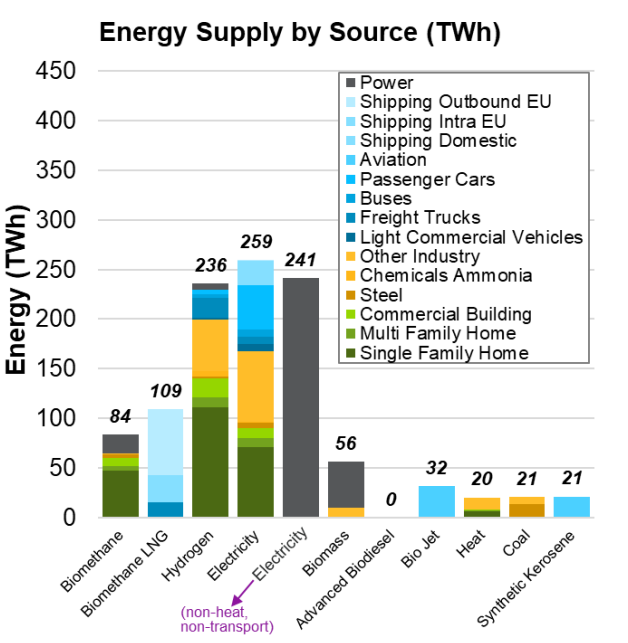
APPENDIX D. DETAILED RESULTS OF BALANCED SCENARIO

This section explores in detail the results of the Balanced Scenario. In the Balanced Scenario, heat supply in buildings is primarily from gas sources, with hydrogen and biomethane replacing natural gas. Hybrid heat systems become the dominant option for heating buildings, with limited adoption of all-electric heat pumps. In industry, hydrogen becomes the prominent option to displace natural gas in high and medium-temperature industrial processes, however, electrification of low-temperature processes also occurs. In transport, light and medium road transportation is mostly electrified, with hydrogen and biomethane being used in heavy transport applications like freight. International shipping relies predominantly on Bio-LNG while domestic, short-distance shipping becomes electrified. Finally, aviation relies heavily on bio- and synthetic fuels, and in the power sector, hydrogen and biomethane-fired gas turbines (GTs) and decentralised flexible gas engines replace all natural gas dispatchable generation.

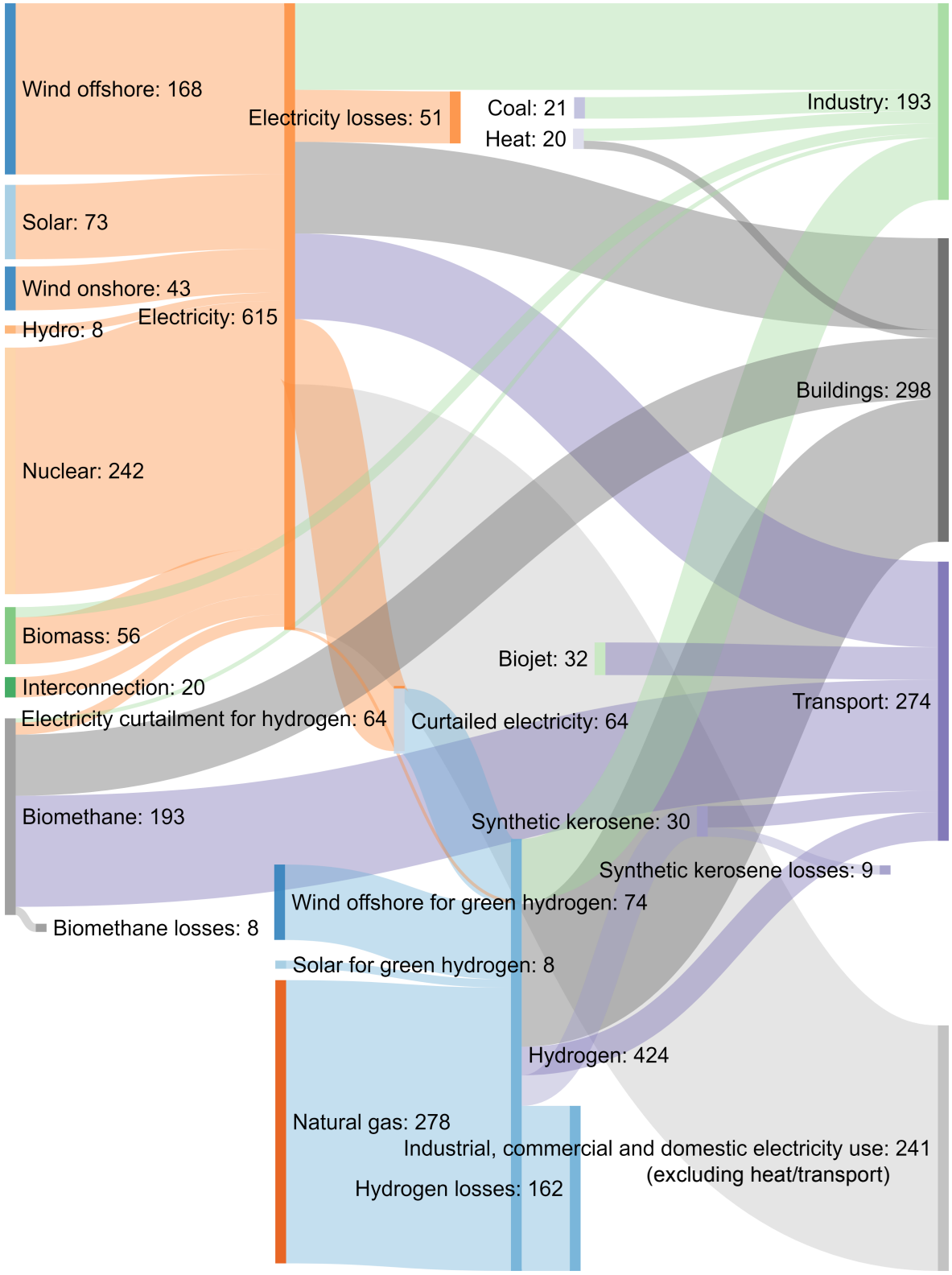
1. Energy Supply and the Role of Gas

Key Energy Supply Highlights

- Low carbon and renewable gases play a significant role in GB's energy system
- Hydrogen and biomethane supply approximately 236 TWh and 193 TWh of energy demand; these gas volumes are approximately 50% of today's gas demand
- Electricity supplies 259 TWh of the energy demand available for fuel-switching (heat and transport). Electricity supplies an additional 241 TWh of non-heat, non-transport electricity – which captures demand from space cooling, lighting, etc.
- Biomethane and hydrogen gas supply a larger share of energy demand from buildings and transport than electricity.



Sankey Diagram[60] of Energy Flows in The Balanced Scenario

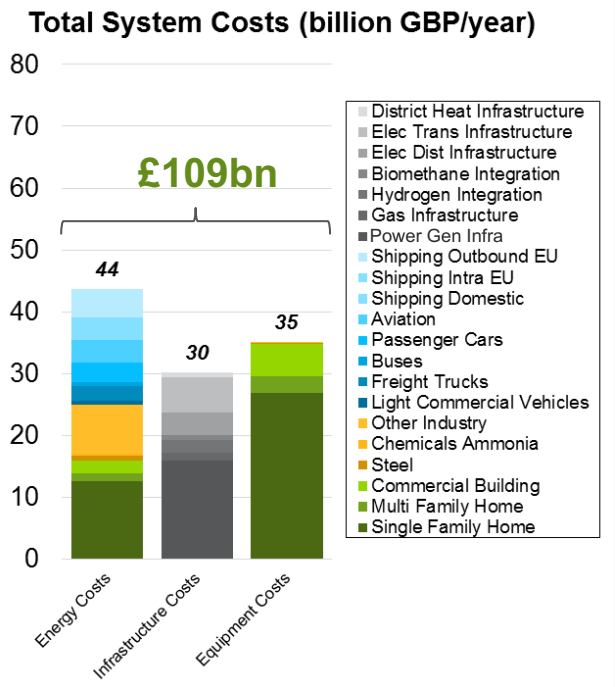


[60] The Sankey diagram above and in Section 2.2.2 are based on the same underlying data, however the version in Section 2.2.2 is a simplified version and in order for the columns of Sankey to balance a number of adjustments are required.

2. Total Energy System Costs

Key Energy System Costs Highlights

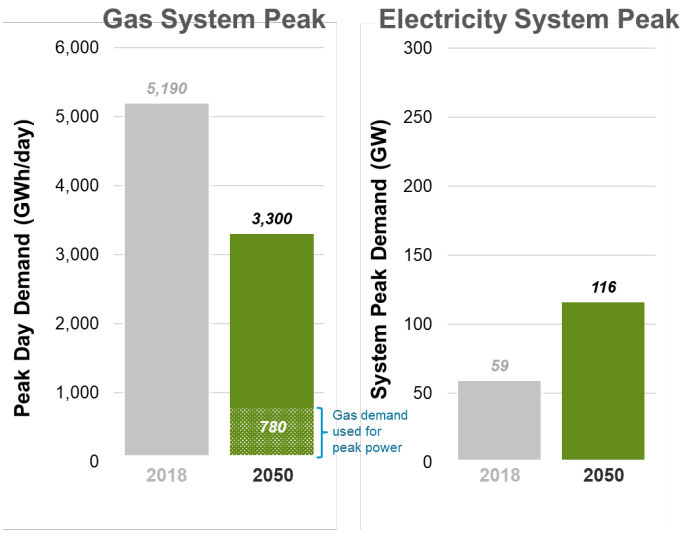
- Total energy system costs in 2050 are GBP109bn/yr.
- The largest share of cost is associated with energy costs at GBP44bn/yr., followed by end-user equipment costs and infrastructure costs at GBP35bn/yr. and GBP30bn/yr., respectively.



3. Peak Energy Supply

Key Energy Supply Highlights

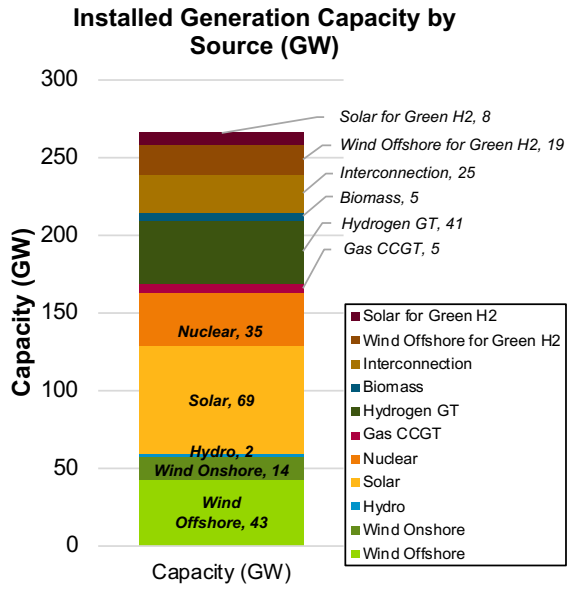
- Gas system peak demand decreases by roughly 35% from 5,190 GWh/day down to 3,300 GWh/day, with approximately 23% of gas peak being used for peak power generation. The reduction in gas peak demand is two-fold: (1) as a result of the wide-scale adoption of moderate renovation and some limited extensive renovation lowering gas demand, and (2) the widescale adoption of hybrid heat pumps.
- Electricity system peak nearly doubles increasing from 59 GW today to 116 GW. A significant portion of the electricity system peak is contributed by building heating.

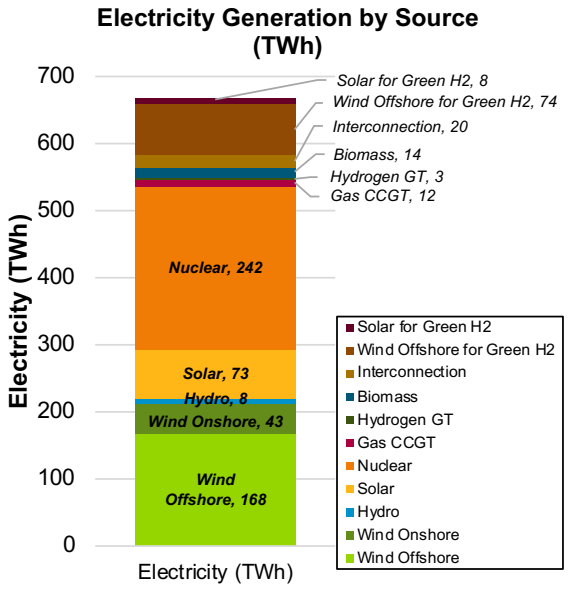


4. Power Generation

Key Power Generation Highlights

- Installed generation capacity increases from today's roughly 90 GW to 266 GW, of which 249 GW is dedicated for power generation and 27 GW for hydrogen production.
- Renewables for electricity generation account for a combined 128 GW, between solar, wind and hydroelectric power.
- Annual electricity generation increases from present level around 300 TWh to 666 TWh, including 83 TWh for dedicated hydrogen production. Nuclear power alone accounts for 36% of total electricity generation.

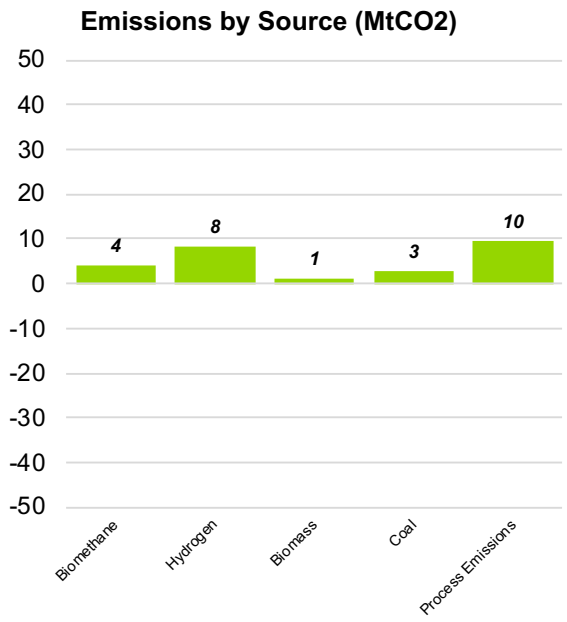




5. GHG Emissions

Key GHG Emissions Highlights

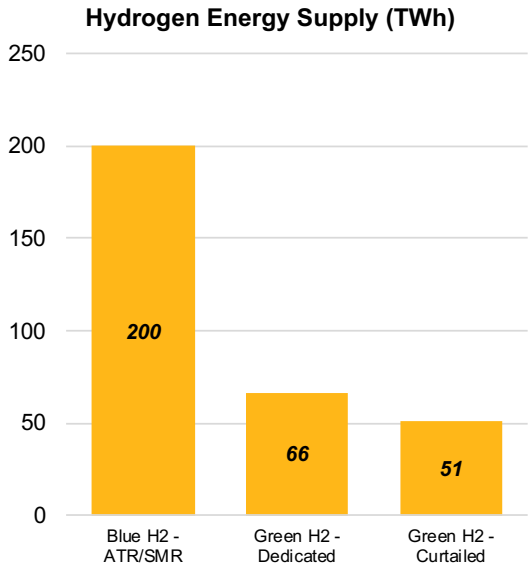
- The Balanced Scenario meets net-zero emissions in 2050.
- Residual emissions from hydrogen production via reforming of natural gas and industry are offset by 'negative emissions' from the use of biomass with CCS.
- Hydrogen emissions (8MT CO_2) primarily relate to fugitive methane emissions in upstream natural gas extraction and the incomplete capture of carbon dioxide in (Blue) hydrogen production.
- Industrial emissions (13MT CO_2) are primarily due to process emissions (10 MT CO_2) and from unabated coal use in steel making (3MT CO_2).
- We assume that around 50% of the Bio-SNG production and 100% of the biomass power (BECCS) is coupled with CCS, resulting in total negative emissions of -21 MT CO_2.

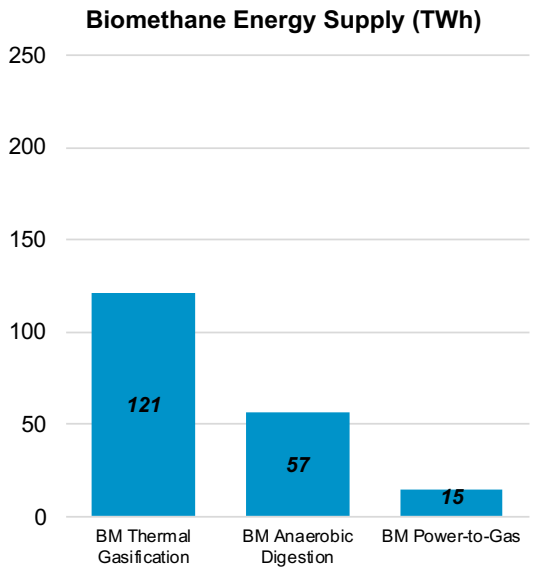


6. Low Carbon & Renewable Gas Supply

Key Gas Supply Highlights

- Around 60% of hydrogen is produced via reforming of natural gas. Of the balance, marginally more hydrogen production is supplied from dedicated renewables compared to curtailed renewables.
- Around 60% of biomethane is produced via Bio-SNG, and 30% via anaerobic digestion. biomethane power-to-gas production is marginal, representing less than 10% of biomethane supply.
- Our Balanced Scenario forecasts 509 TWh of low carbon and renewable gas supply in 2050, of which 317 TWh is Hydrogen and 193 TWh biomethane. In addition, 278 TWh of natural gas is used in hydrogen production. This represents around 65% less total gas use compared to today.

