Accelerating Progress towards 2030s Carbon Budgets

Final report

February 2025

Practical gas network measures could help close a quarter of the gap to achieving carbon budgets in buildings and industry

- According to the CCC, low carbon investment in **buildings and industry is off-track**. We estimate the gap in these sectors between required abatement* and business as usual emissions** is 47 MtCO2e/year in 2035 for Great Britain.
- We have identified **practical, cost effective and realisable** ways in which the gas networks could help bring decarbonisation of these sectors back on track, reducing the gap by at least 11 MtCO2e/year in 2035 (i.e. by 23%), provided policymakers and regulators put in the **right supportive actions**
- These measures would have **wider energy system benefits**, including delivering an additional 2 MtCO2e/year in 2035 by supporting decarbonisation of dispatchable power and supporting the flexibility provided by remaining gas-fired generation.

Actions
Clear strategic vision
Supportive business models for industry and households
Financing the required network expenditure

Measures	Impact (MtCO2e saved in 2035)
Step change in **biomethane** injections: 60 TWh by 2040	4.5
Blending hydrogen in natural gas networks	0.8
Repurposing part of the gas network for **100% hydrogen**	1.8 (+2MtCO2e for power)
Reducing **gas networks' own emissions**	0.5
940,000 additional hybrid heat pumps by 2035	2.0
1 million additional district heating connections by 2030	1.1

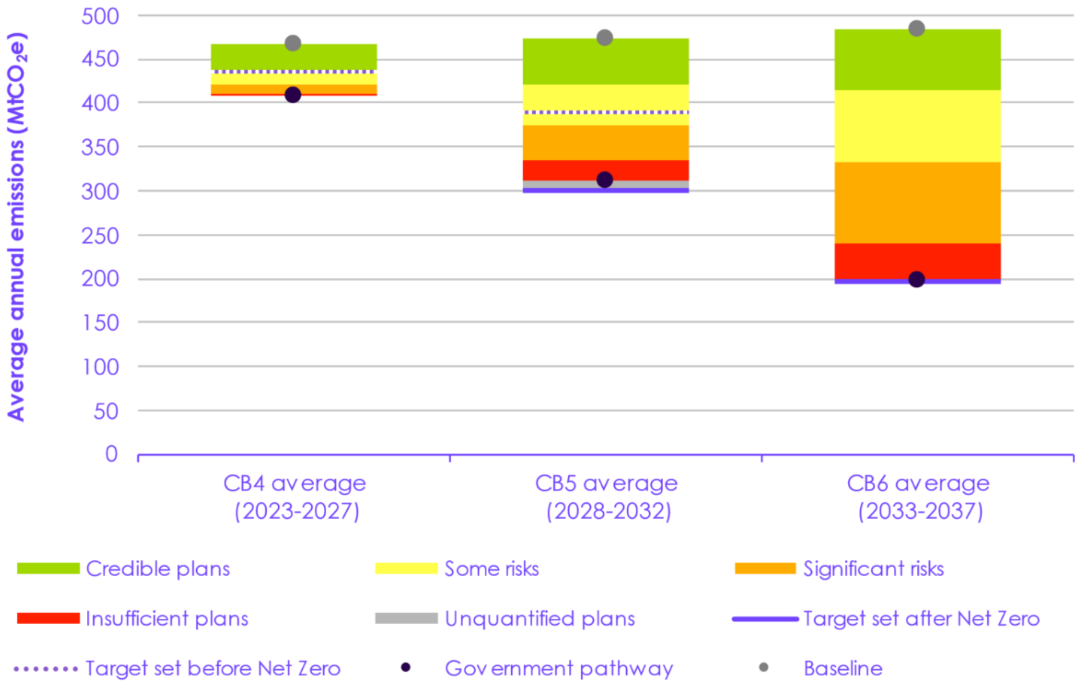
Note: Our approach, key assumptions and uncertainties are detailed later in this report. *Carbon budgets, adjusted for expected delivery in other sectors and in Northern Ireland based on CCC's Balanced Net Zero Pathway. **Based on NESO Future Energy Scenarios 2024 Counterfactual Scenario emissions for buildings and industry.

Introduction and summary

Current policies will be insufficient to meet carbon budgets in the 2030s

- The Climate Change Act 2008 sets legally binding carbon budgets to achieve Net Zero by 2050, with significant emissions reductions required by the 2030s
- The carbon budget framework recognises the importance of **early emissions reductions** on the path to 2050 Net Zero targets
- Based on CCC analysis:
  - The current rate of low-carbon investment in buildings and industry is **off track** to meet future carbon budgets
  - While there are credible plans in place to deliver some of the emissions reductions required to meet the fifth and sixth carbon budgets, **risks surround the remainder** of required savings (see RHS image)
- In addition, following the publication of the CCC's advice in early 2025, the Government is expected to legislate on the seventh carbon budget (2038-42)
- Further steps will need to be taken to accelerate emissions reductions to meet legally binding targets. As we later go on to explain, we have identified **practical, cost effective and realisable** ways in which the gas networks could support decarbonisation, contributing to 13 MtCO2e/year additional emissions savings in 2035

Projected greenhouse gas emissions across UK economy – CCC assessment of policies in place v. legal targets



Source: CCC 2024 Progress Report

Gas networks are already contributing to decarbonisation efforts

The GB gas network consists of 284,000km of pipelines[1] and currently serves ~700TWh/year[2] GB energy demand in buildings, power and industry. Network operators are currently supporting emissions reductions in several ways

Transporting low-carbon energy

- 128 biomethane sites currently connected to the gas grid, with capacity for over 10TWh of renewable gas production[3] (displacing natural gas consumption)

Reducing gas network energy use and emissions

- Since 2000, methane emissions from gas leakage in the network as a whole have fallen by 50%, predominantly through replacing iron distribution pipes with plastic[4] (current programme scheduled to continue to 2032, further reducing emissions)
- National Gas has started work to replace certain compressor units on the transmission network[5], which should further reduce emissions from venting and energy use

System integration and flexibility

- Energy stored within gas networks ("linepack") is a significant source of within-day flexibility (1.7TWh, equivalent to 188 Dinorwig-scale pumped hydro storage schemes[6]) - enables (among other uses) flexible gas-fired generation to back-up intermittent renewables and meeting peak heating demand

Image source: IGEM

Notes: 1. ENA Gas Goes Green. 2. FES 2024 Table ES.27 reports gas consumption (excluding exports) of 670TWh in 2023 and 750TWh in 2022. 3. IGEM. 4. UK Government 2022 Methane Memorandum. 5. NGT RIIO-3 Business Plan. 6. IGEM

In this report we consider how gas networks can contribute to further emissions reductions during the 2030s

Study goals

- Understand the different technical options for increasing gas networks' contribution to emissions reduction targets, with a focus on the 2030s
- Understand the policy and regulatory changes that could facilitate these technical options

Study tasks

1. **Feasible technical options**
2. **Costs, benefits and impacts**
3. **Policy and regulatory options**
4. **Areas for further research and innovation**

Quantitative and qualitative assessment

There are three routes by which gas networks can facilitate significant emissions reductions

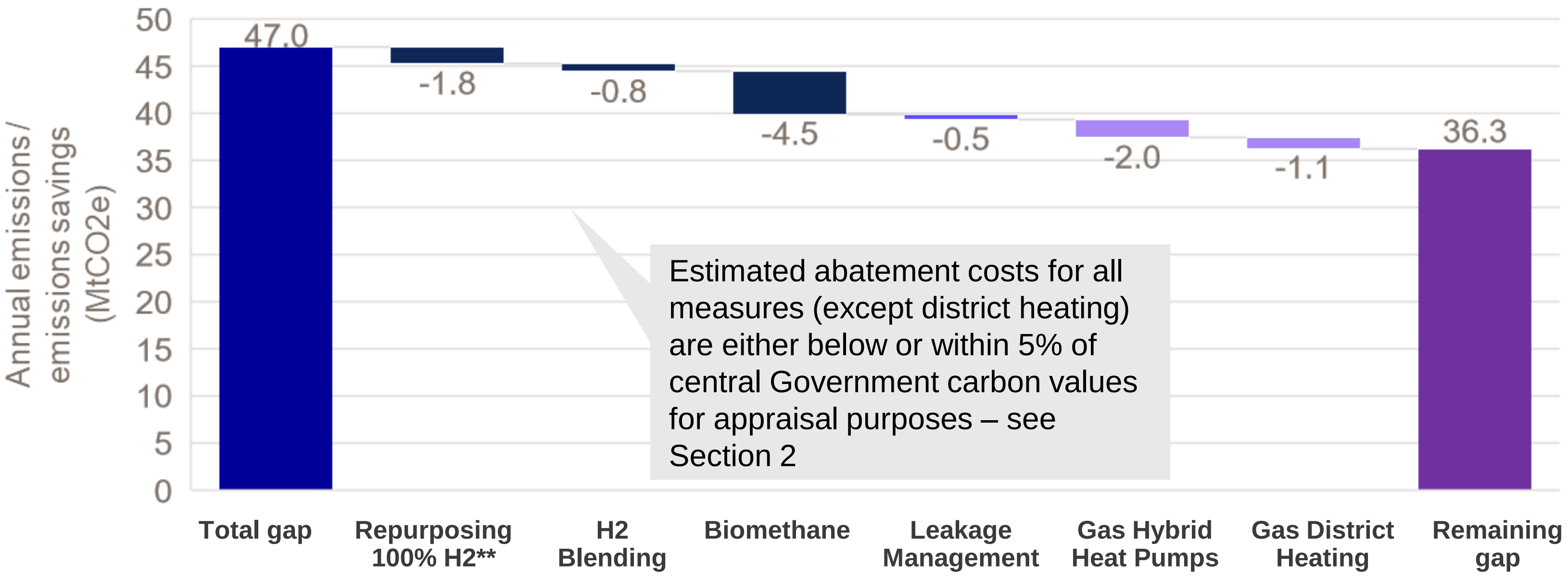
Transporting more low-carbon energy	Further reducing gas network energy use and emissions	Providing flexibility while supporting wider decarbonisation
• Accommodating increased biomethane uptake • Enabling CO_2 transport and low-carbon hydrogen through repurposed networks • Supporting hydrogen blending • Integrating synthetic methane	• Advanced leak detection and intervention (including further pipeline replacement post-2032) • Reducing compressor emissions	• Encouraging gas hybrid heating systems for difficult-to-electrify domestic properties • Increased district heating (with gas as back-up / peaking technology)

Key
- Full assessment (quantitative and qualitative)
- High level assessment only

The quantified measures could tackle 23% of the gap to meeting CB6 emissions goals for GB industry and buildings

- **Practical measures**. The measures for which we have quantified emissions savings are either deployed already today (biomethane, hybrid heating and gas in district heating) or are at an advanced stage of development (i.e. trials complete / ongoing)
- **Early emissions savings**. These measures can make a material contribution to meeting Carbon Budgets in the 2030s, at a time when the set of practical abatement options are more limited

Contribution of measures to addressing GB industry and buildings sector emissions gap*, 2035



Note: Given the project scope, a comprehensive assumptions review and modelling exercise was not possible for each measure. The quantitative results should therefore be viewed as being indicative only
*Gap defined as difference between emissions without policy action (based on FES 2024 Counterfactual) and required abatement in the buildings and industry sectors in GB. Required abatement for buildings and industry is equal to the average annual emissions implied by carbon budgets, less projected contributions to emissions reductions from other sectors and in Northern Ireland, based on the CCC Balanced Net Zero Pathway.
**For 100% hydrogen, our emissions savings focus on power and industry sectors. Low-carbon hydrogen derivatives are also expected to be relevant for aviation and shipping, though will be less reliant on networks (and, in the case of aviation fuels, unlikely to be deployed at scale until the late 2030s)

Key actions required from Government and Ofgem over the next few years to enable abatement potential

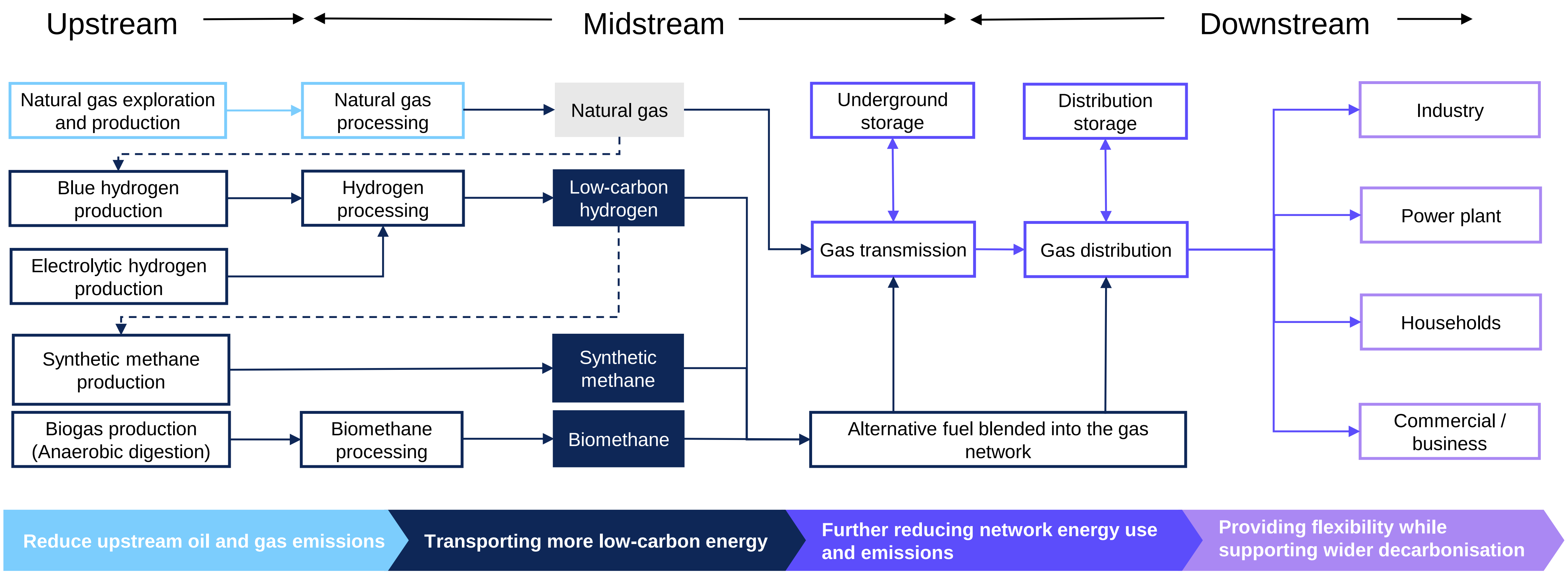
Category	Area	2025	2026	…
Transporting more low-carbon energy	Biomethane	By end-2025: Government to set ambitious goals for biomethane injections; Ofgem to confirm approach to supporting injection capacity increase during network price control period 2026-31	By end-2026: Government to specify the business model for biomethane production and injections post-Green Gas Support Scheme closure (in 2028) + re-examine propanation requirement	
	H2 blending	By end-2025: Government to make strategic decision on transmission-level blending & maintain work programme on distribution blending; establish H2 production business model for blending as an offtaker (enabling contract awards in 2026)		
	Repurposing networks for H2	H1 2025: Government and Ofgem to clarify how preparatory works for H2 networks will be financed		
Network energy use and emissions	Advanced leakage management	By end-2025: Ofgem to confirm approach to shrinkage / leakage measures going beyond current legislation (for both transmission and distribution) as part of Draft / Final determinations for network price control period 2026-31 (RIIO-3)		
	Reducing compressor emissions			
Flexibility + wider decarbon-isation	Hybrid heat pumps	By end-2025: Government to make financial support available for hybrid installations (e.g. via Boiler Upgrade Scheme) and/or reduce electricity levies		
	Gas district heating back-up		End-2026: Ensure sufficient funding for district heating to meet ambitions for growth following end of Green Heat Network Fund	

In addition:

- Government to make ongoing progress against H2 strategy (incl. support for H2 production, industrial transformation, and H2 networks)
- Gas networks (with Ofgem support) to continue research into how the contribution of gas networks can be maximised (see Section 4)

1. Feasible technical options assessed

We considered potential opportunities for reductions across the gas value chain…



…and focussed on measures that can be supported or delivered by the GB gas networks

Filter criteria	Category	Scope
• Involve contribution from GB gas networks • Feasible during 2030s	**Transporting more low-carbon energy**	• **In scope:** Biomethane, hydrogen blending, 100% hydrogen* (to extent facilitated by repurposing existing networks) • **High-level assessment:** Synthetic methane and repurposing for CO2 transport
	Further reducing network energy use and emissions	• **In scope:** Advanced leakage detection and management at distribution level • **High-level assessment:** Reducing emissions from gas-fired compressors at transmission level
	Providing flexibility while supporting wider decarbonisation	• **Focus** on use of gas networks (through use of natural gas, biomethane and/or hydrogen blending) to support **wider energy system flexibility in heating**
	Reducing upstream emissions	• **Out of scope** - difficult for gas networks to drive changes in upstream emissions – though upstream oil and gas industry plans to reduce emissions further from current level of ~1.6MtCO2e/year**

*For hydrogen, we focus on use cases for power and industry. We exclude shipping and aviation since there may only be a limited role for networks in facilitating hydrogen and its derivatives in shipping and aviation. We exclude hydrogen for heating from our analysis given the uncertainty regarding Government's future strategic decision in this area.
**See Section 3.1.3 UK 2022 Methane Memorandum and OGUK Methane Action Plan 2021

We have carried out a full assessment of the following measures

Transporting more low-carbon energy	**Biomethane**	• Industry sees potential to grow this renewable gas from current volumes (c. 10 TWh/year) to c.100 TWh or more by 2050, displacing natural gas consumption
	H2 blending	• While low-carbon hydrogen will mainly be produced for customers requiring pure H2, blending H2 in the natural gas network can de-risk early H2 production (and potentially, in turn, reduce renewable power curtailment) on a transitional basis while displacing natural gas consumption
	Repurposing networks for H2	• Gas networks can be repurposed for (100%) H2, supporting the delivery of the hydrogen economy at lower cost
Network energy use and emissions	**Advanced leakage management**	• Improved methane leak detection and better targeted interventions to reduce leakage at distribution, going beyond action implied by the iron mains risk reduction programme (IMRRP) that runs to 2032
Flexibility + wider decarbon-isation	**Hybrid heat pumps**	• Using heat pumps alongside other heat sources (e.g. gas boilers) can accelerate the decarbonisation of the majority of heating needs while harnessing the flexibility of the gas system to deal with peaks in heat demand during the coldest periods of the year
	Gas district heating back-up	

Given the unclear medium-term outlook for synthetic methane, we do not assess it in further detail in this report