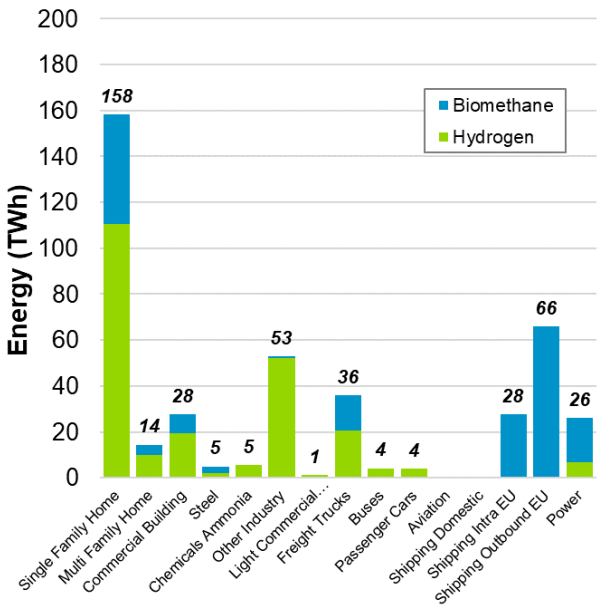




7. Low Carbon & Renewable Gas Demand

Key Gas Demand Highlights

- Gas demand across all sectors in 2050 is 429 TWh. The greatest demand is in buildings (47% of total), followed by transport (32%), power (6%) and industry (15%).
- Buildings gas demand is 200 TWh, of which 158 TWh is in Single Family Homes. Hydrogen supplies 70% of this demand.
- Shipping (Intra-EU and International) makes up the majority of low carbon and renewable gas demand in Transport (94 TWh out of 139 TWh) and is exclusively biomethane (as Bio-LNG).[61]
- 26 TWh of low carbon and renewable gases are used to provide peaking power generation, 75% of which is biomethane.
- Demand in industry is relatively modest at 63 TWh, of which 94% is from hydrogen, with only a marginal demand for biomethane (primarily restricted to processes that require Biomethane as a process feedstock).



[61] Demand for low carbon and renewable gas exists across all road transport modalities, with strongest demand in Freight Trucks (36 TWh). The relative gas shares are around 60% Hydrogen to 40% Biomethane, supplied as either CNG or LNG.

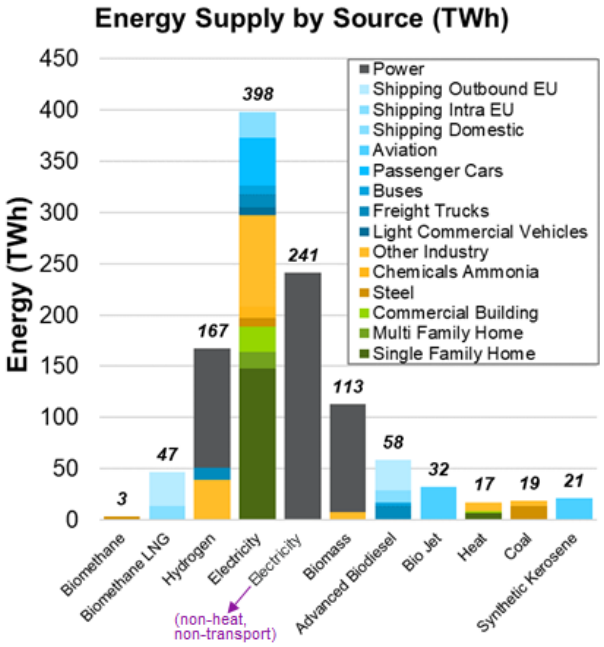
APPENDIX E. DETAILED RESULTS OF ELECTRIFIED SCENARIO

This section explores in detail the results of the Electrified Scenario. In the Electrified Scenario, low carbon and renewable gases have a limited role. In industry, some low carbon and renewable gas is necessary, as electricity cannot be an effective substitute. Low carbon and renewable gases also provide some transport fuel. Due to the increased reliance on renewable power generation, low carbon and renewable gases fuel peak power generation plants. However, no gas is used to provide heat in buildings. Instead, in this scenario, buildings use stand-alone electric heat pumps. CCUS also provides a vital contribution in this scenario.

1. Energy Supply and the Role of Gas

Key Energy Supply Highlights

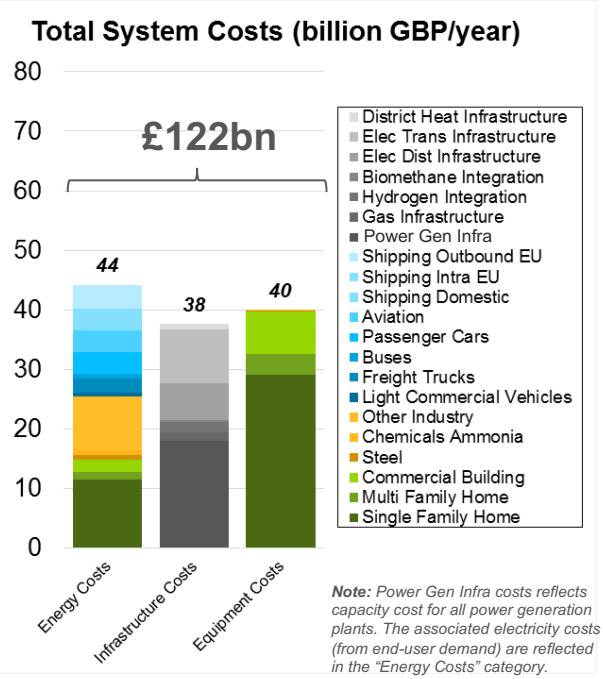
- Low carbon and renewable gases play a limited role in GB's energy system.
- Hydrogen and biomethane supply 167 TWh and 50 TWh of energy demand; these gas volumes are approximately 25% of today's gas demand.
- Electricity supplies 398 TWh (in addition to 241 TWh of non-heat, non-transport electricity).



2. Total Energy System Costs

Key Energy System Costs Highlights

- Total energy system costs in 2050 are GBP122bn/yr.
- The largest share of cost is associated with energy costs at GBP44bn/yr., followed by end-user equipment costs and infrastructure costs at GBP40bn/yr. and GBP38bn/yr., respectively.

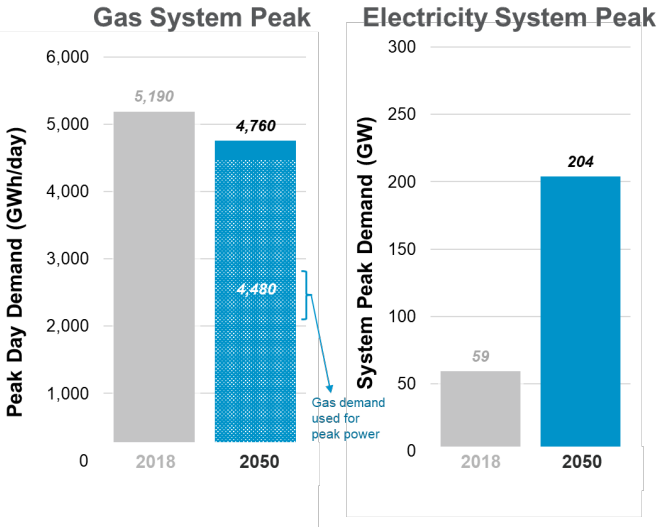


Note: *Power Gen Infra costs reflects capacity cost for all power generation plants. The associated electricity costs (from end-user demand) are reflected in the "Energy Costs" category.*

3. Peak Energy Supply

Key Energy Supply Highlights

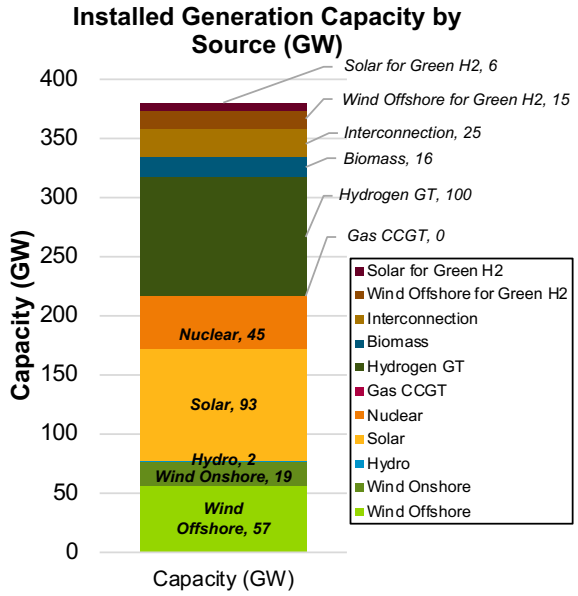
- Gas system peak demand decreases by 8% from 5,190 GWh/day down to 4,760 GWh/day, with approximately 95% of gas peak being used for peak power generation.
- Electricity system peak more than triples increasing from 59 GW today to 204 GW. The major share of the electricity system peak is contributed by building heating.

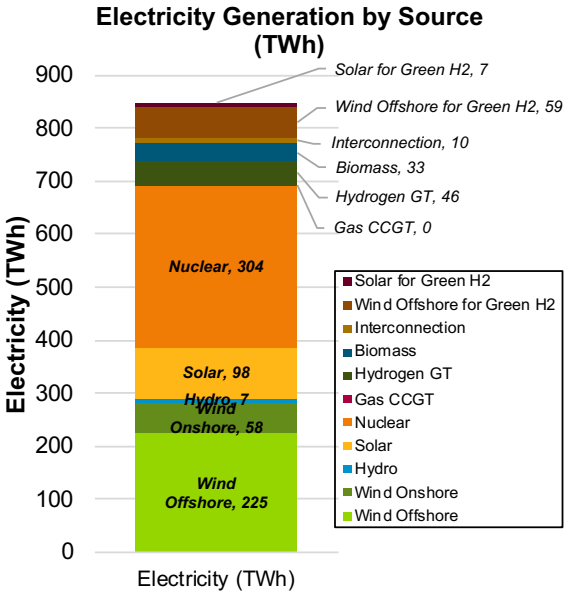


4. Power Generation

Key Power Generation Highlights

- Installed generation capacity increases from today's roughly 90 GW to 379 GW, of which 358 GW is dedicated for power generation and 32 GW for hydrogen production.
- Renewables for electricity generation account for a combined 171 GW, between solar, wind and hydroelectric power.
- Annual electricity generation increases from present level around 300 TWh to 847 TWh, including 65 TWh for dedicated hydrogen production. Nuclear power alone accounts for 36% of total electricity generation.

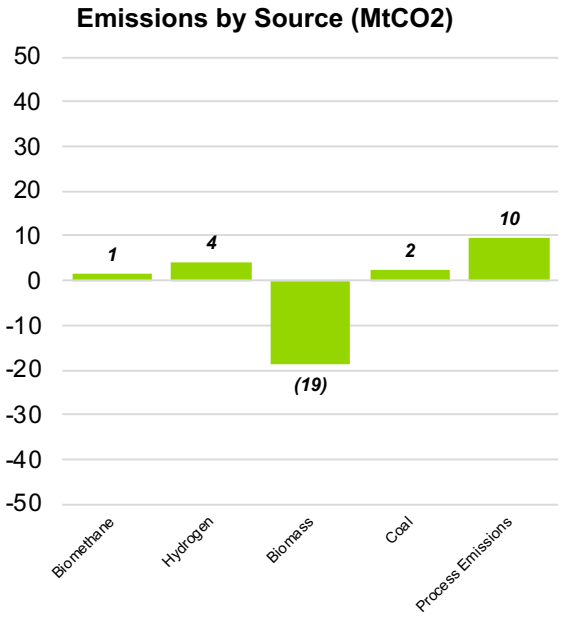




5. GHG Emissions

Key GHG Emissions Highlights

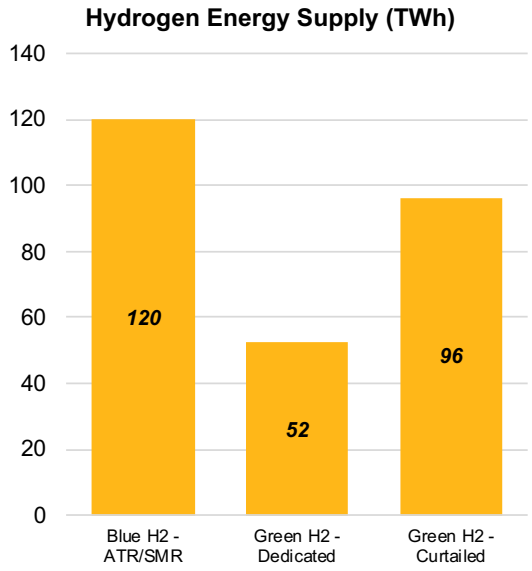
- The Electrified Scenario meets net-zero emissions in 2050.
- Residual emissions from blue hydrogen (4MT CO_2) and industry (2MT from coal and 10MT from process emissions) are offset by 'negative emissions' from the use of biomass with CCS (19 MT CO_2).

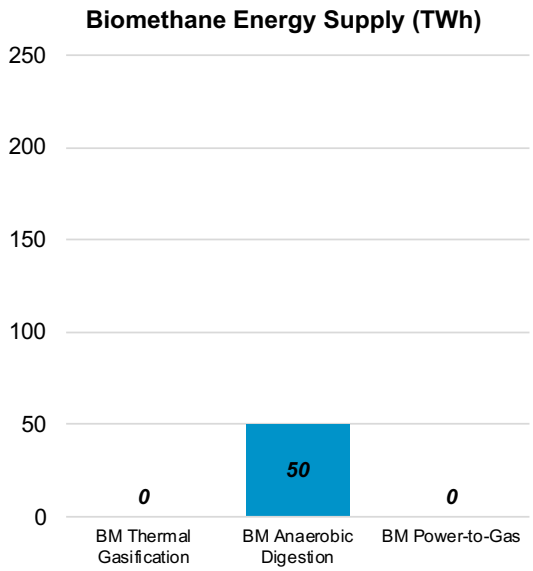


6. Low Carbon & Renewable Gas Supply

Key Gas Supply Highlights

- Around 45% of hydrogen is produced via reforming of natural gas. Of the balance, more hydrogen production is supplied from curtailed renewables than dedicated renewables.
- All biomethane is produced via anaerobic digestion. Limited biomethane demand does not result in production from Bio-SNG or power-to-gas biomethane.
- Our Balanced Scenario forecasts 318 TWh of low carbon and renewable gas supply in 2050, of which 269 TWh is Hydrogen and 50 TWh biomethane. In addition, 167 TWh of natural gas is used in hydrogen production. This represents around 80% less total gas use compared to today.

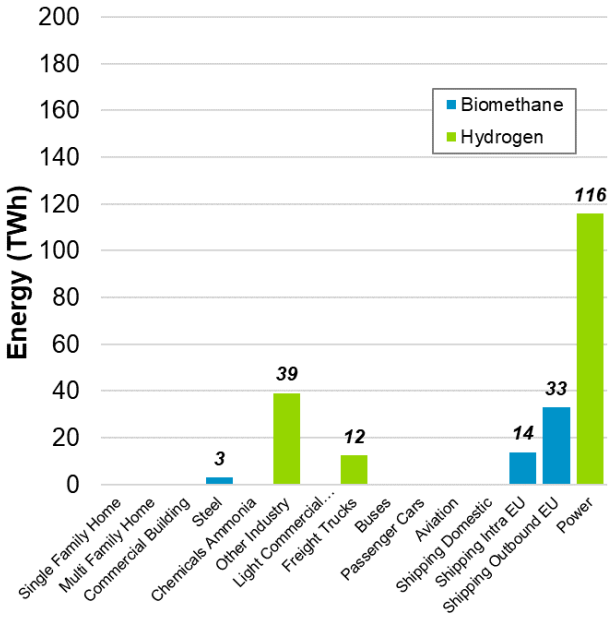




7. Low Carbon & Renewable Gas Demand

Key Gas Demand Highlights

- Gas demand across all sectors in 2050 is 217 TWh. The greatest demand is in power (53% of total), followed by transport (27%) and industry (19%).
- Power makes the majority of gas demand, with limited demand for hydrogen and biomethane in industry and transport.



8. Sensitivity: Additional Renovation

In the Electrified Scenario, we assume that all-electric heat pumps are installed alongside moderate building insulation. This sensitivity explores the possibility that insulation levels can be increased to an extensive level for all buildings with an all-electric heat pump.

The total energy system cost of this sensitivity is significantly lower than the Electrified Scenario, and the difference to the Balanced Scenario halves from GBP13bn/year to GBP7bn.

In this sensitivity, electricity generation capacity falls by 75 GW as heating demand from buildings decreases. Solar and wind generation capacity falls by 27 GW. The use of hydrogen gas turbines falls by 31 GW as peak power requirements decrease due to the improved insulation and lower peak heat demand.

Gas demand drops by almost 25% from the Electrified Scenario due to reduced hydrogen demand for peak power generation. Overall gas demand is approximately 38% of that in the Balanced Scenario.

The additional renovation has a very significant impact on both peak gas demand and peak electricity capacity required. Peak electricity falls from 204 GW in the Electrified Scenario to 160 GW. As a consequence of the reduction in peak power requirement, the gas peak demand falls over 55% to just over 2,000 GWh/day.

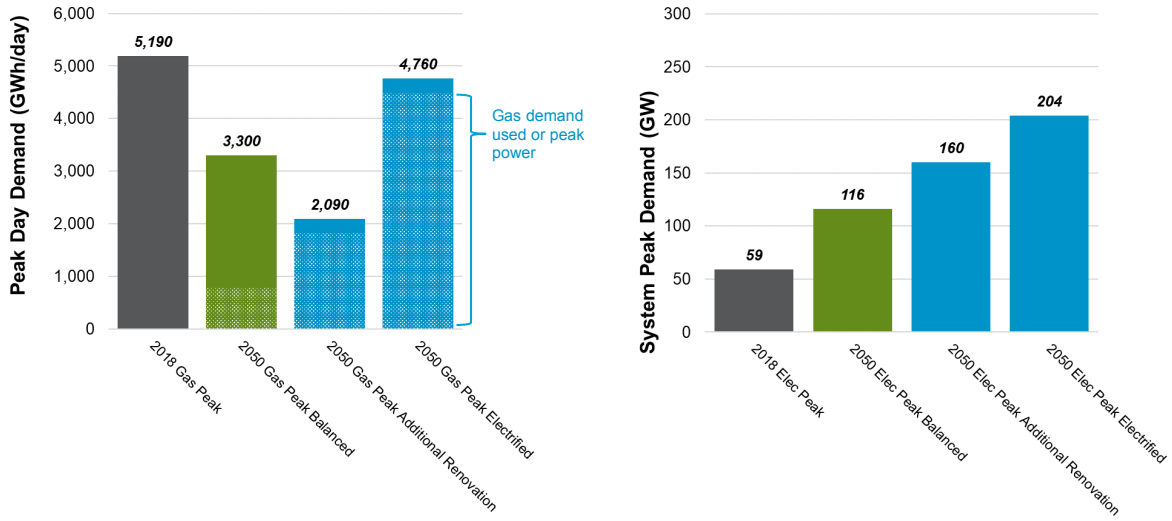


Figure 32 Additional renovation sensitivity

We have not adopted this assumption of extensive insulation in the Electrified Scenario due to the likely practical difficulties of achieving widespread implementation of the extensive building renovations required. In Chapter 5, we acknowledge that the comprehensive roll-out of moderate building renovations assumed for our Balanced Scenario may be challenging, and as a result end-users may prefer a low-carbon boiler over a hybrid heat system. While net-zero emissions are still achievable with the use of low-carbon gas boilers, overall energy system costs rise.

In the Electrified Scenario and this sensitivity, no gas is used for heating buildings. The only practical option to pursue, if the desired insulation levels cannot be achieved, is to install a much larger all-electric heat pump. This approach, together with the increased need for electricity generation and grid reinforcement, would push total energy system costs up significantly. We have therefore taken the view that moderate building insulation is a more appropriate assumption for both our Electrified and Balanced Scenarios.

APPENDIX F. MODELLING METHODOLOGY AND ASSUMPTIONS

Our modelling methodology leveraged Navigant's Energy System Model (ESM) developed for the Gas for Climate (GfC) consortium, a group of European gas transmission system operators (TSOs) and biogas producers. Navigant adapted the GfC model to assess the role of gas in net-zero GB energy system in 2050. Navigant built the ESM model in Analytica (version 5.1), developed by Lumina Systems.

The scope of our model includes four demand sectors; buildings, industry, transport and power. Power is considered a demand sector because gas supply is used in the power sector as fuel for dispatchable generation. This analysis is carried out by modelling different decarbonisation options and energy supply sources by each sector. The two scenarios; the Balanced and Electrified Scenario represent different combinations of these decarbonisation options and energy sources. The model is used to analyse the total energy systems cost under specified availabilities of biomethane, hydrogen, and biofuels. Our analysis categorises energy system costs into three categories, as illustrated below. Those costs (capital and operational) are then converted to an annual amount and presented in real terms.

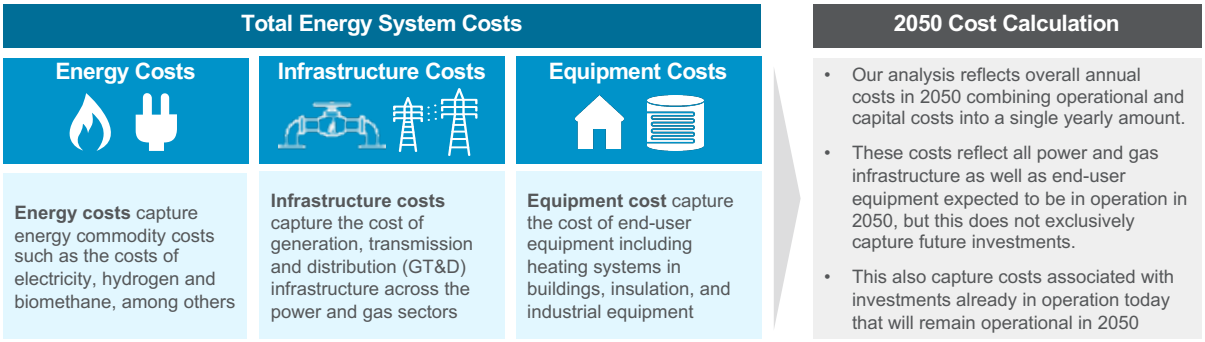


Figure 33 Energy System Cost Categories[62] [63]

The model distinguishes between several sectors, subsectors and technologies and allocates biomethane, hydrogen, and biofuels availability over these subsectors and technologies based on the lowest-cost principle. We chose the scope of our cost estimates that would allow us to perform a fair cost comparison between the two scenarios. This means, for example, that we included all energy production costs for both scenarios, so for buildings we included all heating system and insulation costs, while for transportation we excluded the costs of road vehicles, ships and airplanes because those costs would be similar in both scenarios.

[62] **Infrastructure Costs:** The full costs of building power GT&D infrastructure are recovered through both energy costs and infrastructure costs. The attribution of power infrastructure costs across 'energy' and 'infrastructure' is based on the mix of total electricity demand for (1) heat and transport and (2) non-heat / non-transport. For example, consider a hypothetical scenario with 2050 annual cost of power infrastructure of GBP10M/year. Energy costs capture the cost of electricity consumption associated with electric heat demand from buildings and industry, and electric transportation (heat and transport). If electric heat and transport demand accounts for 50% of the total load, GBP5M/year is attributed to energy costs. The remaining 50% of costs (GBP5M/year) would be attributed to the non-heat, non-transport load (such as lighting, space cooling, refrigeration, etc.). These costs are captured as infrastructure costs.

So while our analysis does not report separately the costs of non-heat, non-transport electric demand, we do quantify and capture the power infrastructure investments required to supply electricity to the total systems load.

[63] **2050 Cost Calculation:** Capital costs are converted to a levelised amount using an annuity factor based on the economic lifetime of each type of investment and a social discount rate of 5%. This 5% is intended to capture an average cost of capital across various customer sectors and private and public perspectives. Investments to achieve a net-zero energy system by 2050 will be partly done by governments, private households, businesses and investors. The 5% discount rate is intended to reflect this mix. It considers standard government borrowing rates (0-3%), common household mortgage interest rates of 4-5%, and higher expected returns for the private sector. This 5% social discount rate is consistent with the approach performed by Navigant for the *Gas for Climate* report (2019) and is also in line with the discount rate recommended by the European Commission for cost-benefit analysis according to Annex III to the Implementing Regulation on application form and CBA methodology (recommending a 5% discount rate for Cohesion countries and a 3% discount rate for other Member States).

A simplified overview of the model is shown below as well as its key bounds and characteristics.

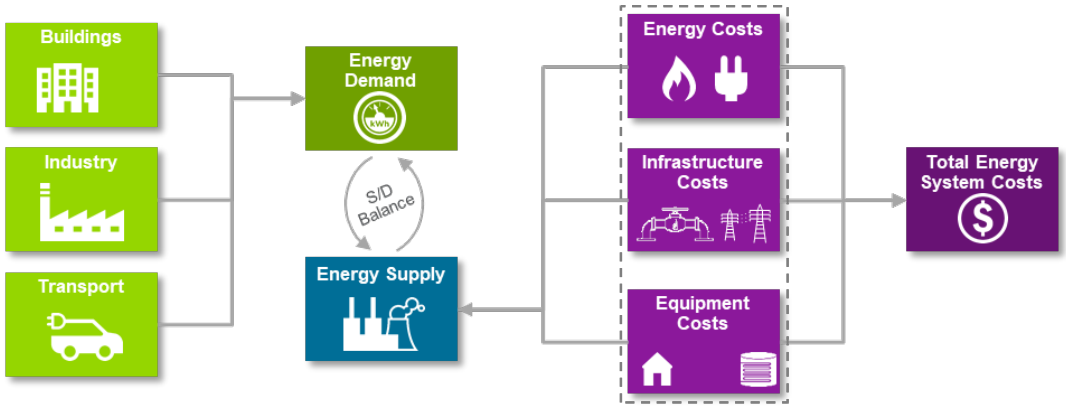


Figure 34 Simplified Overview of the Energy System Model

Characteristic	Description
Sectors	• Buildings, Industry, Transport and Power
Geographic Scope	• GB treated as a single unit; however imports are incorporated for biomass and power (interconnectors). All hydrogen is domestically produced
GHG Emissions	• Net -zero GHG emissions across the buildings, industry, transport and power sectors by 2050. Excludes emissions from agriculture, LULUCF, waste, F-gases and supply chain emissions. • Emissions price not explicitly modelled.
Key Energy Sources	• **Gas**: Hydrogen (blue: ATR/SMR and green: dedicated and curtailed renewable electricity[64]) and Biomethane (Anaerobic digestion, Bio-SNG and power-to-gas) • **Power**: Nuclear, Wind (Offshore and Onshore), Solar, storage, hydrogen, dispatchable generation included biomass-, biomethane- and hydrogen-fired gas turbines.

The analysis is performed in the model by the following steps:

1. **Energy Demand:** Calculate energy demand in buildings, industry, and transport sector based on decarbonisation options (which differ by scenario) and stock (floor stock for buildings, industrial output for industry and mileage for transport)

2. **Energy Supply:** Identify sources of energy supply that are available to meet energy demand (e.g., biomethane, hydrogen, electricity, biomass etc.). Assess maximum energy supply available (e.g., domestic biomass and imports). Model electricity generation based on the available variable renewable electricity generation and dispatchable generation.

3. **Energy System Costs:** Calculate energy system costs based on the balance of energy demand and energy supply across three cost categories: (1) energy costs; (2) infrastructure costs and (3) equipment costs.

Navigant's ESM model consists of various dedicated modules:

[64] The amount of green hydrogen produced from curtailed renewable electricity is determined from the hourly surplus electricity generated based on the power modelling of supply-demand conditions. Only a portion of the surplus electricity is assumed to be used for hydrogen production, the portion for which it is deemed to be economic. The remainder of the surplus electricity is assumed to be curtailed.

- **Buildings:** Modelling of residential and commercial energy demand for heating based on the renovation level and heating technologies.
- **Industry:** Modelling of industrial energy demand for steel, ammonia, and methanol production based on the sectoral decarbonisation options.
- **Transport:** Modelling of transport energy demand for passenger cars, freight trucks, buses, ships, and aircrafts based on the various vehicle technologies.
- **Power:** Modelling of electricity costs and demand for dispatchable power based on total electricity demand in buildings, industry, and transport, and on electricity generation from nuclear, renewables, storage, dispatchable generation and interconnectors.
- **Gas:** Modelling of renewable and low-carbon gas supply and comparison with the demand in the buildings, industry, transport, and power sectors.
- **Infrastructure:** Modelling of electricity, gas, and heat infrastructure costs

The following sections present key model assumptions across seven data input categories, as shown by the figure below. These categories relate back to the modules described above and the overall modelling methodology.

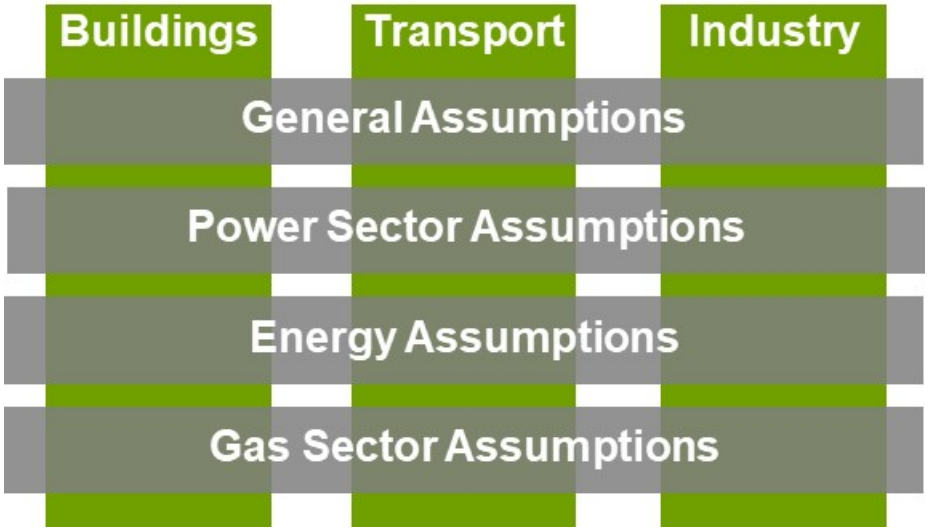


Figure 35 Data Input Categories

1. General Assumptions

Background: The demand parameters shown are used to forecast energy demand trends in the domestic sector.

Key Sources: Combination of Navigant estimations based on literature sources and industrial intelligence (typically for developing options) and third-party forecasts (for mature options). All variables are estimated for 2050. 'ASHP share of HHP capacity' is based on ASHP capacity/gas boiler capacity designed to provide baseline heat with gas boiler peak servicing.

Miscellaneous Input Parameters	Data
Bldg I Demolition rate	0.1%
Bldg | New Build Rate (%)	3.8%
Bldg | Construction Period (years)	31
Bldg | Insulation Cost Reduction (%)	50%
Bldg | ASHP Share of HHP Capacity (%)	15%
Bldg | Assumed Hydrogen Share of Energy Supply for Gas Boilers	20%

F.1.1 General Assumptions – Emissions Factors

Background: Emission factors per energy carrier are multiplied by the energy supplied per energy carrier to estimate the associated GHG emissions.

Key Sources: Electricity supply is assumed to be 100% renewable or low carbon in 2050. CCS is applied on 50% of the Bio-SNG capacity and 100%/60% of Biomass power/industry capacity respectively. A biomass combustion emission factor of 0.3564 tCO_2/MWh is assumed. Methane losses include upstream, production and transmission/distribution losses. No land-use change emissions are included for biogenic energy carriers.