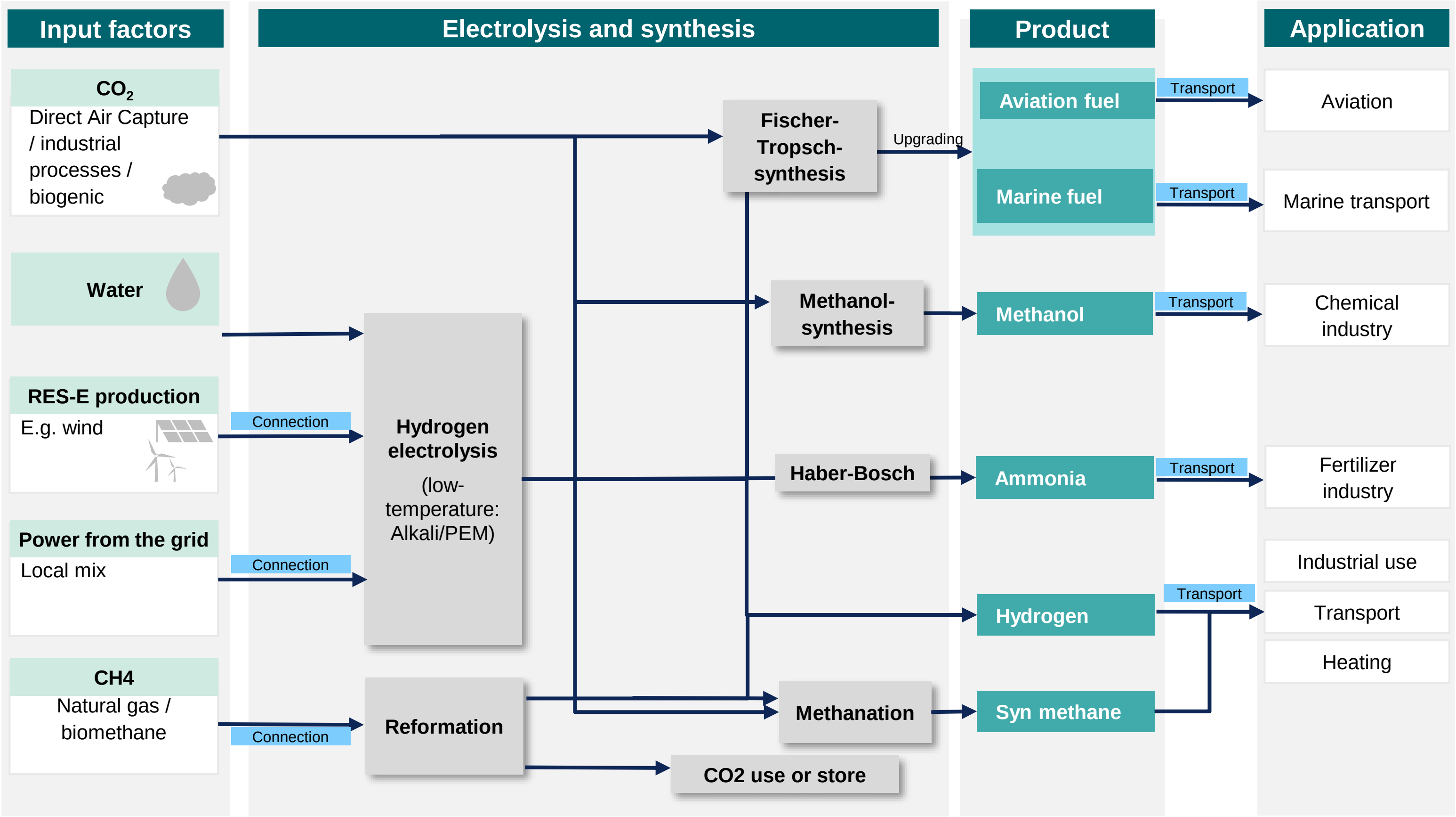


Image source: Frontier Economics

- Synthetic methane is produced from methanation of hydrogen (via a reaction with CO2)
- Depending on how the required hydrogen is produced, and how the CO2 is sourced, synthetic methane (or "e-methane") could be (near) carbon-neutral
- It could be used directly in the natural gas grid, and potentially produced on a decentralised basis
- It may be a competitive option for terminal imports of hydrogen-based energy carriers – and would be able to use existing import infrastructure
- However, given the required processing, compared to hydrogen, would involve further efficiency losses, it would add costs to hydrogen if produced domestically. Further, similarly to biomethane, its longer-term role in the mix as gas networks shift towards hydrogen need to be considered further
- Given synthetic methane is not yet deployed at commercial scale, we do not assess it in further detail in this report

Gas networks could contribute further through reducing the cost of CCUS in the wider economy

CO2 capture

CO_2 emitting sources

CO2 is captured from:
- industrial processes (e.g. cement, steel, and chemicals)
- power generation plants
- blue H2 production

CO2 transport

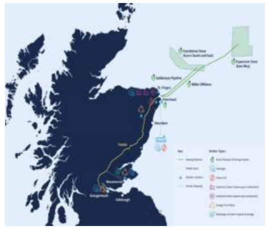
CO_2 transport modes

CO2 is then compressed and transported by pipelines, road, rails or ships

CO2 storage

CO_2 storage sites

CO2 either used (e.g. in industrial processes) or stored permanently underground



Source

Image source: Frontier Economics

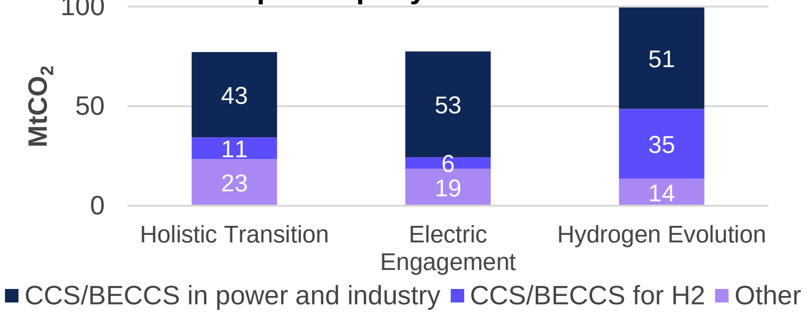
The UK government plans to establish CCS in four industrial clusters (HyNet the East Coast, the Viking project and the Acorn project) by 2030. The ambition is to capture 20-30MtCO2/year by 2030

National Gas is investing in CO2 transportation infrastructure – including repurposing 280km of gas pipelines, in Scotland

The UK has one of the largest potential CO_2 storage capacities in Europe with important geological assets as the UK Continental Shelf.

- The CCC has stated that CCS "is a necessity not an option" for decarbonising industry
- GB gas networks can enable these savings through repurposing current gas infrastructure for CO2 transport
- Some of these savings are already included in our quantitative analysis (e.g. via enabling low-carbon H2 production). Given data availability, we are unable at this time to robustly quantify the additional impacts associated with repurposing pipelines for CO2
- That said – impacts could be significant: e.g. FES 2024 pathways see 43-51 MtCO2/year captured by 2050 from the industry and power sectors, in addition to further contributions elsewhere (e.g. hydrogen production) – see Figure below

Carbon captured per year with CCS in 2050



Source: FES 2024

There is further potential to reduce emissions from compressors on the transmission system

- National Gas operators 60 compressor units at 21 compressor stations on the GB transmission network
- They are essential to maintaining the flow of gas in the network
- In FY23/24, GHG emissions from compressors were approx. 0.2MtCO2e (64% of National Gas' Scope 1 and Scope 2 GHG emissions), of which:
  - 0.19 MtCO2e resulted from gas combustion in compressor engines
  - 0.05 MtCO2e resulted from venting from compressors

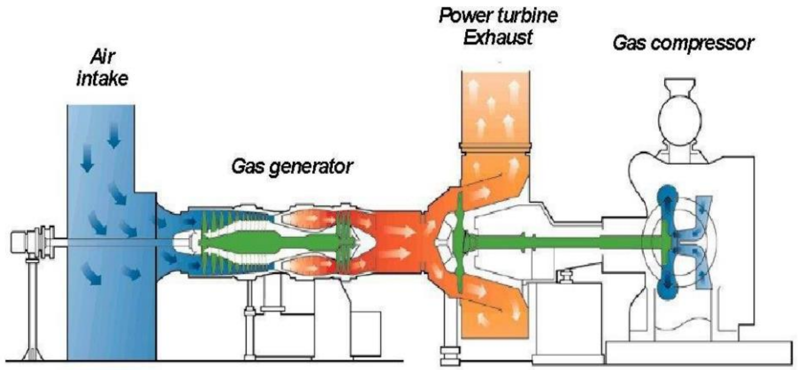


Figure 1: Compressor schematic showing engine and vent stack.