Input	Value	Unit	Key assumptions	Comments
Biomethane – AD	0.028	t CO_2/MWh	Zero upstream emissions for waste and residue feedstocks. N_2O emissions for crop based feedstocks. 0.5% gas loss in AD process. 1 g/m3 gas loss resulting from incomplete combustion in CHP. Closed digestate system assumed. 0.17% gas losses in gas network.	BioGrace-II. Task 37 – Methane emissions from biogas plants. MARCOGAZ WG-ME-17-31
Biomethane – Bio-SNG	-0.071	t CO_2/MWh	Zero upstream emissions for waste and residue feedstocks. 50% CCS application with capture rate of 95%. Assumption that 40% of carbon is in SNG output and 20% is vented. Biomass combustion emission factor of 0.3564 tCO_2/MWh. 0.17% gas losses in gas network.	ETI EMSE model. MARCOGAZ WG-ME-17-31

Input	Value	Unit	Key assumptions	Comments
Additional emissions for Biomethane LNG	0.001	t CO_2/MWh	Additional emissions attributed to biomethane LNG relating to liquefaction. Baseline biomethane emissions are driven by AD and Bio-SNG supply. For LNG applications, these liquefaction emissions are also added.	SIG – Can natural gas reduce emissions from transport? WP4-1
Green hydrogen	0	t CO_2/MWh	100% low carbon electricity.	
Blue hydrogen – ATR	0.051	t CO_2/MWh	Upstream methane losses of 26.3 g CO_2/kWh. 0.17% gas losses in gas network.	Navigant calculation. CCC – The compatibility of onshore petroleum with meeting the UK's carbon budgets
Blue hydrogen – SMR	0.063	t CO_2/MWh		
Electricity	0	t CO_2/MWh	100% RES-E	
Biomass (Power)	-0.861	t CO_2/MWh-el	Zero upstream emissions for waste and residue feedstocks. 100% CCS application with capture rate of 90%. Biomass combustion emission factor of 0.3564 tCO_2/MWh.	Navigant calculation. ETI EMSE model.
Biomass (Industry)	-0.052	t CO_2/MWh-th	Zero upstream emissions for waste and residue feedstocks. 20% CCS application with capture rate of 90%. Biomass combustion emission factor of 0.3564 tCO_2/MWh.	Navigant calculation. ETI EMSE model.
Biojet	0	t CO_2/MWh	Zero upstream emissions for waste and residue feedstocks. 100% low carbon electricity.	BioGrace-II
Synthetic kerosene	0	t CO_2/MWh	100% low carbon electricity. CO_2 via Direct Air Capture.	Navigant assumption.

2. Power Sector

Background: The power generation cost and performance forecasts are used in the model to: (a) assess the variable options to supply demand against one another and (b) to provide power generation infrastructure capital and operational expenditure costs.

Key Sources: Combination of Navigant estimations based on literature sources namely 2016 IEA and IRENA and BEIS 2018 reports and industrial intelligence (typically for developing options) and third-party forecasts (for mature options). CAPEX reflect today's costs and are adjusted to 2050 based on anticipated cost-reduction. FOPEX/VOPEX are assumed for 2050. Costs are shown either as levelized production costs or wholesale costs. Biomass with CCS are shown as 2050 forecasts. Costs are excluding all taxes.

Power Technology	CAPEX (GBP/MW)	CAPEX Cost Reduction (%)	FOPEX (GBP /MW)	VOPEX (GBP /MWh)	Efficiency (%)	Lifetime (years)
Gas CCGT	864,160	0%	9,398	1.57	60%	30
Gas OCGT	530,640	0%	5,324	17.60	40%	30
Gas OCGT with CCS	774,400	30%	13,200	2.38	34%	30
Gas CCGT with CCS	2,948,000	30%	14,432	7.83	51%	30

Power Technology	CAPEX (GBP/MW)	CAPEX Cost Reduction (%)	FOPEX (GBP /MW)	VOPEX (GBP /MWh)	Efficiency (%)	Lifetime (years)
Hydrogen GT	530,640	0%	5,324	8.36	40%	30
Hard coal with CCS	0	0%	74,800	0.00	0%	30
Central PV	708,400	25%	7,084	0.00	12%	30
Wind Offshore	2,156,000	40%	81,400	0.00	45%	25
Wind Onshore	1,565,520	25%	21,510	0.00	35%	25
Hydro	1,201,200	0%	9,715	0.24	85%	50
Biomass (80% with CCS)	3,003,579	6%	148,939	26.74	31%	30
Battery Storage	616,000	25%	6,160	0.00	90%	5

Transmission and Distribution Costs: Both our Electrified and Balanced scenarios require a very large increase in electricity production. This requires large investments in electricity generation capacity but also in upgrading and expanding electricity transmission and distribution infrastructure. As shown below, these costs are significantly higher in the Electrified scenario compared to the Balanced scenario because of the higher reliance on electricity supply to meet energy needs in the Electrified scenario.

To calculate the costs for upgrading the electricity infrastructure, we apply different approaches for high voltage, medium voltage and low voltage grids.

Cost Summary	Electrified Scenario	Balanced Scenario
High Voltage	GBP 9.0 billion annually	GBP 5.7 billion annually
Medium / Low Voltage	GBP 6.1 billion annually	GBP 3.6 billion annually

High-voltage Transmission: The necessary reinforcement of the high-voltage transmission grids depends on a wide range of factors, among them the location of electricity generation, the volatility of electricity supply and demand and the type of cables used (e.g. overhead lines versus underground cables).

The e-Highway 2050[65] project calculated the necessary investments into the pan-European transmission grid for different scenarios and this study has been used to estimate costs for GB. The study focused mainly on the requirements for bulk capacities between different clusters within the EU. The “100% RES” scenario of the e-Highway study includes high levels of electrification across the EU. In this scenario large numbers of renewable electricity generation are installed that require investments in new electricity infrastructures, such as reinforced links, and increased power transmission capacity.

For the **Electrified** Scenario, Navigant calculated transmission costs for the UK, apportioned by peak demand, based on the pan-European costs developed for the 100% RES scenario. These costs are estimated to be approximately GBP3.3 billion annually.

Additionally, large investments will need to be made to integrate renewable energy into the energy system. In the Electrified Scenario, practically all generated and consumed electricity will need to be connected to the power transmission grid infrastructure. These costs are estimated to be around GBP5.7 billion annually, based on a 26GBP/MWh[66] cost for offshore wind integration. Combined, these costs amount to GBP9.0 billion annually in the Electrified scenario.

[65] www.e-highway2050.eu/e-highway2050/

[66] Agora Energiewende, Integrations costs of wind and solar power, p.36-38.

In the Balanced Scenario, the electricity transmission costs are expected to be lower than in Electrified Scenario for three reasons:

1. Annual electricity demand and peak load is materially lower in the Balanced Scenario compared to the Electrified Scenario, with the peak load being 116 GW versus 204 GW.

2. Transport of solid biomass – which is more prevalent in the Electrified Scenario – is costlier than transport of low carbon and renewable gas, therefore power plants that run on biomass will be built closer to ports and rivers and further away from demand centers. In contrast, power plants running on low carbon and renewable gas in the Balanced Scenario, can be more distributed and located more closely to areas with a high demand for electricity demand.

3. The use of power-to-gas allows useful exploitation of excess renewable generation capacity and generation capacity in remote areas. Instead of the construction of expensive transmission lines, the existing gas grid can be used for transporting the energy. Therefore, in the Balanced Scenario we adopt the cost estimates based on the "small and local" scenario from the e-Highway study to estimate the electricity transmission costs.

Transmission costs in the Balanced Scenario are assumed to be approximately GBP1.4 billion annually. The cost for integrating renewable energy system amount to GBP4.3 billion annually in the Balanced Scenario. Combined, these costs amount to GBP5.7 billion annually in the Balanced scenario.

Medium- and low-voltage Distribution: The medium and low voltage grids will require reinforcements to cope with increased electrification. As highlighted above, the resulting electricity demand, peak load, and amount of installed renewable energy generation is higher in the Electrified Scenario compared to the Balanced Scenario.

To calculate the costs for medium voltage grid reinforcements, Navigant assumes that the costs depend on peak demand and on the costs per capacity unit for different locations (urban / intermediate / rural areas). These annual medium voltage grid reinforcement costs vary between GBP18 /kW for urban areas and GBP48 /kW for rural areas.[67] The average costs per capacity unit were calculated based on the trend of population growth and the distribution of the population within urban and rural areas resulting in a blended cost of GBP30 /kW. The peak demands are based on the profiles created to represent energy required for the heating of buildings. Full electrification increases peak electricity demands, meaning higher transport capacity is required. On the medium voltage level, an indication of the average cost for additional grid capacity is available for the urban, suburban, and rural areas from a previous study on the value of congestion management in the Netherlands[68] and cross checked these figures against reports from Element Energy[69] and Mendota[70]. Navigant used these costs as an estimate for the GB electricity grid extension cost.

Navigant estimated the costs to upgrade the medium and low voltage grids in the Electrified Scenario to be around GBP6.1 billion annually, including GBP0.8 billion to integrate onshore wind and solar power production, based on an estimated GBP5 /MWh.[71] In the Balanced Scenario these costs are GBP3.6 billion annually, including GBP0.6 billion for renewables integration.

[67] Gas for Climate. March 2019: "Gas for Climate: The optimal role for gas in a net-zero emissions energy system" and cross checked with gas network company data.

[68] Navigant, 2016. Waarde van congestiemanagement (available in Dutch).

[69] https://www.nic.org.uk/wp-content/uploads/Element-Energy-and-E4techCost-analysis-of-future-heat-infrastructure-Final.pdf, pg. 92

[70] https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf, pg. 13-14

[71] Agora Energiewende, Integrations costs of wind and solar power, p.36-38.

3. Energy

F.3.1 Energy – Biomass Supply

Background: The Biomass Supply parameters are used in the model to constrain the generation potential for the Biomass conversion technologies: including Biomethane from anaerobic digestion, Biomethane from thermal gasification (Bio-SNG), Advanced diesel (FT and HVO/HEFA) and Biomass Heat/Power.

Key Sources: The CCC's Biomass in a Low Carbon Economy report forms the basis of the assumptions for solid biomass feedstock potential. Biomethane from anaerobic digestion potential are based on data provided by ADBA.

Input	Value	Unit	Key assumptions	Comments	Sources
Solid biomass (including biomass fraction in waste)	281	TWh (primary energy)	UK feedstocks: 126.2 (Energy crops: 35, Forest residues: 43, Agricultural residues: 10.8, Waste wood: 24, MSW: 13) Imports: 155 - 404	Feedstocks suitable for: Bio-SNG, Advanced (FT) diesel or Biomass heat/power Global Governance & Innovation Scenario (Scenario 4)	CCC
Biomethane from AD	57	TWh (biomethane)	Wet manure: 20, Crops: 13.1, Food waste: 6.4, Landfill gas: 2.9, Straw: 4.2, Sewage sludge: 5.3, Other: 5	ADBA estimates are for 2032 and flatlined to 2050 CCC estimates are average of Low/High ranges Assumes that crops are cultivated sustainably (e.g. via improved agronomic practises that maximise energy output/yield per land area)	ADBA, CCC
Waste oils	5.3	TWh (primary energy)	Tallow: 1.9, UCO: 2.2	Feedstocks suitable for: Advanced diesel (HEFA/HVO)	CCC

F.3.2 Energy – Fuel Costs

Background: The fuel costs are used in the model to: (a) asses the variable options in demand segments against one another and (b) together with demand volume estimate the total costs associated for a given option (e.g. energy demand X fuel cost for airlines).

Key Sources: Combination of Navigant estimations based on literature sources and industrial intelligence (typically for developing options) and third-party forecasts (for mature options). All variables are estimated for 2050. Costs are shown either as levelized production costs or wholesale costs. Costs are on LHV basis and excluding all taxes.

Input	Value	Unit	Key assumptions	Comments	Sources
Biomethane - AD	50	GBP/MWh	x2 500 m3/r biogas output plants feeding 1,000 m3/hr upgrader		Navigant - Gas for Climate (Based on CIB – Italian Biogas Association, Biosurf)
Biomethane - Thermal Gasification	59	GBP/MWh	200 MWhSNG output	Blended cost of production with/without carbon capture	Navigant - Gas for Climate – adjusted for UK feedstock mix. (Based on: GoGreenGas, GoBiGas, Ecofys & E4Tech)

Input	Value	Unit	Key assumptions	Comments	Sources
Biomethane - PtG from Hydrogen	93	GBP/MWh	Based on dedicated H2 production (3100 FLH for electrolyser, 6200 FLH for methanation reaction). Hydrogen cost: 54 EUR/MWh. Installed Methanation reactor CAPEX: 600 EUR/kW (HHV-SNG-output). OPEX: 8% of initial CAPEX/y; including all replacement costs. Hydrogen storage costs: 15 EUR/MWh Ratio SNG_{out}/$Hydrogen_{in}$: 1.35		Navigant calculations and ENEA Consulting
Additional cost for Bio-LNG use	11	GBP/MWh	Based on 3.10 GBP/MBTU	Uplift to Biomethane costs. Likely to be conservative value	DNV
Biofuel - HVO/HEFA	66	GBP/MWh	Based on waste oils	Drop-in diesel like fuel	Navigant - Gas for Climate
Biofuel - FT	75	GBP/MWh			Navigant - Gas for Climate
Synthetic Kerosene	83	GBP/MWh		Based on CO_2 capture and Green H2 production	Navigant - Gas for Climate
Biomass	26	GBP/MWh		Generic price for wood pellets delivered	Navigant - Gas for Climate (cross-referenced against ETI Biomass Logistics 2050 project)
Hydrogen - Curtailed	20	GBP/MWh	FLH: 2000 h/y Electricity cost: 0 EUR/MWh	Based on otherwise curtailed power. Same base assumption as for dedicated electrolysis. Based on average plant (in terms of FLH)	Navigant calculation
Hydrogen - Dedicated	48	GBP/MWh	FLH: 2000-5000 h/y Electricity cost: 15-40 EUR/MWh Installed plant CAPEX: 423 EUR/kW (electricity input) OPEX: 3% of initial CAPEX/y; including all replacement costs. Efficiency: 80% (LHV)	Dedicated PEM electrolysis. Value based on scenario analysis using assumption ranges	Various sources
Hydrogen - ATR + CCS	48	GBP/MWh	Natural gas price: 37 EUR/MWh. 95% CO_2 capture rate	Value based on scenario analysis using assumption ranges Recalculated based on literature source	Jakobsen & Åtland, 2016. Concepts for Large Scale Hydrogen Production
Hydrogen - SMR + CCS	52	GBP/MWh	Natural gas price: 37 EUR/MWh. 90% CO_2 capture rate	Value based on scenario analysis using assumption ranges Recalculated based on literature source	Jakobsen & Åtland, 2016. Concepts for Large Scale Hydrogen Production
Coal	8	GBP/MWh	2035 price for UK, Central Case		BEIS
Natural gas	33	GBP/MWh	2040 price, New Policies scenario		IEA

4. Gas Sector

F.4.1 Gas Sector – Natural Gas & Biomethane

Background: The costs associated with transporting gases in the network transmission system: (a) maintenance investments for the existing natural gas infrastructure and (b) biomethane transmission costs (relates to compression only), and the estimated costs of running the distribution network. Costs for biomethane are assumed to be the same as natural gas.

Key Sources: TSO maintenance costs are derived per household connected to gas grid. Average distance of a biomethane molecule travelled in the transmission/distribution systems are estimated at 300/38 km respectively. We calculate cost for capacity not for actual load (i.e. in effect this means calculating with 8,760 hours/year).

Input	Value	Unit	Key assumptions	Comments	Sources
Households connected to gas grid	23.9	Million			ENA
Maintenance costs transmission gas grid	95	Million GBP/year	Exclusive of OPEX		National Grid
Biomethane Transmission costs (CAPEX)	3.98	GBP/MWh/ 300 km			Navigant calculation based on data provided by National Grid
Biomethane Transmission costs (OPEX)	1.97	GBP/MWh/ 300 km	Compression costs 0.8 EUR/MWh	Pipeline costs and compressor costs OPEX only as no change needed. Average distance between inlet compressor and boosting station is 104 km (National Grid), hence there are 2.9 compressions per 300 km	Navigant calculation based on data provided by National Grid (and SNAM)
Biomethane Distribution (CAPEX, REPEX, OPEX)	2.93	GBP/MWh/ 38 km			Navigant calculation based on data provided by the UK gas networks
Thermal gasification integration cost	1.50	GBP/MWh	Grid connection and injection (no compression assumed)		Navigant - Gas for Climate
AD Biomethane integration cost	8.54	GBP/MWh	Grid pipeline, connection and injection		Navigant - Gas for Climate
Gas infrastructure decommissioning costs	1.24	Billion GBP/year	Costs averaged over 20 years	Cost for Wales & West Utilities was based on the gas networks average per customer	Navigant calculation based on data provided by Cadent, NGN and SGN

F.4.2 Gas Sector – Hydrogen

Background: The Hydrogen Integration costs reflect the cost of hydrogen injection and transmission to local distribution centers via high pressure pipelines. These are standalone costs, next to hydrogen production costs. The total hydrogen integration cost is calculated by multiplying the cost per MWh of hydrogen and calculated volume of hydrogen in the system. Distribution costs are additional.

Key Sources: Average distance of a hydrogen molecule travelled in the system is estimated at 300 km. The costs are calculated as average between refurbishment and new infrastructure costs (pipeline costs making up for the difference). We assume output pressure of 30 bar from the hydrogen production unit. We calculate cost for capacity not for actual load (i.e. in effect this means calculating with 8,760 hours/year). Distribution costs are based on biomethane costs, adjusted by 20% for a drop in network capacity.

Input	Value	Unit	Key assumptions	Comments	Sources
Pipeline distance	300	km	Average for the UK	Average distance H2 molecule would travel in the NTS	National Grid
CAPEX new pipeline	1.78	Million GBP/km	48" pipeline, 5% discount rate, 40 years lifetime	Navigant calculations based on ECN hydrogen pipeline tool	Checked against Gasunie, National Grid, SNAM and OGE figures
CAPEX retrofitted pipeline	0	Million GBP/km	48" pipeline, OPEX only as refurbishment investment costs for the pipeline itself are negligible	Costs for refurbishment captured in cost of compressors and gas meters	Navigant assumption
FOPEX pipeline	0.10%	Of non-annualized CAPEX	Does not include cost for compression		Gasunie estimation
Levelized CAPEX compressor	0.26	GBP/MWh H2 (LHV)	Ratio 1.5% between el power (compressor) / transported energy (hydrogen). Compression from 30bar to 80bar 1500 EUR/kW el compressor power, compressor adiabatic efficiency 85%	Excluding energy costs for compression. Average distance between inlet compressor and boosting station is 104 km (National Grid), hence there are 2.9 compressors per 300km	Gasunie data
Levelized OPEX compressor	4%	Of non-annualized CAPEX	Compression costs homogenous regardless whether this is inlet or boosting station. Energy cost for compression 52 EUR/MWh	Average distance between inlet compressor and boosting station is 104 km (National Grid), hence there are 2.9 compressions per 300 km	Gasunie and US DOE
Levelized cost gas metering station	0.004	GBP/MWh (LHV)	CAPEX 540 EUR/MW (H2) flow capacity. OPEX negligible	There is metering station at every compression or boosting station, hence 2.9 metering stations per 300 km	Navigant calculation and FNB Gas
DSO Operation and Integration cost	3.69	GBP/MWh/38km	Based on biomethane cost uplifted by 20% due to assumed drop in capacity for hydrogen		Navigant calculation based on data provided by the UK gas networks

5. Buildings

Background: Building technology costs from heating systems and insulation costs are used to determine total costs from the building sector. The number of homes requiring insulation is based on the mix of homes using gas or electricity for heating. Homes using gas incur lower insulation costs from a "shallow retrofit", whereas homes using electricity incur higher insulation costs from a "deep retrofit".

Key Sources: The technology costs used are based on recent reports and desktop research and normalised to a typical single family home with a floor area of 99 m^2 and a six-dwelling multi-family block of flats.

Input	Value	Unit	Key assumptions	Comments	Sources
Single family home – UK inventory	2,749	Million m^2	Assumes an average floor area of 99 m^2/household		Calculated based on data from EU Buildings Database (European Commission)
Multi family home – UK inventory	402	Million m^2	Assumes an average floor area of 99 m^2/household		Calculated based on data from EU Buildings Database (European Commission)
Commercial building – UK inventory	971	Million m^2	Assumes an average floor area of 99 m^2/household		Calculated based on data from EU Buildings Database (European Commission)
ASHP (Retrofit/New)	73/82	GBP/m^2	Typical system cost GBP8-10k	Data provided for Single family homes (67% of total stock)	Energy Saving Trust
GSHP (Retrofit/New)	128/128	GBP/m^2	Typical system cost GBP10-18k New installation costs assumed as per Retrofit	Data provided for Single family homes (67% of total stock)	Energy Saving Trust
HHP (Retrofit/New)	62/77	GBP/m^2		Data provided for Single family homes (67% of total stock)	Element Energy for BEIS (2018)
DH (Retrofit/New)	64/127	GBP/m^2	Dense Urban Area installation cost per household		ETI District heat networks in the UK - potential, Barriers and Opportunities (2018)
Single family home insulation (Shallow/Deep)	5.9/10.5	GBP/m^2	Costs annuitized over 30 years		Cambridge Architectural Research for BEIS (2017)
Multi family home insulation (Shallow/Deep)	5.7/8.0	GBP/m^2	Costs annuitized over 30 years	Based on 6 x 60m^2 flats in a single block	Cambridge Architectural Research for BEIS (2017)
Commercial building insulation (Shallow/Deep)	3.2/4.6	GBP/m^2	Costs annuitized over 30 years		Based on Navigant - Gas for Climate

6. Transport

Background: Transport costs are based on the forecasted energy demand in transport per modality and transport related costs in 2050. This is calculated by multiplying the distance per modality/fuel carrier in 2050 (km) with the specific fuel efficiency (MWh/km) and transport related costs per fuel carrier (GBP/km). Technology costs include: CAPEX, OPEX, fuel station costs and infrastructure costs. Min./max. technology bounds are set for each modality to determine the distance travelled.

Key Sources: Costs are made up of Capex (annualized Capex for the vehicle – not included for aviation or shipping), Opex (vehicle related O&M including fuel consumption), Fuel station costs (costs related to the fuel station, including hook-up/supply) and Infrastructure costs (costs to get the fuel to the station, e.g. Hydrogen infrastructure or power lines). Shipping and aviation costs are treated differently (e.g. Capex is not included, fuel stations and infrastructure costs are zero for liquid fuels).

Input	Value	Unit	Key assumptions	Comments	Sources
Passenger cars	288.8	Billion km	2050 forecast	Urban and Non-urban travel	IEA Mobility Model (MoMo)
Light Commercial Vehicles	41.2	Billion km	2050 forecast	Urban and Non-urban travel	IEA Mobility Model (MoMo)
Freight trucks	28.9	Billion km	2050 forecast. Includes heavy and medium freight trucks	Urban and Non-urban travel	IEA Mobility Model (MoMo)
Buses	13.7	Billion km	2050 forecast. Includes buses and mini-buses	Urban and Non-urban travel	IEA Mobility Model (MoMo)
Aviation	483	Billion km	2050 forecast. Includes domestic and international travel	Focus is on passenger travel. Freight is included but in less detail	IEA Mobility Model (MoMo)
Shipping	118	TWh/year	UK share of 2050 energy demand is 20% (based on IEA). Domestic: 100% electric, Intra EU: 50% electric, 50% Bio-LNG, Outbound: 100% Bio-LNG		Transport & Environment roadmap for EU shipping IEA Mobility Model (MoMo)
Fuel efficiency	-	MWh/km	Specific to each modality and fuel carrier		Navigant - Gas for Climate
Transport cost	-	GBP/km	Specific to each modality and fuel carrier		Navigant - Gas for Climate
Technology min./max. bounds	-	%	Specific to each modality and fuel carrier		Navigant - Gas for Climate

7. Industry

Background: Within the analysis, industrial sectors are considered which are expected to have a potential for significant gas usage in 2050. For these industries investment costs and energy use are considered for different technologies. Industrial sectors considered in detail are Iron & Steel and Ammonia.

Key Sources: The key assumption are the industrial sectors under consideration and the production development towards 2050 (assumed constant). In addition, it is assumed that technologies currently under development (e.g. the steel technology Iron Bath Reactor Smelting Reduction) will develop to commercial application in 2050.

Input	Value	Unit	Key assumptions	Comments	Sources
Iron & Steel activity	8.8	Million tonnes	Activity assumed constant towards 2050		EUROFER 2018 Steel figures
Ammonia activity	0.9	Million tonnes	Activity assumed constant towards 2050		EU ProdCom database
Energy use	Various	MWh/t Steel	New technologies based on expected energy use for full scale applications	Based on industrial work for European and German Governments, UK BEIS and EUROFER	Various sources
Investment costs	Various	GBP/t Steel	Investments costs for 2050 for full scale applications	Based on industrial work for European and German Governments, UK BEIS and EUROFER	Various sources

Input	Value	Unit	Key assumptions	Comments	Sources
Activity emissions	Various	t CO_2/t Steel	Expected 2050 emission factors	Based on industrial work for European and German Governments, UK BEIS and EUROFER	Various sources

APPENDIX G. LOW REGRET ACTIONS

We have identified a set of near-term actions that are important in decarbonising the energy system, with a specific focus on actions that apply to the gas networks. We term these "low regret actions". We reflected the feedback provided by the EAG at the third stakeholder workshop held on 20 June 2019 when developing these actions.

The actions are categorised as "High", "Medium" or "Low" according to the level of participation of the gas networks. A concise summary of these actions is provided below.

1. 'High' involvement of gas networks

ACTION 1. Develop a joint gas network company technical plan and programme for redeployment of GB gas grid infrastructure for Hydrogen

Category	Assessment
Action description	• GNCs (GDCs and National Grid) to produce an agreed future gas network plan and programme of work to use/adapt/repurpose the existing high pressure transmission and distribution gas grid infrastructure to facilitate a decentralised hydrogen economy evolution, including an assessment of future CO_2 infrastructure needs and the role that GNCs can play. • To help inform this work, National Grid will evaluate detailed network capacity requirements of the NTS transition to hydrogen at a regional level. This will include operational aspects of hydrogen deployment, such as the potential implications on linepack and network management in the context of a vision of the "Gas transmission network control room of the future". • This action also links to other Low Regret Actions on: o Gas separation technology testing; and o Conducting trials to repurpose high pressure networks for Hydrogen; and o Hydrogen storage development
Importance	• Potential to accelerate grid decarbonisation, facilitate decentralisation of gas supply and use, minimise short term storage needs, decarbonise gas power production, enable appropriate high pressure network hydrogen ready investments (compressors, valves etc.), minimise disruption (wayleaves, planning) and costs. • There is a need for the GNCs to demonstrate their full support/'buy-in' to the future proofing of the existing network as the most cost effective and least disruptive way to deliver the UK governments 2050 targets in such a way as to minimise the behavioural changes needed to reduce emissions.
GNC involvement	• Set-up a 'Gas Grid Reuse and Repurpose' project team (GGRR) consisting of senior technical representatives from all GNCs and chaired by the ENA. • The GGRR remit will be to develop an agreed detailed technical plan and program of works for gas network restructuring to 2040. This work will also incorporate outputs of parallel projects assessing future hydrogen storage needs and potential for gas separation technology deployment.
Other stakeholders	• BEIS, Infrastructure and Projects Authority, Ofgem.
Timeline	• 2020 – 2023
Costs	• c. GBP5-8 million

ACTION 2. Hydrogen gas separation technology demonstration at Hydrogen cluster(s)

Category	Assessment
Action description	• Hydrogen gas separation technologies are widely deployed globally, although typically at 'refinery-scale'. Testing gas separation technologies at 'hydrogen cluster-scale' is necessary to demonstrate proof of concept. Gas separation technology options include: o Pressure swing absorption o Cryogenic separation o Membrane separation (e.g. Palladium membrane) o Electro-chemical o Potentially a hybrid approach involving several technologies, e.g. chemical conversion
Importance	• Application of gas separation technologies can enable the blending of (high) shares of hydrogen with natural gas in the high pressure transmission system and their subsequent extraction to meet end consumer requirements. This would significantly reduce high pressure infrastructure complexity for the introduction of hydrogen since existing assets can be more readily deployed. • Application of gas separation technologies may enable end-user customised solutions. • It is important to understand any possible cascade effects on downstream (post separation) consumers.
GNC involvement	• Cross-industry engagement to agree on next steps, project co-ordination and provision of gas infrastructure for testing. Proposed next steps include: o Phase 1: Evidence building and testing end-user solutions at small-scale to prove technical feasibility and develop mitigation measures required. o Phase 2: Set-up demonstration projects to test commercial feasibility of end-user solutions at hydrogen cluster(s). Possible use of HyDeploy (Keele University) project.
Other stakeholders	• BEIS, cluster operators, gas separation technology providers, HSE, hydrogen gas suppliers, industry (or other end-users), Ofgem.
Timeline	• Phase 1: 2019 – 2024 (3 yrs max.) • Phase 2: 2025 – 2030 (3 yrs max.)
Costs	• Phase 1: GBP1 million (partly borne by technology providers) • Phase 2: GBP3-5 million (based on use of HyDeploy system)

ACTION 3. Conduct trials to repurpose high pressure networks for Hydrogen

Category	Assessment
Action description	• Following the proof of concept works already carried out (under HyNTS) it is necessary to conduct trials of the high pressure hydrogen transmission in a representative section of the network system. In scope, are assessment of the impacts on piping and system equipment, and operations aspects such as gas compressor performance at various hydrogen blends and potential linepack issues associated with hydrogen deployment. Also to be assessed are the benefits of adding limited amounts of oxygen to mitigate the tendency for hydrogen to attack the oxide layer in steel pipework which reduces its ductility.
Importance	• To demonstrate the gas technical, safety and operational case regarding transmission of hydrogen in steel pipework.
GNC involvement	• National Grid to project manage extended high concentration hydrogen trials and subsequent forensic examinations of pipework and system equipment.
Other stakeholders	• HSE, IGEM.
Timeline	• 2019 – 2022
Costs	• c. GBP5-8 million

ACTION 4: Examine future Hydrogen storage needs and associated commercial risk

Category	Assessment
Action description	• Examine the potential future seasonal storage requirements for hydrogen clusters and hydrogen-based power production and the means of funding.
Importance	• Security of supply: o UK currently has 1.4bcm (1.8% of 2016 consumption) of storage capacity in medium term salt caverns. There is no long-term seasonal storage (following Rough closure). o Supply of seasonal hydrogen via Interconnector or import pipelines cannot be relied on at this time. o Storage of hydrogen will be needed in later years as demand from buildings increases. o Storage capacity typically takes 7 years to develop and is unlikely to happen if solely left to the market.
GNC involvement	• Gas Grid Reuse and Repurposing (GGRR) team to examine potential long-term hydrogen supply and demand forecasts, identify candidate storage sites and develop budgeted plans for short-listed strategically located storage facilities. The H21 project to serve as input to this assessment (in the context of hydrogen storage in Yorkshire's deep salt caverns). • Contribute to stakeholder discussions on funding means.
Other stakeholders	• BEIS and Ofgem to examine means of commercial risk mitigation due to potentially low summer/winter spark gap differentials for storage owners and funders. • Offshore drilling sector to contribute to costing and logistics. • Infrastructure and Projects Authority to link into UK Government.
Timeline	• 2021 – 2022/23
Costs	• c. GBP5-8 million

ACTION 5: Standardise gas network connection requirements

Category	Assessment
Action description	• To develop a common specification for distributed gas connection and injection to the distribution networks across GDNs - so called Gas Entry Unit (GEU) requirements. • To develop a single streamlined application process preferably similar to that used for NTS connection requests. • The immediate priority is to standardise requirements for biomethane access, although it is also important to future-proof to cover hydrogen grid access.
Importance	• Capital costs for the design, build and installation of equipment for connection and injection of gas to the distribution networks are a significant cost component, particularly for biomethane projects with low flow volumes, hence reduced revenues. Lack of standardisation across GDNs is estimated to add a premium of up to GBP90k per connection to overall biomethane project costs,[72] which adversely impacts the overall business case. • Evaluating hydrogen gas connection requirements in advance of subsequent GB deployment mitigates potential future issues.
GNC involvement	• Initiate and manage a cross-industry consultation to assess network connection options with the overall aim of realising cost savings for injectors, taking on board any learnings from Project CLoCC[73] (facilitating lower cost gas connections to the National Transmission System). • Align GEU designs across GDNs through the creation of revised IGEM TD/16 and TD/17 standards for biomethane connection. • Develop IGEM standards for hydrogen network connection.
Other stakeholders	• Biomethane and hydrogen producers, industry associations (ADBA, REA), GEU manufacturers, IGEM.
Timeline	• Planning 2020 – 2021. Implement 2021+
Costs	• Several GBP100,000s

[72] Element Energy (2017), Distributed gas sources, Final report for National Grid Gas Distribution Ltd, SGN, Wales and West Utilities

[73] http://projectclocc.com/

ACTION 6: Implement grid capacity solutions to facilitate increased biomethane injection

Category	Assessment
Action description	• To assess and implement innovative solutions to manage the balance of supply and demand on the gas network in a more flexible manner. Potential solutions include: o In-grid compression of gas to higher tiers o Interconnection of networks o Smart management of network pressure (via pressure monitoring) o Gas storage during times of low demand o Deployment of decommissioned network access points and gas compression facilities (profiled production in line with demand upstream at the anaerobic digestion sites)
Importance	• The maximum injection capacity is limited to minimum demand downstream of potential gas injection point. However, the closest network segment to a distributed gas production facility may not have sufficient capacity for injection, particularly in summer months when gas demand is low. • A new pipeline connection to a higher gas tier is generally not considered a cost-effective solution for biomethane producers when developing projects. • Network capacity constraints are cited by industry as a key barrier to the development of biomethane projects injecting to the distribution network (many 'low-hanging fruit' injection points are already taken). In addition, for existing biomethane plants network capacity constraints can lead to biomethane 'flaring'.
GNC involvement	• Further testing of potential solutions, building on existing projects. These include Project CLoCC, which aims to facilitate lower cost gas connections to the National Transmission System. • GNCs to develop an interactive on-line mapping tool to identify potential connection points and match this with current/planned biomethane supply potential. • Cross-industry engagement to identify commercial models to share costs of solutions. • GNCs to identify decommissioned network access points and gas compression facilities.
Other stakeholders	• BEIS, biomethane producers/industry associations (ADBA, REA), Ofgem.
Timeline	• 2020 +
Costs	• <GBP100,000 to identify decommissioned network access points and gas compression facilities. • GBPmillions for field trials to test potential solutions. • Low GBP10s of millions to implement new commercial models.