- National Gas is already upgrading some compressors to ensure compliance with air pollution legislation. This work will continue over RIIO-3 (2026-31) and will also support some reductions in GHG emissions
- National Gas has identified further measures that could be taken to reduce compressor GHG emissions over RIIO-3. Broadly, these involve:
  - Compressor shaft seal technologies to reduce methane leakage
  - Automated engine efficiency optimisers to reduce emissions from combustion
  - Use of low-carbon hydrogen (or blending) within compressors to reduce emissions from combustion
  - Replacing existing units with newer (gas- or electrically*-driven units)
  - Mobile flaring**
- We do not have sufficient data regarding the potential impact on GHG emissions of the additional measures above

Sources: National Gas website, accessed 27 January 2025; National Gas Network RIIO GT3 Network Decarbonisation Engineering Justification Paper; National Gas Annual Environmental Report 2023/24
*While electrically-driven compressor units would burn no gas, they are reliant on secure electricity supplies. As such, electrification would require gas back-up compressors to ensure gas can continue to be flowed in the event of an electricity supply emergency. **During pipeline maintenance, some gas may be vented – while flaring results in GHG emissions and air pollution, it mitigates the environmental impacts of venting, including methane emissions which are over 28 times more potent as a greenhouse gas than CO2)

2. Costs, benefits and impacts

We estimate the scale and cost-effectiveness of emissions savings for each measure

Scale indicator	Cost-effectiveness indicator
tCO2	$\frac{\text{£}}{\text{tCO2}}$

Cost-effectiveness indicator:

- £ → Net additional (annual) costs, relative to counterfactual
- tCO2 → Annual emissions savings, relative to counterfactual

To ensure a fair comparison between assets with different lifetimes, we annualise CAPEX (i.e. convert to an annuity value based on an assumed cost of capital and asset lifetime* – see Annex for details)

- We consider impacts relative to a baseline consistent with minimal policy change (NESO FES 2024 “Counterfactual” scenario)
- We calculate the two indicators (emissions savings and cost-effectiveness) separately for 2030, 2035 and 2040 (i.e. mid-point of carbon budget periods)
- Given the project scope, a comprehensive assumptions review and modelling exercise was not possible for each measure. The quantitative results should therefore be viewed as <u>being indicative only</u>
- Certain impacts (e.g. longer-term impacts, uncertainties) are assessed qualitatively (see next slide)

*This is consistent with the approach taken in CCC carbon budget analysis, as well as by DESNZ in energy sector cost-benefit analysis.

In the quantitative analysis, we compare each measure to a business-as-usual counterfactual

		Abatement activities (that gas networks could support)	Counterfactual (evolution of the sector without these activities)
Transporting more low-carbon energy	Repurposing H2	Industry and power H2 demand as per **FES Hydrogen Evolution** (with share attributed to network repurposing)	FES Counterfactual (primarily gas, with small quantities only of H2 demand)
	H2 Blending	FES Hydrogen Evolution	FES Counterfactual (no blending)
	Biomethane	ADBA projections (rising gradually from FES Counterfactual 2028 levels to 100 TWh by 2050)	FES Counterfactual (limited growth in biomethane)
Network energy use and emissions	Leakage management	Additional measures to reduce leakage from distribution going beyond IMRRP, including some pipeline replacement (though further savings beyond what we have considered may be possible)	Evolution of shrinkage based on FES Counterfactual gas demand
Flexibility + wider decarb-onisation	Gas hybrid pumps	FES Counterfactual with CCC Balanced Pathway projections for installed hybrid heat pumps	FES Counterfactual (individual gas boilers)
	District Heating	1 million additional district heating connections to 2030, with incremental demand assumed served by mix of large-scale heat pumps and gas boilers	FES Counterfactual (individual gas boilers)

We consider other aspects qualitatively

Feasibility and deliverability	• Is the technology ready to be deployed? Is the supply chain in place? • Can planning / permitting challenges be overcome?
Decarbonisation and environment	• Is the measure consistent with an efficient path to Net Zero by 2050? • Does the measure yield positive or avoid negative wider environmental impacts (air quality, natural environment, global emissions) compared to business as usual?
Security of supply	• Does the measure avoid risks to network resilience? • Does the measure allow the contribution of gas to whole system flexibility to be continued? • Does the measure reduce reliance on imports of gas?
Adaptability and flexibility	• Can the measure be adapted over time, in response to external developments? • Is the measure robust to different outturn scenarios (unexpected shocks / changes in government policy)?
Wider costs/ benefits	• Does the measure avoid other non-monetised negative impacts (e.g. health)? • Does the measure create other non-monetised positive impacts?
End user impact	• Can the measure be managed without significant disruption to end users?

Our RAG rating score for each is defined as follows:

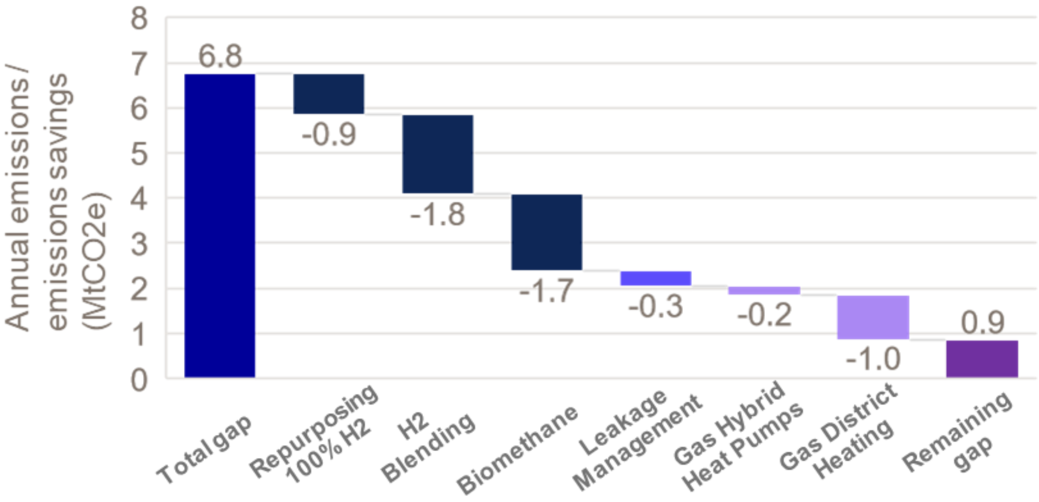
- Red: High risk of negative answer to each question
- Amber: Mixed positive and negative answers, or high degree of uncertainty
- Green: High likelihood of positive answer to each question

In contrast to the quantitative analysis, we are therefore not always comparing each measure to a business-as-usual counterfactual in this case.

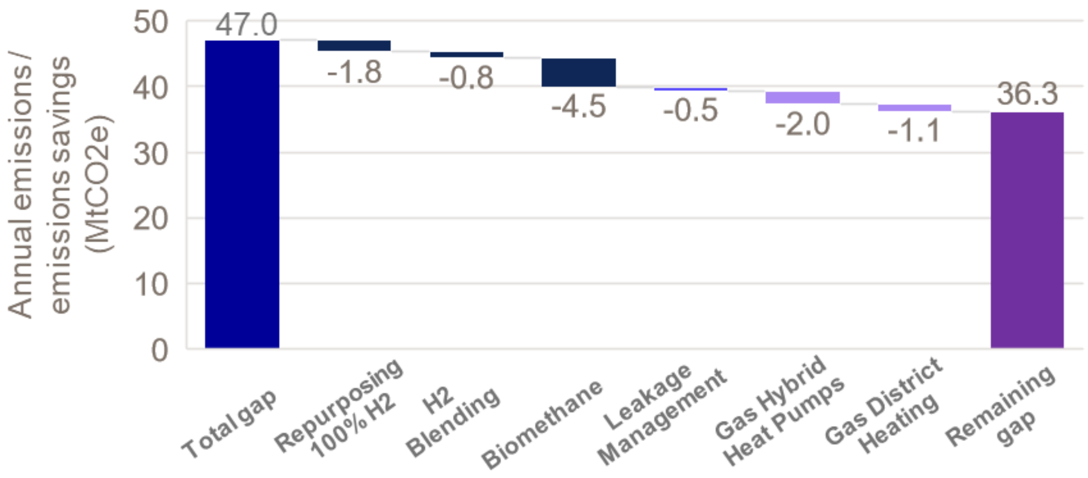
Note: The criteria above have been selected based on a synthesis of multiple sources, including Government publications (we have reviewed principles from UK Hydrogen Strategy, REMA consultation and CCUS business models update) and our work on the Assessment Methodologies (AM) project. The AM project involved comparing different Net Zero compliant options against multiple criteria, including core CBA elements and wider criteria. It was developed in conjunction with the gas networks, and secured buy-in from DESNZ and Ofgem.

Results: the measures identified could make a material contribution to the gap in required abatement in buildings and industry

2030 total emissions savings: 6MtCO2e (87% of gap); 0.2MtCO2e/year additional savings in the power sector



2035 total emissions savings: 11MtCO2e/year industry (23% of gap); 2MtCO2e/year additional savings in the power sector