ACTION 7: Develop plans for fossil gas reforming hydrogen demonstration projects

Category	Assessment
Action description	• To develop and build natural gas based blue hydrogen production demonstration plants with CCS. Both ATR and SMR technologies should be demonstrated to enable a comparison of the two technologies to be made.
Importance	• To demonstrate technical and commercial viability of blue hydrogen production with CCS and incorporate learnings into Next of a Kind plants. • To facilitate techno-economic and GHG savings performance comparison of ATR and SMR technologies, hence a minimum of two projects to be developed. • To support hydrogen end-use demonstration (e.g. in industry, transport or buildings). • To develop and deploy CO_2 transport and storage capacity.
GNC involvement	• GNCs to select sites for the demonstration plants. It is recommended that the existing hydrogen projects (Aberdeen Vision, H21, HyNet, Project Cavendish) are prioritised. • GNCs to further support the process by taking a co-ordinating role. Activities to include: selection of technology providers, provision of infrastructure for hydrogen offtake, identifying offtake contracts.
Other stakeholders	• BEIS, HSE, EA, local planning.
Timeline	• (2020)/2021 – 2023
Costs	• c. GBP15-20 million (of overall blue hydrogen demonstration plant costs) for each project.

ACTION 8: Explore opportunities to reduce fugitive methane emissions

Category	Assessment
Action description	• To assess and explore opportunities to reduce fugitive methane emissions arising from biomethane production and from transporting (bio)methane across the gas networks.[74] This will be achieved through a combination of desk-based research to improve the evidence base, followed by live trials to quantify methane leak rates and to test potential mitigation measures. The output will be the development of best practice industry guidelines and a programme of action to implement solutions.
Importance	• The global warming potential of methane is 28 times that of carbon dioxide. Consequently, even small leaks of (bio)methane can have a material impact on the GHG saving potential. It is critically important that biomethane producers and the gas networks take action to limit these leaks. • According to the IEA[75] fugitive emissions may be characterised by structural aspects (i.e. the technologies deployed) and operational (plant management) factors. The most relevant ones include open storage or composting of the digestate; CHP engine exhaust; leaks from the digester and the pressure release valve. • Potential fugitive emissions in the gas networks may arise from leaks from process equipment (e.g. compressor stations, pressure reduction systems).
GNC involvement	• GNCs to oversee this work, including overseeing the desk-based research, co-ordinating trials at biomethane producers and dissemination of project results. • GNCs experience in leak detection to be utilised.
Other stakeholders	• BEIS, biomethane producers, HSE, industry associations (ADBA, REA).
Timeline	• 2020 +
Costs	• c. GBP5 million

ACTION 9: Raise awareness of the need to switch to low carbon heating technologies

Category	Assessment

Action description	• To raise awareness of the need to switch to low carbon heating technologies and the necessary actions that need to be taken. Information campaigns are to be tailored according to messaging needs and run on a regular basis:
	  ○ National campaigns to raise general awareness
	  ○ Targeted campaigns (region specific, end-user specific) co-ordinated with regional transitions to hydrogen

Importance	• A number of barriers exist to the deployment of low carbon heating technologies in the domestic and commercial sectors:[76]
	  ○ Lack of knowledge of hydrogen boilers and heat pumps and general low awareness of technologies, timescales and implications of change.
	  ○ Perceived issue of 'limited added benefit of switchover for consumer' in spite of widespread acceptance of environmental need
	  ○ Hydrogen seen to be a more like-for-like replacement of the current natural gas system and therefore easier to grasp than heat pump conversion, however perceptions on the safety of hydrogen need to be overcome
	  ○ Extended disconnection from gas grid during hydrogen conversion viewed as problematic
	• Similarly, barriers exist in industry.
	• It is critical that these concerns are addressed to ensure that the implementation of low carbon heating technologies is successful. Communication campaigns are seen as an effective way of achieving this aim.

[74] Fugitive emissions in the distribution network will be greatly reduced by 2032 through the scheduled completion of the Iron Mains Replacement Program.

[75] IEA Bioenergy Task 37 (2017), Methane emissions from biogas plants. Methods for measurement, results and effect on greenhouse gas balance of electricity produced. http://task37.ieabioenergy.com/files/daten-redaktion/download/Technical%20Brochures/Methane%20Emission_web_end.pdf

[76] Based on CCC analysis.

Category	Assessment
GNC involvement	• GNCs can work with other stakeholders to lead on campaign development. A key first step is to conduct GB-wide consumer research, covering all relevant sectors. Following this, the GNCs can support campaign programme development, including identifying outreach channels (e.g. tv, radio, social media, leaflets, hotlines) and designing the campaigns. • GNCs experience in coordinating end-user interventions and related communication activities to be utilised,
Other stakeholders	• National and Local Government, Local Enterprise Partnerships, industry associations (installers, suppliers), consumer groups.
Timeline	• 2020 +
Costs	• c. GBP10+ million

2. 'Medium' involvement of gas networks

ACTION 10: Implement changes to the Gas Safety (Management) Regulations (GS(M)R) and Calculation of Thermal Energy Regulations (CoTER)

Category	Assessment
Action description	• To carry out changes to the GS(M)R and CoTER regulations to enable the introduction of low and zero carbon gases into the gas grid network. Current volume-based billing methodology dictates a tight gas quality specification under CoTER which precludes the introduction of a variety of gases including hydrogen into the network.
Importance	• Enables the addition of hydrogen and other GS(M)R gases to the gas networks. • Removes the requirement to add propane to biomethane production - biomethane produced from an anaerobic digestion plant is of a lower calorific value than the gas quality specification in the current version of the regulations. The requirement to add propane and undertake accurate measurement is estimated to add costs of GBP150,000 per year for a 500 m^3 per hour capacity plant. This cost negatively impacts the business case of many potential biomethane projects. Furthermore, given that the propane source is fossil based it also increases greenhouse gas emissions of the biomethane. • Accurately or fairly bill customers for the energy they use rather than the volume of gas consumed. • Lower barriers of entry for new gas suppliers – less onerous monitoring, reporting and equipment demands will encourage increased supplies of low and zero carbon gases.
GNC involvement	• GNCs have been active in discussions about amending the GS(M)R. These include, the proposed development of an IGEM gas quality standard. • Cadent is leading a Future Billing Methodology (FBM) innovation project with the objective to enable greater volumes of low carbon and renewable gas to enter the gas networks and accurately bill end-users for their gas use. • Funds need to be allocated for RIIO-2 to continue this work with the aim of amending gas quality requirements that are 'fit for purpose' and support efforts to decarbonise the gas grid. Funds also need to be allocated for CV monitoring/metering at agreed measurement points.
Other stakeholders	• BEIS, OFGEM, IGEM, biomethane producers, HSE, industry associations (ADBA, REA), gas suppliers and shippers.
Timeline	• Complete by end 2020.
Costs	• c. GBP5 million

ACTION 11: Large-scale demonstration of hybrid heat systems

Category	Assessment
Action description	• To carry out large scale trials of hybrid heating systems and networks following up on current smaller scale demonstrations.
Importance	• Hybrid heat systems are seen as an integral component of our 'Balanced Scenario'. • Wales & West Utilities' Freedom Project has successfully demonstrated principles of hybrid heating systems. • A next step is to scale-up these demonstrations (to over 1,000 homes), in order to improve the evidence base and prepare the market for mass roll-out. • Need to demonstrate resilience and control of systems and fully understand supply network needs for large scale deployment of heat pumps and back up heating boilers. • Need to fully understand funding and support requirements to ensure high take up by consumers.
GNC involvement	• GNCs to play an important role in supporting large-scale demonstrations, working alongside other stakeholders utilising their experience in coordinating end-user interventions. • Demonstrations need to be completed well-before 2025 so that any lessons learned are incorporated in the full scale roll out.
Other stakeholders	• Equipment suppliers and installers, BEIS, OFGEM.
Timeline	• Complete by end 2023/4.
Costs	• c. GBP10+ million

ACTION 12: Developing the UK skills and labour capacity

Category	Assessment
Action description	• The introduction of new technologies and the transition to low carbon heating is seen as a key challenge for existing engineers. Extensive re-training will be required and the energy and building sectors need to attract suitable candidates into engineering, heating and plumbing to cope with future demands.
Importance	• The UK currently has around 130,000 Gas Safe Engineers, of which over 80% work on domestic heating and hot water systems there are also currently 250,000 plumbers, but only around 2,000 MCS certified heat pump installers.[77] • The workforce is ageing and fewer new entrants due to a lack of interest in the energy sector as a career prospect among young people.[78] • Industry structure is seen as an issue, since most plumbers and gas engineers are self-employed trades people. • The Gas Safe Register currently has no remit outside of piped gas (as per GSIUR 1998), hence engineers are unable to work on heat pumps or hydrogen.
GNC involvement	• Apprenticeship schemes need to be established and supported financially by Government. • Training programmes will need to be developed and offered to "re-skill" the existing workforce on new technologies and a 'Gas Safe' hydrogen changeover accreditation is also needed. • Raising awareness of the opportunities within the energy sector (including options outside of universities) is also important to attract new entrants to the sector (e.g. at schools, job fairs, press, social media sites). • GNCs can actively support all these actions in-conjunction with other initiatives in this area (e.g. the Hydrogen Transportation Group).
Other stakeholders	• BEIS, Industry Associations, Education Sector.
Timeline	• 2020-2030/35
Costs	• c. GBP50 million/year

[77] https://www.microgenerationcertification.org/about-us/statistics/

[78] Siemens (2014), Skills In Energy: Bridging The Gap. https://www.siemens.co.uk/pool/insights/skills-in-energy-bridging-the-gap.pdf

ACTION 13: Testing and certification of dual fuel appliances/equipment

Category	Assessment
Action description	• Facilitate the testing and certification processes for the new generation of appliances designed to operate on a range of hydrogen/methane gas blends
Importance	• Early development and deployment of dual gaseous fuel appliances can future proof end-users against the costs of a potential conversion of the network region from natural gas to hydrogen. • Manufacturers indicate a target availability of such appliances and equipment by 2026. • Dual fuel appliances will require testing and certification well in advance of their being made commercially available. • Dual fuel appliances will automatically replace 'end-of-life' conventional gas fired appliances/equipment.
GNC involvement	• GNCs can facilitate this process by providing access to gas networks and supplying blended gas, working alongside other stakeholders and existing programs (e.g. Hy4Heat – WP3). Testing and certification should be completed as soon as possible.
Other stakeholders	• Equipment suppliers, Testing and Certification Houses, British and CE Standards
Timeline	• 2020-2026
Costs	• c. GBP3 million (in addition to ongoing spend)

ACTION 14: Evaluating opportunities for anaerobic digestion based biomethane deployment in off-grid buildings

Category	Assessment
Action description	• Conduct real-life trials in the use of biomethane in off gas grid situations including as a support fuel for hybrid heat supply.

Importance	• The trials will help to identify the most cost and carbon saving optimum solution(s) and next steps for deploying anaerobic digestion based biomethane in off-grid buildings.
	• The CCC sees an important role for biomethane in off-gas buildings especially serving peak demand in-conjunction with hybrid heat systems.[79]
	• Trials can be used to assess:
	  ○ Aggregation options (e.g. centralised upgrading plant supplied by small-scale anaerobic digestion plants vs. decentralised)
	  ○ Logistics (e.g. compressed gas vs. liquified gas)
	  ○ End-use application (e.g. gas boiler vs. hybrid system)
	  ○ Energy efficiency measures

GNC involvement	• GNCs can facilitate off grid biomethane usage assessment of supply chain development and real-life trials by working as overall project coordinator for biomethane producers and existing LPG suppliers (who have storage, logistics, billing systems and importantly potential customers).
Other stakeholders	• Biomethane producers and potential suppliers.
Timeline	• 2020-2023
Costs	• c. GBP5 million

[79] Committee on Climate Change (2019), Net Zero – Technical Report. https://www.theccc.org.uk/publication/net-zero-technical-report/

ACTION 15: Evaluating opportunities for Biomethane Power-to-Gas

Category	Assessment
Action description	• Trials to be conducted to assess techno-economic performance and opportunities for biomethane power to gas scale-up and cost reduction.
Importance	• Biomethane produced via Power-to-Gas provides an option for biomethane producers to maximise production through use of currently (largely vented) CO_2. • This is a particular opportunity for waste-based anaerobic digestion plants as the CO_2 use markets are more limited.
GNC involvement	• GNCs to provide project support (as Cadent have supported GoGreenGas Bio-SNG project).
Other stakeholders	• (Waste based) biomethane producers, Power-to-Gas technology providers.
Timeline	• 2020-2025
Costs	• c. GBP3 million

3. 'Low' involvement of gas networks

Finally, there are a number of actions that are fundamental to the delivery of our Pathway. We have detailed three specific actions below that are considered most critical. These all relate to national policy development.

The gas networks can still play an important role in supporting these actions. For example, through regular engagement with policy makers, provision of data or information and in responding to government consultations.

1. Energy efficiency policy framework and funding mechanism (domestic / non-domestic)

The reduction of energy demand through the widespread adoption of energy efficiency measures is an important component of our Pathway in both the domestic and non-domestic sectors. However, the installation of insulation and other energy efficiency measures, including hybrid heat systems, will require significant upfront expenditure. This may act as a deterrent to end-users to fully participate in the energy system transition.

Using learnings from previous schemes such as Warm Front and the Energy Company Obligation (ECO) scheme, a policy framework should be established to promote the rapid deployment of energy efficiency measures and furthermore address how expenditures are to be financed to enable full end-user participation. In the buildings sector the framework needs to be designed to reflect different stakeholder groups – owner-occupied, social- and private-rented homes and non-residential buildings. Given the scale of the low carbon transition it is imperative that this action is progressed without delay, with sufficient advanced notice to enable industry to scale-up supply-chains and labour capacity.

2. Cost distribution methodology for low carbon transition (domestic / non-domestic)

End-users in different regions of GB will continue to get the same choice of energy supply as they do today, however, the source of the energy they receive, in particular gas consumers will change. Some will have access to biomethane and electricity, others to hydrogen and electricity, the prices of these energy carriers will be different to each other. As a consequence, end-users of gas across GB will have different energy costs.

We contend that the prices of new alternative energy, sources such as low carbon and renewable gases, should not be artificially managed for the majority of domestic end-users in much the same way as prices of heating oil, propane, biomass fuels etc. are currently left to market forces to dictate. Whilst the mix of fuels in GB's energy supply network will change, regional differences in access to fuels and their associated supply costs is not a new phenomenon.

If the overall cost of energy increases for some domestic customers due to the changing energy mix, then Government will need to explore options to increase support for those in fuel poverty.

Further, Government should carefully assess the implications of potential increases in fuel costs for industry to avoid any competitive distortions, internationally and, albeit less likely, across GB. In the event that the changing fuel mix leads to a disproportionately higher cost for certain sectors subject to international competition, Government may need to introduce assistance measures. We would recommend that a similar (albeit not identical) approach be applied in terms of assessment and assistance to that currently used to assess the impact of carbon pricing and associated assistance for some industry such as carbon pricing and carbon price support tax exemptions, temporary corporation tax reductions for new equipment purchases, or a system of targeted support for business with significant competitive challenges and high energy use.

3. CCUS implementation

The successful implementation of CCUS is fundamental to achieving net-zero emissions in our Pathway. A number of aspects need to be considered for successful implementation:

(a) **Policy framework:** A stable policy framework needs to be established to incentivise the application of CCUS in GB. The framework should cover, amongst others, monetising negative emissions (relevant to Bio-SNG and biomass power with CCUS), the development of CCUS transportation and storage infra-structure and the responsibility for the long-term carbon storage risk. The gas sector needs to be very proactive in its engagement with the CCUS Council and its response to governments CCUS deployment pathway - action plan, actively participating in discussions particularly in relation to pre-delivery actions.

(b) **Funding mechanisms:** In the short-term, funding needs to be made available to support CCUS project development and to further de-risk the technology. In parallel, funding mechanisms need to be set-up to provide confidence to project developers on how expenditure for commercial scale CCUS projects can be recovered. An overarching aim of any funding must be to reduce CCUS costs. To achieve these objectives, long-term commercially viable business models for the large-scale application of CCUS are needed.

In July 2019, BEIS issued a consultation (closing date 16/09/2019) looking at CCUS business models for industry, power, and carbon dioxide transport and storage and importantly suitable business models to support hydrogen production with CCUS. Viable outcomes from the consultation should be enacted at the earliest opportunity to sustain momentum gained by Government's recent CCUS Action Plan and demonstration project funding allocations.

(The Government's Clean Growth Strategy and CCUS Action Plan has set out an initial CCUS framework and allocated GBP44 million for CCUS demonstration projects. From this, funding has recently been approved for several projects including a project offshore from Aberdeen and another in Teesside. A Tata Chemicals carbon utilisation project in Cheshire will also receive Government funding.)

4. Potential market support areas

There are other potential areas where targeted support should be explored:

(a) **Market support for Biomethane and Bio-SNG production:** Our Balanced Scenario highlights the need for significant scale up of biomethane and Bio-SNG production from present levels to 2050. We note the decision by the UK government to extend Renewable Heat Incentive payments for anaerobic digestion based biomethane until 31 January 2021, however consideration should be given to continue some form of post RHI support to encourage more and larger plants to provide sufficient gas for injection to grid but also importantly, for off gas grid use in hybrid heating systems.

The production of Bio-SNG through the gasification of biomass and waste (RDF/SRF) also forms an important part of our Balanced Scenario supplying 121 TWh by 2050. Such plants will be relatively costly to build in the short-term, but will importantly enable negative emissions to be realised which are a critical component of our Balanced Scenario. A commercial demonstration plant is currently under latter stage construction in Swindon which will be able to provide a good commercial insight for future plant development and provide guidance into the best means of support, should support be needed.

(b) **Market support for Green Hydrogen Production:** We forecast 117 TWh of hydrogen by 2050 produced through electrolysing water using curtailed and dedicated electricity from wind and solar farms. The first supply of renewable hydrogen should commence by 2026, however it is important that support is provided to stimulate electrolyser developments to increase capacity and raise efficiencies which will lead to reductions in costs making hydrogen increasingly competitive with other energy forms from 2030 onwards.

(c) **Post CAP framework to support UK biomass/energy crops (for Anaerobic digestion and Bio-SNG):** The development of UK biomass sources, in particular energy crops (such as short rotation coppice willow and miscanthus) and forestry, is necessary in order for the Bio-SNG potential to be fully realised by 2050. The reform of the CAP framework provides an opportunity to support this development. For example, through the provision of establishment grants, or support to develop supply chain infra-structure.

APPENDIX H. OVERVIEW OF SELECTED LITERATURE

In this appendix, we provide a concise high-level overview of a selection of comparative studies on the topic of the low carbon energy transition to 2050. These include:

- Element Energy / E4tech (March 2018). Cost analysis of future heat infrastructure options
- Imperial College London (November 2018). Analysis of Alternative UK Heat Decarbonisation Pathway
- Committee on Climate Change (May 2019). Cost analysis of future heat infrastructure option
- National Grid (July 2019). Future Energy Scenarios

For each study, we aim to summarise key outputs for a selection of aspects. These include, (scenario) costs, low carbon and renewable gas supply, electricity generation (capacity and supply), as well as energy demand by sector (where available). Additional aspects, such as assumptions on biomass feedstock potential are also included. This overview, however, is not intended to serve as a critique of the studies.

It is evident from this overview that the study outputs differ widely. This stems from differences in the modelling approaches and assumptions applied by the studies, and ultimately that each study has a specific research aim. This makes a meaningful comparison to our study fundamentally challenging.

1. Element Energy / E4tech (March 2018). Cost analysis of future heat infrastructure options

Element Energy and E4tech were commissioned by the National Infrastructure Commission (NIC) to undertake an analysis of the cost of decarbonising the UK's heat infrastructure, specifically space heating and hot water. This study aims to assess the likely costs of decarbonising UK heat using different pathways, whilst highlighting the impact of uncertainties and practical barriers on the feasibility of implementing the different pathways.

The study suggests that space heating and hot water provision currently accounts for approximately 100 Mt CO_2 per yr, a contribution that is likely to be required to fall below 10 Mt CO_2 per yr by 2050 to be compatible with a UK economy-wide 2050 carbon emissions target of 80%.

All heat decarbonisation options studied are significantly more costly than the Status Quo under all scenarios (see Figure 36 Comparison of main pathway options (Figure 1-1 in study)). The cumulative additional cost to 2050 versus Status Quo (discounted at 3.5%) is in the range GBP120-300 billion under the Central cost assumptions. Under the Best case assumptions, the corresponding range is GBP100-200 billion and in the Worst case assumptions GBP150-450 billion. The average annual cost of heating per household is found to be GBP100-300 higher in 2050 than in the Status Quo.

Re-purposing the gas grid to deliver low carbon hydrogen is seen as the lowest cost option under most scenarios studied. However, the report emphasises the uncertainty associated with this pathway compared to the others (e.g. reliance on CCS technology deployment). CCS is viewed as a pre-requisite for the hydrogen heating pathway, in order to support the application of steam methane reformation (SMR) for hydrogen production, as it is highly unlikely that electrolysis could provide sufficient hydrogen for a national rollout of hydrogen heating at reasonable cost.

All-electric heat pump heating is found to be the most costly of the main pathway options under most scenarios. The largest share of the cumulative discounted system cost (exceeding GBP200 billion) is associated with investment at the building level, in the heat pump unit itself and the accompanying

energy efficiency and building renovation work required. Electricity network upgrade costs are estimated at around GBP20 billion.

	Electrification (heat pumps)	Electrification (direct electric)	Hybrid gas-electric	Hydrogen grid
Suitable building stock segments	• On- and off-gas • Suitable for efficient buildings – maximum deployment requires widespread retrofit	• On- and off-gas • Suitable for all building efficiency levels	• On-gas only • Suitable for all building efficiency levels	• On-gas only • Suitable for all building efficiency levels
Achievable level of heat decarbonisation at maximum deployment	**5-10 $MtCO_2$** (Limited by grid CO_2)	**10-15 $MtCO_2$** (Limited by grid CO_2)	No green gas: **20-25 $MtCO_2$** With green gas: **15-20 $MtCO_2$** (Limited to on-gas)	**20-25 $MtCO_2$** (Limited to on-gas and 90% CCS capture)
Cumulative additional cost vs Status Quo to 2050 at maximum deployment (discounted at 3.5%)	Central case: **£270 bn** Range: **£210-450 bn**	Central case: **£190 bn** Range: **£180-250 bn**	No green gas: Central case: **£180 bn** Range: **£120-320 bn** With green gas (40 TWh): Central case: **£210 bn** Range: **£150-350 bn**	Central case: **£130 bn** Range: **£110-160 bn**
Annualised costs in 2050	Capital costs: **£21 bn** Operating and fuel costs: **£19 bn**	Capital costs: **£5 bn** Operating and fuel costs: **£33 bn**	Capital costs: **£15 bn** Operating and fuel costs: **£25 bn**	Capital costs: **£8 bn** Operating and fuel costs: **£28 bn**
Key uncertainties	Heat pump unit cost, requirement for energy efficiency retrofit, grid reinforcement cost	Electricity fuel cost, grid reinforcement cost, heating system unit cost	Heat pump unit cost, actual emissions reduction strongly dependent on consumer behaviour, potential contribution of green gas	Safety case, in-building retrofit cost, consumer acceptability, readiness and cost of CCS
Deployment timescales	• Ready to deploy • Consistent with long-term CO_2 budget	• Ready to deploy • Consistent with long-term CO_2 budget	• Ready to deploy • Only consistent with long-term if near-fully green gas (also need off-gas solution)	• Unlikely before 2030s • Consistent with long-term CO_2 budget (also need off-gas solution)

Figure 36 Comparison of main pathway options (Figure 1-1 in study)

Hybrid heat systems[80] are more cost-effective than full electrification using heat pumps in the majority of scenarios (excluding Hybrid heat systems in combination with biomethane grid injection). This is due to a reduction in costs incurred both at the building level (significant building renovation costs associated with pure electric heat pumps can be avoided) and at the electricity network/generation level (since the peak heat demand can be met through the gas network).

The study sees a role for the production of hydrogen via biomass gasification with CCS as a potential means of achieving negative emissions in the heat sector. This analysis finds that the production of 47 TWh per yr of biohydrogen, combined with CCS, could lead to an emissions reduction of 24 Mt CO_2 per yr by 2050, and potentially net negative emissions from the heat sector overall. This study views this as an upper limit, however, as various other sectors are likely to compete for the underlying feedstocks required to produce the biohydrogen.

The study also assessed a series of 'Mixed' scenarios:

1. **Hydrogen led + biomass off-gas:** UK gas grid is repurposed to carry low carbon hydrogen, and low cost biomass is installed in off-gas buildings, displacing oil and electric based heating.

2. **Hybrid gas-electric + grid injection + direct electric heating off-gas:** Hybrid heat systems are installed in all on-gas buildings, and low carbon biomethane is injected into the gas grid. In order to fulfil this grid injection demand, almost all low cost available bioenergy feedstocks are required, so electric heating is used as an off-gas solution.

3. **Heat pumps + bioenergy in hard-to-insulate buildings:** All Low and Medium cost energy efficiency measures are applied across the stock, and heat pumps are applied in all buildings in the high efficiency band. The remaining buildings that are insufficiently insulated to be suitable for a heat pump use a biomass solution.

[80] Note that the Element Energy study uses the term "Hybrid heat pumps". We have instead used the term "Hybrid heat systems" for consistency with our study.

4. **Hydrogen led + direct electric heating off-gas:** UK gas grid is repurposed to carry low carbon hydrogen with direct electric heating in off-gas buildings.

5. **Hydrogen led + biomass gasification with CCS + direct electric heating off-gas:** Hydrogen is produced by a mix of SMR and biomass gasification (both implemented in conjunction with CCS). Direct electric heating systems are applied to all off-gas buildings.

The cumulative additional system cost to 2050 of each Mixed scenario relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown in Figure 37. The cumulative discounted cost of the scenarios to 2050 versus the Status Quo ranges from GBP141 bn for the "Hydrogen led + biomass off-gas" scenario, to GBP237 bn for the "Hybrids + grid injection + direct electric off-gas" scenario.

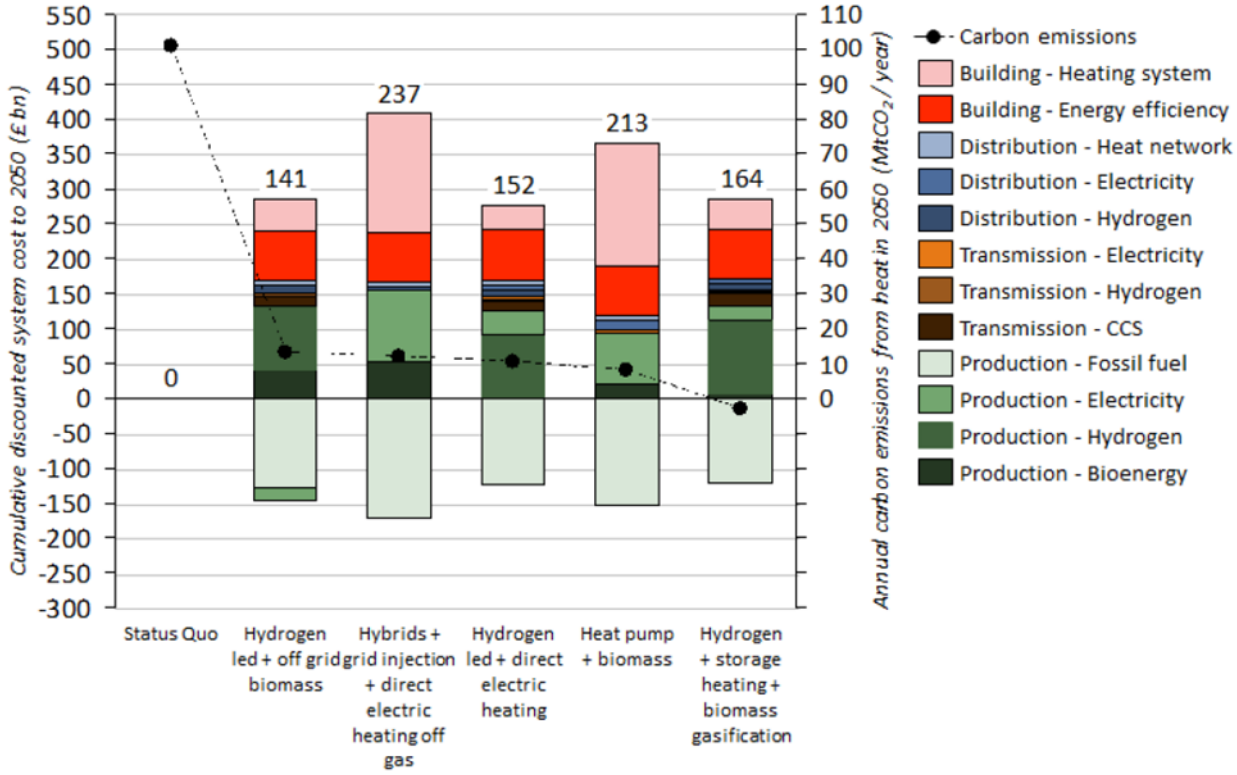


Figure 37 Uncertainty in cumulative additional system cost to 2050 – Mixed scenarios (Figure 1-6 in study)

2. Imperial College London (November 2018). Analysis of Alternative UK Heat Decarbonisation Pathway

This study was undertaken for the CCC using Imperial's Integrated Whole-Energy System (IWES) model to assesses the technical and cost performance of 9 alternative decarbonisation pathways for low carbon heating in 2050. 3 pathways (Hybrid, Electric and Hydrogen) were modelled, each with 3 decarbonisation scenarios (30 Mt, 10 Mt and 0 Mt residual emissions).

- **Hybrid:** Based on the application of combining the use of gas and electric heating systems, (i.e. hybrid heating system). The gas heating system in the Hybrid system uses natural gas or carbon-neutral gas such as biogas or hydrogen to reduce emissions from gas.
- **Electric:** Heat demand is met by the optimal deployment of end-use electric heating appliances including heat pumps and resistive heating.
- **Hydrogen:** Based on the application of end-use hydrogen boilers at consumer premises to decarbonise heat demand. It is assumed that consumers that do not have access to gas would use electric heating.

Similar to our study, the Hybrid pathway is determined to be the lowest cost, followed by the Electric pathway (see Table 4 below). The difference between these pathways is only GBP4 billion/year for the 0 Mt scenario. The Hydrogen pathway is determined to be the highest cost, in particular for the 0 Mt scenario. The modelling approach with respect to the cost components included is different to our study so a direct comparison of the results is difficult. For example, energy efficiency costs are excluded in the Imperial study as it is assumed that energy efficiency measures would need to be implemented on a consistent basis in all pathways. In contrast, these costs are included in our study, but differ between the scenarios. The Imperial study includes cost of hydrogen storage, which was not considered in our study.

Table 4 Cost performance of different decarbonisation pathways (units: GBP bn per year) (Table E.1 in the study)

Pathways	30 Mt	10 Mt	0 Mt
Hybrid	81.6	84.8	88.0
Electric	78.8	89.5	92.2
Hydrogen	89.6	90.2	121.7

Table 5 below provides an overview of the respective renewable gas shares in each of the pathways. Biomethane supply is significantly lower in the Imperial study, at only 21 TWh in all pathways, and exclusively produced via anaerobic digestion. A key difference with our study is that there is no Bio-SNG supply; it is assumed that biomass is instead used to produce Biohydrogen via thermal gasification. No hydrogen imports are assumed, which is consistent with our study.

Table 5 Hydrogen and Biomethane gas volumes across the pathways (units: TWh)

	Hydrogen Green	Hydrogen Blue	Hydrogen - Biomass	Biomethane	Total
Hybrid	44	0	93	21	158
Electric	168	0	93	21	282
Hydrogen	406	168	93	21	688

The Imperial study applies a more conservative biomass supply of 135 TWh, based on the CCC 2011 Bioenergy Review. No biomass imports are considered. This compares to 342 TWh in our study, 155 TWh of which relates to biomass imports. Our study assumes that biomass is used in multiple applications, including Bio-SNG production, heat and power generation and aviation fuel production. Importantly, 'negative emissions' via bioenergy with CCS are not accounted for in the Imperial study. This results in a zero take-up of blue hydrogen in the Hybrid and Electric pathways, and a relatively lower share of blue hydrogen in the Hydrogen pathway (since negative emissions are not available to offset the residual emissions of blue hydrogen production).

Electricity generation ranges from 767 TWh in the Electric pathway to 946 TWh in the Hydrogen pathway, with 787 TWh in the Hybrid pathway (compared to 847 TWh in our study). Nuclear plays a dominant role in all pathways providing around 44% of total supply (installed capacity is capped at 45 GW as in our study).