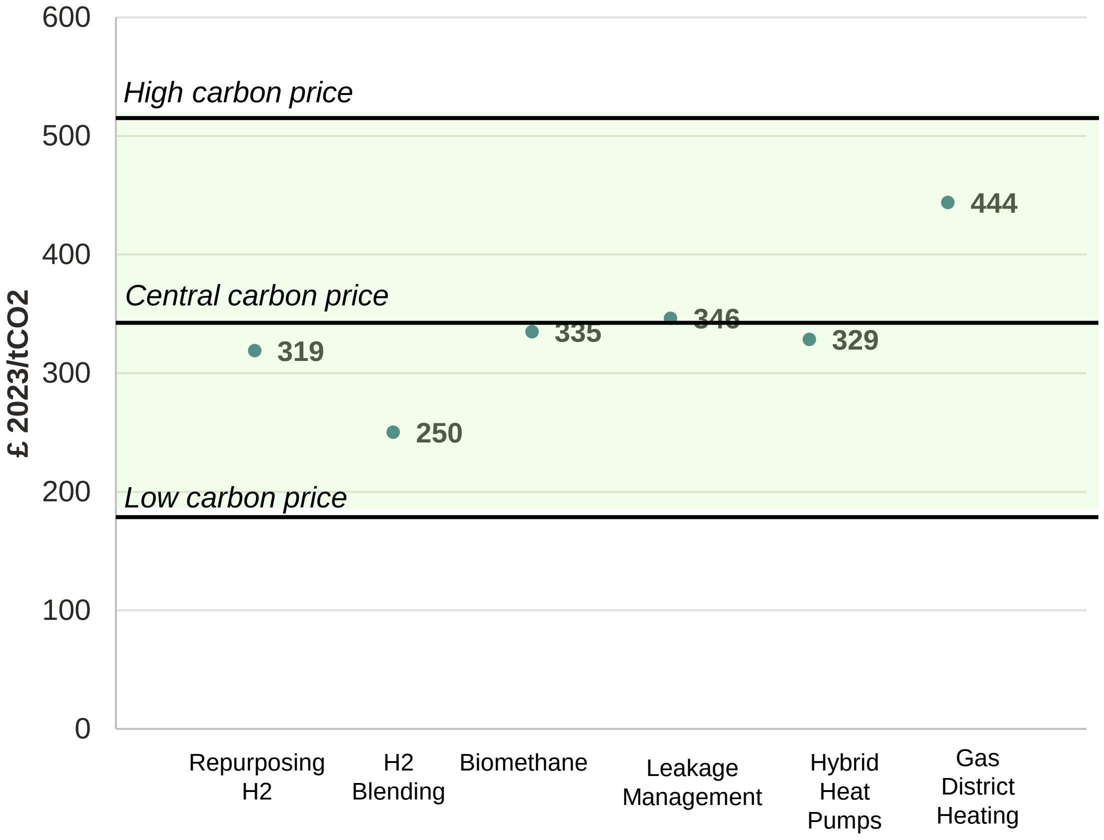
- “Gap” defined as difference between:
  - required abatement for GB buildings and industry (carbon budgets adjusted for expected contribution to abatement from other sectors and for Northern Ireland – based on CCC Balanced Net Zero Pathway); and
  - FES 2024 Counterfactual emissions for buildings and industry
- Emissions savings are calculated relative to FES Counterfactual

Results: Most of the abatement measures would be cost-effective (or close) at central carbon values in 2035

	Weighted average abatement cost	Government carbon values for appraisal (central)
2030	£326/tCO2e	£315/tCO2e
2035	£334/tCO2e	£340/tCO2e
2040	£333/tCO2e	£367/tCO2e

An abatement cost lower than the appraisal value for carbon indicates the measures are (on average) cost-effective at the appraisal value

Cost-effectiveness of individual measures compared to Government carbon values for appraisal purposes, 2035



Results: Gas network decarbonisation measures are feasible, and allow continued contribution to energy system flexibility

	Emissions savings (MtCO2e) - 2035	Cost-effectiveness (£2023/tCO2) - 2035	Feasibility and deliverability	Decarbon-isation and environment	Security of supply	Adaptability and flexibility	Wider costs / benefits	End user impact
Biomethane	4.5	335	Green	Green	Amber	Green	Amber	Green
H2 blending	0.8	250	Amber	Amber	Amber	Green	Amber	Amber
Repurposing networks for H2	2.0 (power) 1.8 (industry)	319	Green	Amber	Amber	Amber	Amber	Amber
Advanced leakage management	0.5	346	Green	Amber	Amber	Green	Amber	Green
Hybrid heat pumps	2.0	329	Green	Green	Amber	Green	Amber	Green
Gas district heating back up	1.1	444	Green	Green	Green	Green	Amber	Amber

Key

- Red: High risk of negative answer to each question
- Amber: Mixed positive and negative answers, or high degree of uncertainty
- Green: High likelihood of positive answer to each question

Biomethane: Assumptions

	Approach
Abatement activity	• Lead scenario considered in the ADBA's 2024 report (100TWh biomethane by 2050*, linear trajectory starting from FES 2024 Counterfactual levels in 2028)
Counterfactual scenario	• More limited growth in biomethane under FES 2024 Counterfactual
Emissions savings	• We assume biomethane injections displace natural gas use. We account for the emissions factor for biomethane as used by Government in its Green Gas Support Scheme Impact Assessment (30gCO2e/kWh) • We have not accounted for the potential to capture CO2 emissions from biomethane upgrading (though this would also come at additional cost)
Monetised costs	• Associated costs relate mainly to the difference between biomethane production costs and the wholesale price of natural gas (DESNZ central values for appraisal purposes) • We assume a £77/MWh levelized cost of biomethane in 2030 (based on ADBA's 2024 report) and apply a learning rate of 4.5%** based on OIES 2019 (p.21 – mid-point of 4-5% range cited in the study) • We have included costs for smart pressure control based on OptiNet study (for 0.253TWh biomethane, £600k CAPEX and £12k/year OPEX), with costs scaled up in proportion to assumed biomethane deployment • In-grid compression may be an alternative in some cases, but as this is uncertain and will depend on the situation, for simplicity here we have assumed only smart pressure control

*Estimates of GB-wide 2050 potential for biomethane vary significantly (including due to differences in assumptions regarding sustainable feedstock availability). While the ADBA estimates may represent a reasonably ambitious industry view they are towards the middle of the range of available projections for the UK (TIMES modelling for DESNZ Biomass Strategy 2023 projects 30-40TWh; Trinomics/LBST 2020 for European Commission projects ~70TWh; Ecotricity 2022 projects a lower bound of 288TWh, excl. seaweed & diet change). **I.e. for every doubling in biomethane production, we assume a 4.5% reduction in the levelized cost.

Biomethane: results

	Emissions savings, compared to counterfactual (MtCO2e/year)	Cost-effectiveness (£2023/tCO2e)
2030	1.7	353
2035	4.5	335
2040	7.3	319

Feasibility and deliverability	• Already being deployed at scale • While Government is seeking to understand barriers to obtaining planning consent there is not clear evidence that this is a significant barrier at present
Decarbonisation and environment	• As gas demand ramps down, net zero consistency can be achieved through use of biomethane to produce hydrogen or, in limited cases, blending* • Digestate can displace fossil fuel-based fertiliser and associated climate and soil impacts – provided wider environmental impacts can be mitigated • Combination of biogas upgrading with CCUS can contribute to further emissions savings
Security of supply	• Potential challenge with system operation given changes in flow patterns – particularly at LDZ-level – though network operators already investigating solutions and other jurisdictions (e.g. Denmark) have successfully managed high shares of biomethane. Supports gas system contribution to energy system flexibility • Reduced natural gas imports
Adaptability and flexibility	• Support for biomethane can be adapted over time as needs for low-carbon gases become clearer
Wider costs/ benefits	• No other wider costs / benefits identified • Uncertainty regarding costs of sustainably-produced biomethane and network integration costs (although latter likely to be small relative to production costs)
End user impact	• Quality standards for injection limit end-user impact

*See ARUP (forthcoming) "Biomethane and Hydrogen: Maximising the Role of Green Gas"

H2 blending: assumptions

	Approach
Abatement activity	• H2 blending in FES 2024 Hydrogen Evolution
Counterfactual scenario	• FES 2024 Counterfactual
Emissions savings	• We assume H2 blending (mix of electrolytic and blue H2 – see Annex) displaces natural gas use • We account for emissions from blue H2 production (95% CO2 capture rate based on DESNZ 2021 Hydrogen Costs report for ATR + CCS).

Monetised costs	• Associated costs relate largely to the difference between incremental H2 production costs for blending (Frontier estimates based on DESNZ Hydrogen Costs report – see Annex) and the cost of natural gas that is displaced (based on DESNZ central values for appraisal purposes)
	• Allowance also made for hydrogen injection sites to LDZ based on DESNZ 2023 blending consultation , Table 2
	    • CAPEX of £1,025,000 and OPEX (assumed fixed) £37,500 per 37,000 MWh/year injection capacity (2021 prices)
	    • Scaled up for level of H2 blending

Note: We do not quantify the impact of substituting natural gas with hydrogen blending on fugitive emissions. This is likely to be a conservative assumption, since hydrogen has a lower Global Warming Potential (GWP) than methane.

H2 blending: results

	Emissions savings, compared to counterfactual (MtCO2e/year)	Cost-effectiveness (£2023/tCO2e)
2030	1.8	240
2035	0.8	250
2040	N/A	N/A

No estimated emissions savings from H2 blending by 2040 (given blending's transitional role), but this is offset by additional savings from increasing use of 100% hydrogen

Feasibility and deliverability

- HyDeploy industry trials, demonstrations and tests to gather evidence to demonstrate whether and/or how blending can be used safely in the GB gas distribution networks have been completed or are ongoing. Government intends to review this evidence ahead of final decision / further legislation on blending.
- Future Grid is leading trials to assess the safety of blending in the transmission system

Decarbonisation and environment

- Consistent with Net Zero as a transitional measure only (Government's view is that blending can help de-risk early investments in H2 production
- Unlikely to have wider environmental benefits

Security of supply

- Blending would make network operation more complex
- Blending allows the contribution of gas to whole system flexibility to be continued and reduces reliance on imports of gas, where electrolytic hydrogen is used

Adaptability and flexibility

- Allowed blending level can be adjusted over time in response, for example, to changes in costs or deliverability challenges.
- Measure is robust to changes in policy (e.g. slower or faster adoption of the hydrogen economy).

Wider costs/ benefits

- No other wider costs / benefits identified
- Uncertainty regarding hydrogen production costs and blending costs (although latter likely to be small relative to production costs)

End user impact

- Technological solutions (e.g. deblending) may be required for sensitive end users (industrial sector).