Finally, the report assumes that significant short-term energy system flexibility is provided by demand shifting via pre-heating and thermal storage in homes. 50% of the potential demand flexibility is assumed to be available.

3. Committee on Climate Change (May 2019). Cost analysis of future heat infrastructure options[81]

This report accompanies the 'Net Zero' advice report which is the Committee's recommendation to the UK Government and Devolved Administrations on the date for a net zero emissions economy wide target in the UK and revised long-term targets in Scotland and Wales. A number of technical reports underpin the analysis in this report. The Net Zero report considers three scenarios:

- **Core Options:** Low-cost low-regret options that make sense under most strategies to meet the current 80% 2050 target. They also broadly reflect the Government's current level of ambition (but not necessarily policy commitment).
- **Further Ambition:** Options are more challenging and on current estimates are generally more expensive than the Core options.
- **Speculative Options:** Currently have very low levels of technology readiness, very high costs, or significant barriers to public acceptability. It is very unlikely they would all become available.

The Further Ambition scenario realises 96% GHG emission savings below 1990 levels, resulting in residual emissions of 34 Mt CO_2e. It is envisaged that the UK can credibly achieve net zero emissions in 2050 by implementing a range of Speculative options. The details provided in this overview focus on this scenario, unless otherwise stated.

Hydrogen production and use in the Further Ambition Scenario is illustrated in **Figure 38** below. Total production is 270 TWh, and primarily based on blue hydrogen (225 TWh). This production assumes a build rate of between 2 and 3 GW per year. The greatest hydrogen demand is in industry (120 TWh, 44%), followed by shipping (70 TWh, 26%) and in buildings (53 TWh, 20%). No hydrogen imports are assumed. Biohydrogen production via thermal gasification is viewed as a 'Speculative Option'.

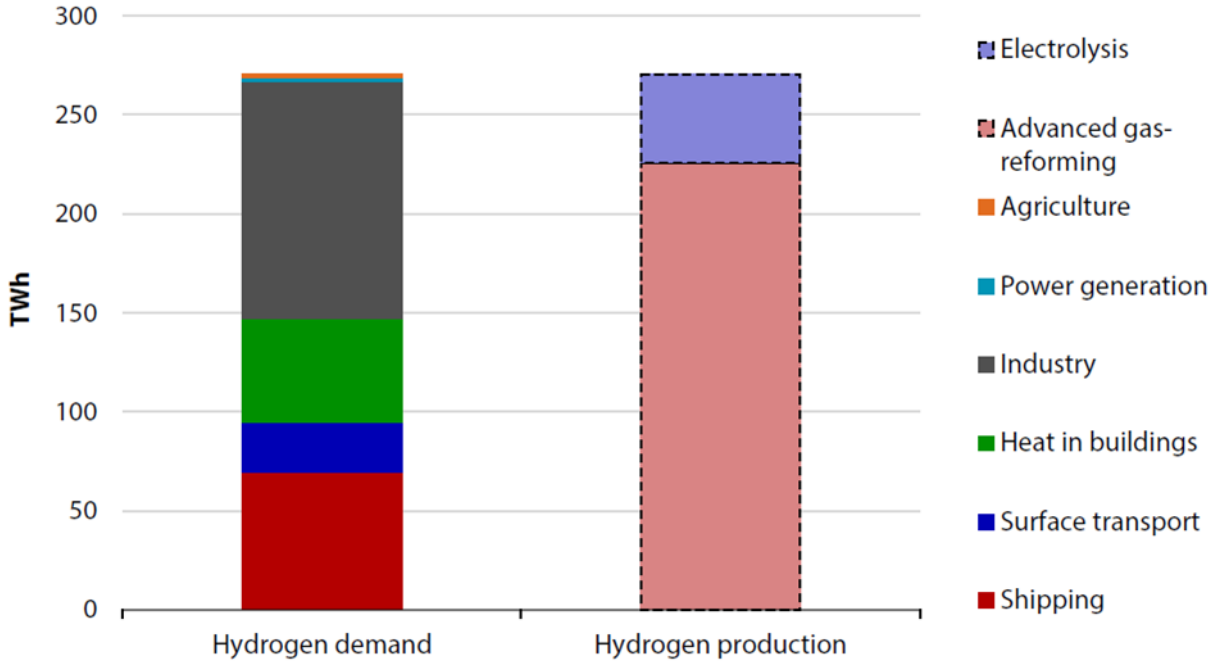


Figure 38 Use and production of hydrogen in the Further Ambition Scenario in 2050 (Figure 2.8 in the study)

[81] https://www.theccc.org.uk/publication/net-zero-technical-report/

Gas distribution networks are assumed used to transport hydrogen to buildings, power generation and industrial facilities and vehicle refuelling stations. The scenario assumes that some new hydrogen transmission infrastructure is built. However, additional hydrogen storage (e.g. salt caverns) is not included due to the limited role for hydrogen in buildings.

Biomethane is seen to play a role in the short-term (to 2030) with 20 TWh injected into the grid, but not out to 2050. Biomethane use in 2050 is restricted to serving peak demand in off-gas buildings with hybrid heat systems.

The indicative electricity generation is 645 TWh in 2050 (see Figure 39), producing 594 TWh. Renewables dominate, with an expected share of at least 59% of generation in 2050. 23% of generation comes from gas fired plants fitted with CCUS. Nuclear is expected to provide a minimum contribution of 26 TWh (4% of generation, possibly increasing to 11%). Biomass with CCUS provides 6%, but importantly realises 34 Mt CO_2e negative emissions. Finally, a significant amount of stand-by capacity (40-120 GW), mostly provided by open-cycle gas turbines or other flexible gas plant, fuelled by hydrogen and/or ammonia provides less than 1% of electricity generation. Peak demand is expected to be 150 GW in 2050.

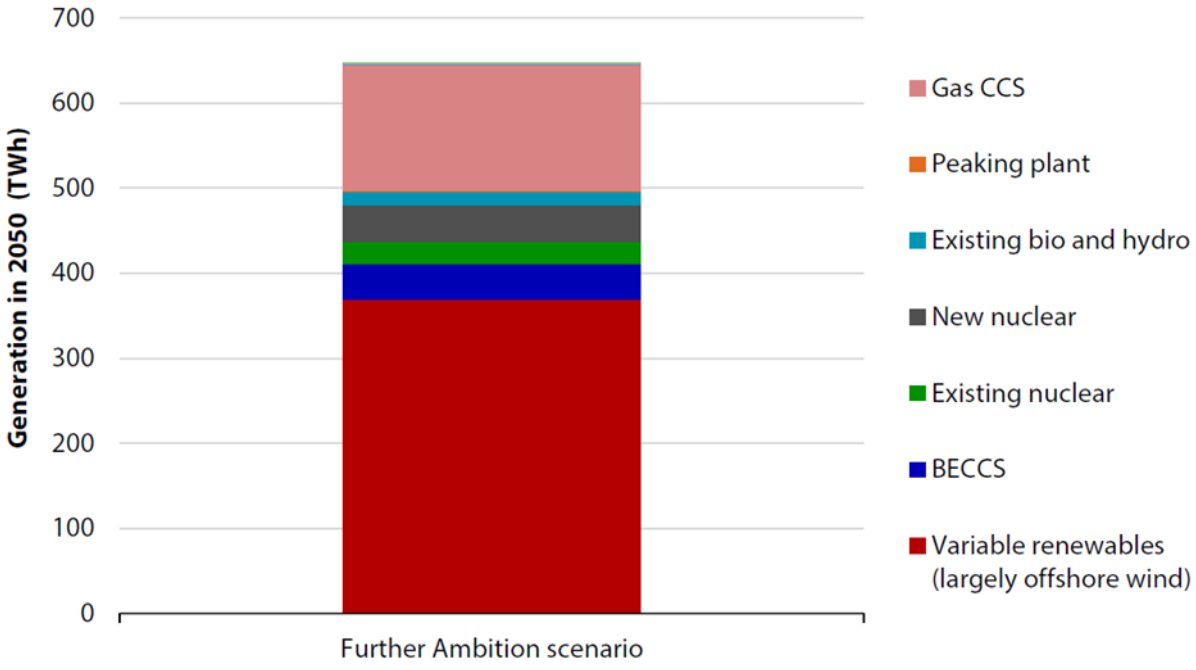


Figure 39 "Illustrative generation mix" for a low-carbon power system in 2050

In buildings, it is assumed that no new homes are connected to the gas grid post-2025 and from 2030, no new gas cooking appliances are installed. Heat pumps are dominant heating system in homes by 2050, with 19 million units deployed. 75% are all-electric and 25% hybrid heating systems running on hydrogen for homes that are on the gas grid and Bio-LPG for homes off the gas grid. The technology mix in the Further Ambition scenario also includes around 460,000 homes with electric storage heating. The costliest 10% of homes to implement low carbon heating solutions remain using fossil fuel heating in 2050, resulting in residual emissions of up to 4 Mt CO_2e in the Further Ambition scenario.

The Further Ambition Scenario forecasts near zero emissions from the road transport sector by 2050, mainly achieved through electrification (around 76 TWh additional compared to 2017 levels). HGVs are expected to transition to zero emission options including hydrogen and electrification throughout the 2030s. Smaller rigid HGVs will likely electrify, but there are multiple options foreseen for larger rigid HGVs and articulated HGVs, including hydrogen. Around 25 TWh of hydrogen is forecast to be

used in road transport by 2050, including in HGVs, buses and trains (0.3 TWh). No role for biofuels is foreseen in road transport by 2050.

Emissions in shipping are expected to reduce to near-zero through more widespread use of alternative fuels. Ammonia represents nearly all shipping fuel demand by 2050, with a more limited role foreseen for electrification.

Residual emissions in aviation of 30 Mt CO_2e remain by 2050 in the Further Ambition Scenario. Fuel efficiency improvements, and a limited uptake of sustainable biofuels with CCUS (10% of demand) are the main decarbonisation options to 2050. This scenario also expects hybrid-electric planes to enter the fleet in the 2040s, but these represent less than 10% of total kilometres flown in 2050. Synthetic fuels made from electrolytic hydrogen and CO_2 captured from the air via Direct Air Capture (DAC) are considered to be 'Speculative Options', and not included in this scenario. These fuels are included in our study.

The Further Ambition Scenario reduces emissions in industry to 10 Mt CO2e by 2050 through a range of options, including hydrogen, electrification of heat and biomass with CCUS, as well as energy and resource efficiency. Hydrogen is expected to play the main role, with 120 TWh deployed by 2050. Our study also sees significant deployment of hydrogen (59 TWh) in industry by 2050, alongside the extensive electrification of heat (78 TWh).

The total available harvested biomass resource is assumed to be almost 200 TWh in 2050 across all scenarios, of which 112 TWh is used for biomass power generation combined with CCUS. The biomass potential estimate is based on the average of the CCC's 'Poor global governance; Low UK supply' and 'Global governance and innovation' scenarios from its report on Biomass in a low-carbon economy (Scenarios 1 and 4).

4. National Grid (July 2019). Future Energy Scenarios[82]

FES 2019 uses the same scenario framework introduced in 2018[83], but also includes a sensitivity analysis of how net zero carbon emissions could be achieved by 2050. The net zero sensitivity uses the "Two Degrees" scenario as the starting point for this analysis, as this scenario has the highest deployment of CCUS. Specific aspects of the "Community Renewables" scenario were also included in order to reach net zero emissions.

FES defines net zero as a 96% reduction in GHG emissions compared to 1990 levels across all sectors (including international aviation and shipping). Emissions in industry (10 Mt CO_2e), hydrogen production (3 Mt CO_2e) and other sectors (59 Mt CO_2e) are partially offset by negative emissions from BECCS (-37 Mt CO_2e). This results in residual GHG emissions of 35 Mt CO_2e) in 2050. It is assumed that, as yet commercially unproven technologies would develop to enable the reduction or removal of these remaining residual emissions, potentially alongside widespread behaviour change.

Hydrogen production is forecast to be 324 TWh in 2050. The split between blue and green hydrogen is not stated, however it is indicated that the majority of hydrogen production would be via methane reforming. Hydrogen production requires 354 TWh of natural gas for blue hydrogen production and 68 TWh for electricity for electrolysis. FES envisages a very limited role for biogas/biomethane. 25 TWh of biogas is used in industry in CHP plants and very limited amounts are used as BioLPG for heating in off-grid homes.

Electricity generation is 491 TWh per year by 2050, based on 263 GW generation capacity (see Figure 40). Renewables are dominant with 151 GW capacity (57% share of the total). Natural gas with CCUS is envisaged to be deployed at reasonable scale in 2050 (43 GW, 16%), with smaller contributions from nuclear (19 GW, 7%) and Biomass with CCUS (7 GW, 3%). Biomass with CCUS plays an important role in the Net Zero sensitivity providing 37 Mt CO_2 negative emissions annually by 2050[84]. Interconnector capacity is 20.1 GW. Peak demand capacity is 115 GW, which compares to 116 GW in our study.

[82] http://fes.nationalgrid.com/fes-document/

[83] **Two Degrees and Community Renewables** meet the UK's 2050 80% GHG emission reduction target, but feature different levels of decentralisation. **Steady Progression and Consumer Evolution** do not meet the 2050 target.

[84] 43 TWh of electricity from BECCS are produced in 2050, using 117 TWh of biomass.

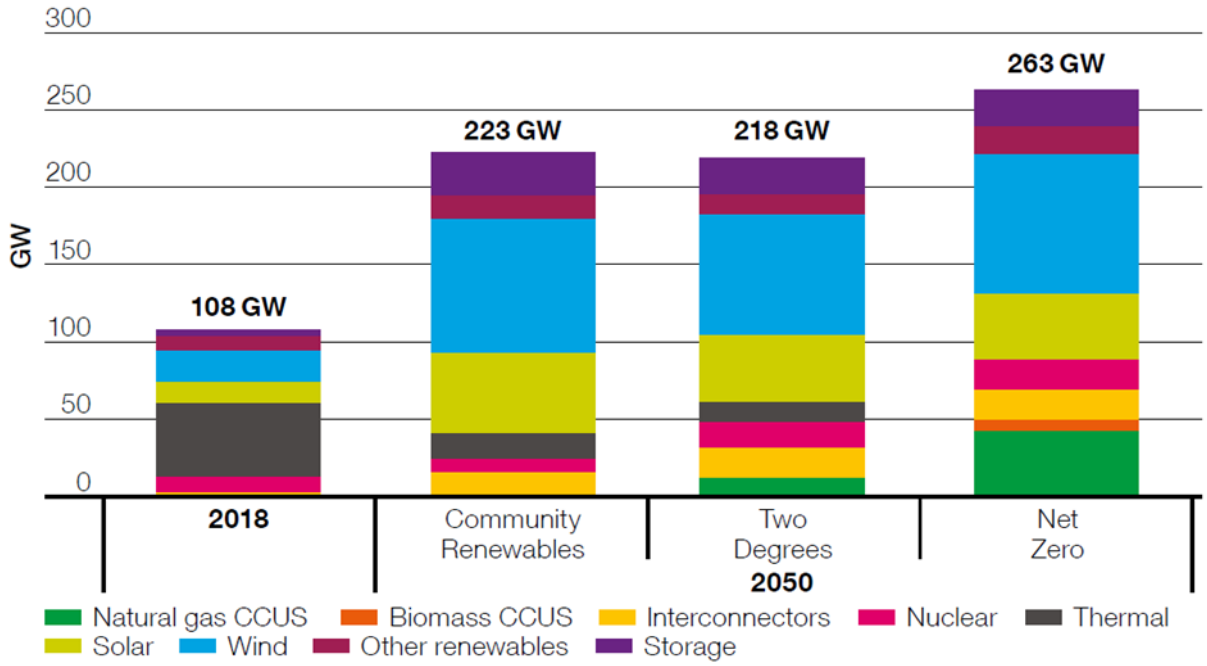


Figure 40 Installed electricity generation capacity: Community Renewables, Two Degrees and Net Zero in 2050
(Figure 6.3 in the study)

In the buildings sector, hydrogen gas boilers are the dominant heating type with almost 14 million units installed by 2050. FES forecasts that 12.5 million heat pumps are installed by 2050, of which 8.6 million are all-electric heat pumps. Reduction in energy demand is further supported through the implementation of thermal storage measures in 25% of homes.

The FES Net Zero sensitivity forecasts significant growth in electric vehicles in the road transport sector, similar to the Two Degrees and Community Renewables scenarios. A difference is in heavy goods vehicles, which all shift to electric or hydrogen powered engines, in contrast to these scenarios where some vehicles are still using natural gas in 2050. Biofuels are used in aviation and shipping, however the volumes are not stated.

The industrial sector sees an increase in the use of hydrogen and electricity as well, alongside gas paired with CCUS, plus some use of bioenergy, such as biogas in CHP plants.