Repurposing networks for 100% H2: Assumptions

	Approach
Abatement activity	• Evolution of H2 demand use in industry and power as per FES 2024 Hydrogen Evolution
Counterfactual scenario	• Limited H2 demand in industry and power as per FES 2024 Counterfactual

Emissions savings	• Based on H2 demand displacing natural gas in industry and power.
	• We attribute a share of the emissions savings from enabling hydrogen in these sectors to repurposing of gas networks, based on the share of planned future hydrogen network length currently expected to be comprised of repurposed lines:
	  • 25% for transmission based on Project Union plans
	  • 28% for high-pressure distribution (based on regional decarbonisation pathways report for WWU)*
	• Re-purposing is phased in linearly over 2030-2040.

Monetised costs	• **Network repurposing costs:** We assume per km pipeline repurposing CAPEX based on European Hydrogen Backbone 2023. For simplicity, given network OPEX is unlikely to make a material difference to overall costs, we assume H2 network OPEX is identical to natural gas network OPEX in the counterfactual.
	• **Appliance costs:**
	  • For industry, we have based CAPEX for H2 retrofit on Element Energy et al (2019) "Conversion of Industrial Heating Equipment to Hydrogen". As a simplification, we have assumed no difference in fixed OPEX
	  • For power generation, we assume costs of retrofitting gas-fired generation to H2 based on DESNZ**
	• **Fuel costs:** We calculate the change in the costs of serving energy demand with low-carbon hydrogen (see Annex for details of calculation) instead of with natural gas (DESNZ central long-run variable supply costs)

*For simplicity, we assume all future power H2 demand will be connected to hydrogen transmission and all future industrial H2 demand to hydrogen distribution, though this has limited impact on our results since the assumed shares of repurposing are similar for both transmission and distribution. **Based on DESNZ 2023 "The Need for Government Intervention to Support Hydrogen to Power" we assume H2P retrofit CAPEX is equal to 50% of new-build CAPEX. We assume new-build CAPEX in line with DESNZ 2023 Electricity Generation Costs. *** We assume that repurposing networks for 100% H2 and leakage reduction measures apply to at different LDZ pressure tiers, and hence do not interact.

Repurposing networks for 100% H2: results

	Emissions savings, compared to counterfactual (MtCO2e/year)	Cost-effectiveness (£2023/tCO2e)
2030	0.9 (industry) / 0.2 (power)	250
2035	1.8 (industry) / 2.0 (power)	319
2040	2.2 (industry) / 3.2 (power)	338

Feasibility and deliverability	• GB networks are currently evaluating the potential for repurposing. However, it is technically feasible; construction has started in the Netherlands on a network involving repurposed gas network
Decarbonisation and environment	• Risk of partial stranding of network assets should future H2 demand turn out to be lower than expected (though risk more limited for re-purposing as compared to new-build) • Reduces upstream emissions associated with gas production, to extent electrolytic hydrogen is used. • Serving H2 demand through electrolysis places demand on water supply – although networks can mitigate impacts by providing more optionality regarding siting.
Security of supply	• Repurposing may have negative impacts on resilience of the remaining gas network • Connectivity with hydrogen storage, H2P and electrolysis enables whole energy system flexibility • Reduces reliance on imports of gas, where electrolytic hydrogen is used
Adaptability and flexibility	• Roll-out is capital-intense, and may be difficult to adjust quickly in response to a changing environment. However, H2 networks can be rolled out cluster by cluster.
Wider costs/ benefits	• No other wider costs / benefits identified • Uncertainty regarding hydrogen production costs and costs of industrial / power retrofit
End user impact	• End-users will need to switch / adapt to new technology (though this would be the case for all decarbonisation options)

Advanced leakage management: assumptions

	Approach
Abatement activity	• **Factual scenario:** Additional leakage management measures implemented, beyond IMRRP
Counterfactual Scenario	• Shrinkage consistent with FES 2024 Counterfactual levels
Emissions Savings	• FES 2024 provides projections of "shrinkage" (gas "lost" from gas networks) for transmission and distribution combined. We assume the split of shrinkage between transmission and distribution remains constant going forwards, at 2024 levels (approx. 70:30 split based on NGT data). We assume further (based on GDN Shrinkage Model Review 2020) that leakage accounts for 95% of the Gas Distribution Network (GDN) shrinkage figure. • In line with Cadent's RIIO-3 Business Plan projections, we assume the implementation of advanced leakage detection and interventions can contribute to a further 10% reduction in leakage of gas at distribution networks by 2030, beyond that enabled by the Iron Mains Risk Reduction Programme (IMRRP). We assume continued reductions post-2030, at a slower rate (15% by 2035 and 20% by 2040). • Consistent with DESNZ reporting, we use the IPCC 5th Assessment Report published 100-year Global Warming Potential (GWP) for methane (28) to calculate the CO2-equivalent emissions associated with methane leakage
Monetised costs	• **Leakage analytics / platform:** One-off CAPEX of £67 million (2023 prices) over 2026-30 and annual OPEX of £ 44 million (based on costs for Cadent's proposed Advanced Leakage Detection / Digital Platform – from Table 15 Cadent RIIO-3 Business Plan, scaled up for GB distribution based on estimated network length at 2026 from Ofgem - technical annex part two - Cost Drivers • **Ongoing costs of intervention:** REPEX of £826 million over 2026-30 (based on Cadent estimates for RIIO-3 for Advanced Leakage Intervention, scaled up for GB based on distribution network length). We assume continued REPEX over 2031-40, at a slower rate (£826 million spread over 10 years).

*The impact on leakage of measures – such as hybrid heat pumps - that reduce gas consumption is considered separately when calculating their respective emissions savings.

Advanced leakage management: Results

	Emissions savings, compared to counterfactual (MtCO2e/year)	Cost-effectiveness (£2023/tCO2e)
2030	0.3	333
2035	0.5	346
2040	0.5	316

Feasibility and deliverability	• Trials during RIIO-2 have demonstrated Digital Platform for Leakage Analytics • Interventions such as pipeline replacement are standard work for GDNs
Decarbonisation and environment	• Consistent with Net Zero (as long as interventions are selected to as to minimise risk of stranded assets) • Unlikely to have wider environmental benefits
Security of supply	• Allows the contribution of gas to whole system flexibility to be continued • Reduces reliance on imports of gas
Adaptability and flexibility	• One-off costs for platform, but decisions on subsequent interventions to address leakage can be taken on case-by-case basis depending on outlook for gas demand
Wider costs/ benefits	• Health and safety benefits from reduced leakage • Precise costs and emissions savings to be realised as a result of improved leak detection and monitoring are uncertain
End user impact	• No direct impact on end users

Hybrid heat pumps: Assumptions

Measure	Approach
Abatement activity	• CCC 6th Carbon Budget analysis projects 1.4 million (hydrogen) hybrid heat pumps by 2035 (Balanced Pathway scenario). We assume a similar number of hybrid installations, added to existing gas boilers
Counterfactual scenario	• Continued natural gas use (individual gas boilers) as per FES 2024 Counterfactual
Emissions savings*	• We assume 14000 kWh annual gas consumption per boiler in the counterfactual (consistent with typical semi-detached property usage) • We assume 85% of counterfactual gas consumption is displaced per hybrid installation • Heat pump electricity needs (and displaced gas consumption) calculated based on gas boiler efficiency and heat pump COP (87% and 3.5 respectively as per CCC 6th Carbon Budget analysis) • Emissions from displacement of gas and increase in electricity demand accounted for using DESNZ central emissions factors for use in appraisal (assuming domestic consumption profile for electricity)

Monetised costs	• **Fuel costs:** Changes in gas and electricity supply costs based on central DESNZ appraisal values (assuming domestic consumption profile for electricity)
	• **Appliance costs:**
	    • No change in gas boiler fixed costs (as assumed to be same in factual and counterfactual)
	    • Hybrid heat pump costs (factual): Assume 5kW size per appliance. CAPEX and installation costs consistent with CCC 6th Carbon Budget analysis

*We have made a small adjustment to estimated emissions savings to account for the fact that reduced gas demand from a switch to heat pumps could lead to reduced shrinkage (and therefore reduce the impact of leakage management measures).

Hybrid heat pumps: Results

	Emissions savings, compared to counterfactual (MtCO2e/year)	Cost-effectiveness (£2023/tCO2e)
2030	0.2	367
2035	2.0	329
2040	2.0*	318

- Estimated emissions savings are based on uptake of hybrid heat pumps as per CCC CB6 projections
- Should further deployment be deemed appropriate (for example, due to challenges in achieving electric-only heat pump roll-out goals), further savings would be possible
- As an illustration, doubling the assumed deployment of hybrids would lead to an additional 2 MtCO2e/year savings in 2035

Feasibility and deliverability	• Relatively mature technology, and relatively mature supply chain. Installation is likely to be relatively straightforward, without the need for major retrofits. Planning and permitting unlikely to pose barriers
Decarbonisation and environment	• Assuming a 15-year lifetime of technologies, installation of hybrid heat pumps until 2035* can be consistent with Net Zero. • Will reduce air quality impacts, relative to continued gas boiler usage
Security of supply	• Allows the contribution of gas to whole system flexibility to be continued, though reduced off-peak gas demand may affect system operation – extent will depend on whether roll-out is concentrated or spread out geographically • Reduces reliance on imports of gas, relative to a counterfactual of continued gas boilers
Adaptability and flexibility	• Roll out is incremental so can be adapted over time in response to changes in costs / deliverability • Measure is robust to changes in policy (e.g. adoption of hydrogen for heating in certain areas)
Wider costs/ benefits	• No other wider costs / benefits identified
End user impact	• Installation is relatively simple

*Continued installation beyond 2035 could be consistent with Net Zero provided appliances can run on is low-carbon fuels that are available in sufficient quantities. Assuming deployment based on the CCC Balanced Pathway trajectory for hybrids continues post-2035, savings in 2040 could be 7.4MtCO2/year (i.e. 5.4MtCO2/year higher than stated in the table above).

Using gas as back-up for district heating: Assumptions

Measure	Approach
Abatement activity	• We assume an additional 1 million households connected to district heating (DH) networks by 2030, with these networks using heat pumps and gas boilers as back-up. This is broadly consistent with growth in CCC projections for low-carbon district heating to 2030*.
Counterfactual scenario	• Continued natural gas use (individual gas boilers) as per FES 2024 Counterfactual
Emissions savings**	• We assume heating needs per household of 7000 kWh – i.e. for a smaller-than-average property (consistent with values cited in DESNZ's Impact Assessment on Heat Networks Regulation). We assume heat network losses of 21% • Electricity needs for large-scale heat pumps (and displaced gas consumption) calculated based 87% gas boiler efficiency (based on CCC CB6 analysis) and COP of 3.7 for large-scale heat pump (based on ILF et al (2017) for the European Commission) • Emissions from displacement of gas and increase in electricity demand accounted for using DESNZ central emissions factors for use in appraisal (assuming domestic consumption profile for electricity)

Monetised costs	• **Fuel costs:** Changes in gas and electricity supply costs based on central DESNZ appraisal values (assuming domestic consumption profile for electricity)
	• **Appliance costs:**
	  • Factual DH CAPEX (factual): Long-run average heat network cost of £23/MWh_{th} (2023 prices) based on Element Energy 2015
	  • Installation costs per household: hot water tank and heat interface unit / heat metering costs - both based on Element Energy analysis for CCC CB6
	  • Factual large-scale heat pump CAPEX / fixed OPEX: ILF et al (2017)
	  • Factual back-up boiler CAPEX / fixed OPEX: ILF et al (2017)
	  • Counterfactual individual gas boiler CAPEX / fixed OPEX based on CCC CB6 analysis. We assume one-third of households would have had to replace boilers by 2030 in the counterfactual

*The CCC 6th Carbon Budget Balanced Pathway scenario sees growth in DH connections to about 4 million households by 2050. The CCC projections assume all incremental DH is served by low-carbon sources from 2025 onwards.

** We have made a small adjustment to estimated emissions savings to account for the fact that reduced gas demand from a switch to district heating could lead to reduced shrinkage (and therefore reduce the impact of leakage management measures).

Using gas as back-up for district heating: Results

	Emissions savings, compared to counterfactual (MtCO2e/year)	Cost-effectiveness (£2023/tCO2e)
2030	1.0	506
2035	1.1	444
2040	1.2	427

Feasibility and deliverability	Green	• Technology is mature, supply chains are in place and no planning or permitting barriers are expected
Decarbonisation and environment	Green	• Assuming a lifetime of 15-20 years, is consistent with Net Zero for investments in gas-boiler back-up up to 2030. • Will reduce air quality impacts, relative to individual gas boiler usage
Security of supply	Green	• Allows the contribution of gas to whole system flexibility to be continued, though reduced off-peak gas demand may affect system operation • Reduces reliance on imports of gas, relative to continued use of gas only for heating.
Adaptability and flexibility	Green	• Network can be rolled out incrementally, and adjusted where required • Heat sources connected to network can also be adapted over time
Wider costs/ benefits	Amber	• Avoids other non-monetised costs but does not create benefits.
End user impact	Amber	• Some disruption for end-users during connection to heat network (though many alternative options for heat decarbonisation would involve some disruption)

3. Policy and regulatory options

Enabling the potential will require co-ordinated action between Government and Ofgem

	Transporting more low-carbon energy	**Further reducing gas network energy use and emissions**	**Providing flexibility while supporting wider decarbonisation**
	Business models consistent with high ambition for low-carbon energy	Financing network expenditure	Addressing barriers to low-carbon technology adoption
Key barriers	Externalities & barriers related to cost structure (e.g. of biomethane, hydrogen) relative to fossil alternatives	Need for strategic investment decisions given lead times for network investments and uncertainty regarding future use	Externalities & barriers related to cost structure (e.g. H2P) + additional factors for residential customers (e.g. affordability / behavioural barriers)
Example solutions	Levers sit principally with Government (e.g. taxation, financial support, business models)	Levers sit principally with Ofgem (e.g. allowed expenditure, incentives and uncertainty mechanisms in price controls)	Levers sit principally with Government (including local). Wide range of interventions including financial (tax, subsidy) and product standards

Supply chain / skills barriers likely to be relevant across all measures, and potentially require supportive policy action (though not considered in further detail in this report). (Note: All gas networks have their own workforce and supply chain resilience strategies in place)

Biomethane: need for clarity on support post-2028 and on connection capacity

Key barriers	Current status	Required actions to enable potential
Higher cost compared to fossil fuel alternatives	• Currently, the Green Gas Support Scheme (GGSS) supports biomethane, and has been recently extended to new applications until March 2028. Biomethane is also eligible under the Renewable Transport Fuel Obligation (RTFO) • Government is considering options for a future policy framework for biomethane to follow the closure of the GGSS	• By end-2025: Government to set ambitious goals for biomethane injections • By end-2026: Government to specify the business model for biomethane production and injections post GGSS-closure (in 2028)
Biomethane producers (particularly at distribution-level) may be required to add propane when injecting to the grid to meet gas quality / calorific value requirements. This adds costs and reduces carbon savings	• Biomethane industry and gas networks are exploring technical solutions within the current regulations • DESNZ has stated it will review the relevant regulations	• By end-2026: DESNZ/HSE to re-examine propanation requirement
Need for network capacity to connect additional biomethane potential	• Ofgem recognises need for GDNs to be able to roll out technologies to facilitate biomethane connections and fund activities in this area during RIIO-3 (period 2026-31). Cadent currently discussing mechanism with Ofgem to address uncertainty over volumes and connection costs associated with future biomethane under Heat Policy re-opener for RIIO-2 • Ofgem recognises role of biomethane connections to the National Transmission System (NTS) for RIIO-3, and is also working with industry and Government to determine if licence/UNC changes are needed to facilitate connections	• By end-2025: Ofgem to confirm approach to supporting biomethane injection capacity increase during RIIO-3 • Ahead of RIIO-4 (and beyond): Ofgem (collaborating with Government) to design mechanisms to enable a rapid and large-scale expansion in capacity for biomethane injections

Blending: implement overarching framework and establish HPBM model for blending as offtaker

Key barriers	Current status	Required actions to enable potential
Lack of overarching legislative / commercial framework	• Government's December 2023 strategic decision indicated its support for hydrogen blending into the distribution network in principle, though further work will be required, including health and safety reviews, potential legislation changes. • Government has stated it will consult on transmission-level blending within GB in early 2025, with the aim of making a strategic policy decision on whether or not to support transmission-level blending in 2025	Previous Frontier analysis indicated that implementing a commercial framework for blending may take 3-5 years. To enable blending by 2030, it will therefore be important that Government maintains its work programme: • End-2025: Government to make strategic decision on transmission-level blending • 2025: Government to maintain work programme on distribution blending
For networks: uncertainty regarding coverage of blending-related network costs	• During RIIO-3, Ofgem decided that has funding for blending-related costs will be provided via Uncertainty Mechanisms	• No specific action identified for RIIO-3 • Ahead of RIIO-4: Ofgem to identify whether specific regulatory mechanisms are needed for blending-related costs
For H2 production: uncertainty regarding ability to sell blended output on gas network	• Government as stated it will continue to engage with stakeholders on potentially incorporating blending as an offtaker into Hydrogen Production Business Model (HPBM) support	• By end-2025: Government to establish HPBM model for blending as an offtaker (enabling contract awards in 2026)

H2 repurposing: provide clarity on financing of preparatory work for H2 networks

Key barriers	Current status	Required actions to enable potential
High costs of H2 production compared to fossil alternatives and of H2-consuming technologies (i.e. H2P / H2 industrial technologies)	• Government has developed the HPBM (including holding two Hydrogen Allocation Rounds), and has has supported industrial low-carbon technology deployment under the Industrial Energy Transformation Fund (IETF) and is developing a business model for H2P	• Ongoing: Government to continue the actions in its Hydrogen Strategy, including confirming the approach to future Hydrogen Allocation Rounds, elaborating on the approach to H2P, and committing to an extension of the IETF.
Co-ordination across value chain in early stages of H2 market development (production, transport capacity and consumption need to develop in tandem)	• The Government is planning a Hydrogen Transport Business Model (HTBM) to select and finance the construction of future H2 networks (including those from repurposed gas networks) • During RIIO-2, Ofgem has funded some GDN/NGT Devex (such as feasibility studies) for H2 networks via the Net Zero Pre-construction Works and Small Net Zero (NZASP) Re-opener. For RIIO-3, Ofgem's minded to position is that Devex for new projects should be out of scope, on the basis that these costs may be recoverable via HTBM, though Ofgem is open to receiving proposals for preparatory works from gas networks, subject to demonstrable clear benefits to customers and work not being funded by HTBM. HTBM guidance published in Summer 2024 states that having completed FEED is a requirement for eligibility for HTBM.	There is a key gap in relation to devex, which can help keep the option open to invest in H2 networks, should they later be deemed necessary to support decarbonisation: • Early 2025: Government and Ofgem to clarify how preparatory works for H2 networks will be financed

Network emissions: Ofgem to continue approach to supporting shrinkage reductions

Key barriers	Current status	Required actions to enable potential
Advanced leakage management (distribution): Need for regulatory approval of costs	• IMRRP will continue to drive lower shrinkage. However, this is part of the counterfactual. Going beyond IMRRP, Ofgem has decided to introduce Shrinkage UIOLI for RIIO-3, which will fund measures such as installation of pressure management equipment and further shrinkage-related innovation projects. • Ofgem has separately decided to fund rollout of leakage detection technologies – with an appropriate mechanism to be developed at the time of Draft Determinations to fund roll-out	• End-2025: Ofgem to confirm approach to shrinkage / leakage measures going beyond IMRPP as part of Draft / Final determinations for RIIO-3
Compressor emissions reductions (transmission): Need for regulatory approval of costs	• NGT obliged under the Combustion Plant Directive to control and manage air pollution from gas-fired compressors. Ofgem intends to retain the current Compressor Emissions Re-opener to deliver projects that have already been started and to finance any new projects for RIIO-3, including FEED studies. • In addition, Ofgem has decided to retain a GHG incentive and has encouraged NGT to use RIIO-3's innovation schemes and/the Net Zero and Re-opener Development Fund (NZARD) to bring forward additional projects that reduce shrinkage volumes.	• End-2025: Ofgem to confirm approach to shrinkage measures as part of Draft / Final determinations for RIIO-3

Heating: Government to address financial barriers to uptake of hybrids

Key barriers	Current status	Required actions to enable potential
Hybrid heat pumps: • High electricity taxes / levies • Affordability	• Government is taking a range of actions to support low-carbon heating in residential properties, including the Clean Heat Market Mechanism and grants under the Boiler Upgrade Scheme. However, gas hybrid heat pumps are not eligible for the latter (not even for reduced grant levels)	• End-2025: Government to make financial support available for hybrid installations (e.g. via Boiler Upgrade Scheme) and/or reduce electricity levies
Specific barriers for connecting to **district heating** include: • Gaps in local energy planning • Uncertainty for customers regarding costs • Barriers to network construction	• Government has legislated to introduce Heat Networks Zoning • Ofgem will become heat network regulator from 2025 – ensuring greater consumer protection while allowing licensed network developers greater rights to develop networks • Funding including Green Heat Network Fund (GHNF) is available that supports heat production, heat distribution and upgrading secondary systems (such as heat interface units) within consumer premises. Funding will be provided to 2027/28	• End-2026: Ensure sufficient funding for district heating to meet ambitions for growth following end of GHNF

4. Areas for further research

Further research could support an improved understanding of the gas system's contribution (1/2)

In this section, we highlight some key areas for research in relation to the measures considered. Our suggestions are non-exhaustive, and focus on supporting a better understanding of the potential emissions savings from each measure, how these savings might be maximised, and how they could be built on to unlock further savings.

Transporting more low-carbon energy

Biomethane	• As highlighted in Section 2, based on industry projections, biomethane could play a significant role in supporting decarbonisation goals. However, as we have noted, there is uncertainty (and differing views between industry and Government) regarding the availability of sustainable feedstock for the UK and cost-effectiveness of production potential. Ensuring a **solid evidence base regarding costs and potential** would help in form future energy system planning. • Alongside the above, there is a need to better understand the **challenges and opportunities associated with capture / use of biogenic CO2 from biogas upgrading** • In addition to delivering known solutions, networks should continue to **evaluate and investigate strategies for accommodating biomethane at least cost** (potentially supported by RIIO-3 innovation and net zero delivery mechanisms)
H2 blending	• HSE is reviewing safety evidence for blending, including evidence from industry trials • As part of the wider hydrogen blending safety review, the government is assessing aspects such as the performance and accuracy of gas meters to determine if any modifications or cost is necessary, or more generally any potential impact on industrial users connected to the gas distribution network from receiving hydrogen blends. The Government will need to carry out a **similar assessment in relation to transmission**

Further research could support an improved understanding of the gas system's contribution (2/2)

Transporting more low-carbon energy	**Repurposing networks for H2**	• There is uncertainty regarding extent of hydrogen's role in decarbonising, and there is already work ongoing to understand this further (for example in heating). • However, there is already consensus on the nature (if not the full extent) of the role hydrogen can play in industry and power. Networks will be key to serving this demand. • GB networks are already evaluating the potential for repurposing gas networks for hydrogen. To support this process, there is a **need for robust frameworks to assess resilience needs across energy carriers**, which could help guide optimal decisions around the extent and staging of repurposing works.
Network energy use and emissions	**Advanced leakage management**	• Trials have already taken place in relation to improved leakage analytics and measurement. As Ofgem notes, rolling this out more widely will provide better quality data regarding leakage. • This data may provide the opportunity for **further trials to evaluate the effectiveness of specific approaches to addressing leakage.**
	Compressor emissions	• Further **research on compressor technologies** such as Variable Speed Drives which (according to NGT) are still in early stages of development, and which could make significant contributions to decarbonisation.
Flexibility + wider decarbon-isation	**Hybrid heat pumps**	• Support trials to **establish how hybrid systems can best contribute to emissions savings and energy system flexibility** (as suggested by Cadent).
	Gas district heating back-up	• Given a revised policy framework for district heating is in the process of being implemented, the near-term priority may be to **evaluate / understand its effectiveness** over the coming years.

Annex: technology lifetimes / cost of capital & hydrogen production cost assumptions

Assumptions on technology lifetimes and cost of capital

	WACC (pre-tax, real)	Lifetime (years)	Source / Note
Gas networks (PE pipelines, H2 blending points, biomethane costs)	7.5%	90	Consistent with Assessment Methodologies* approach developed with gas networks
Leakage analytics platform	7.5%	15	Frontier assumption. We have assumed shorter economic life compared to gas networks due to risk of obsolescence associated with IT solutions.
H2 networks	7.5%	90	Consistent with Assessment Methodologies approach developed with gas networks
H2P retrofit	10%	25	DESNZ power generation cost assumptions
Heating technologies (individual)	3.5%	15	Consistent with analysis supporting CCC CB6 pathways
Large scale heat pump	3.5%	25	Cost of capital based on CCC CB6 supporting analysis. Lifetime based on ILF et al
Large scale gas boiler	3.5%	20	Cost of capital based on CCC CB6 supporting analysis. While ILF et al suggests 35 years we have assumed 20 years to ensure consistency with 2050 net zero goals.
H2 production	10%	30 (electrolysis) 40 (methane reformation)	DESNZ Hydrogen Costs report

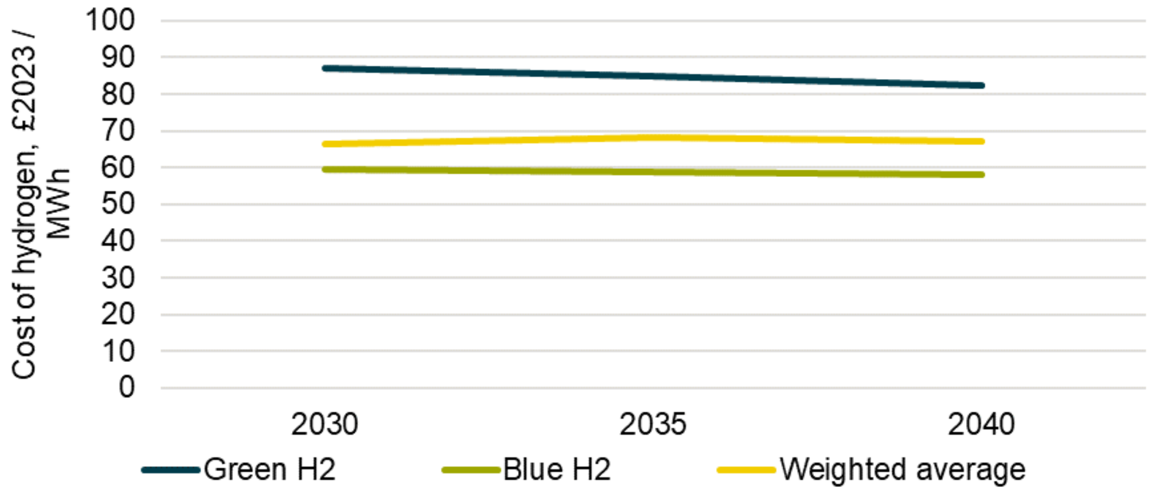
CAPEX makes up a significant share of costs for the following measures: repurposing networks for H2, advanced leakage management, hybrid heat pumps and gas as district heating back-up. As such, the estimated cost-effectiveness of these measures is likely to be sensitive to changes in the above assumptions.

*The Assessment Methodologies approach involved comparing different Net Zero compliant options against multiple criteria, including core CBA elements and wider criteria. It was developed in conjunction with the gas networks, and secured buy-in from DESNZ and Ofgem.

For some measures, results are sensitive to our projected hydrogen costs

- The cost of H2 supply (from a societal perspective) is an input assumption for our cost of energy supply for industrial and power customers, as well as the cost of H2 blended into the network
- We have calculated a **weighted average** cost of **baseload** H2 supply, based on:
    - Frontier calculations of electrolytic / blue H2 production levelised costs of H2, based on DESNZ Hydrogen production cost projections and updated energy supply costs; and
    - assumed shares of green / blue H2 (based on FES 2024 Hydrogen Evolution)
- For blue H2, we calculate costs of ATR + CCS (300MW size)
- For green H2, to proxy for flexible electrolysis operation, costs are based on PEM Electrolysis operating at offshore wind load factors (with electricity costs based on offshore wind LCOE). We have made an allowance for underground H2 storage costs based on Element Energy 2018

Levelised cost of hydrogen projections* under central assumptions by technology, 2030-2040



*Source: Frontier Economics based on DESNZ Hydrogen Production costs and central energy costs for use in appraisal.

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