The Value of Blending in the Nascent UK Hydrogen Economy

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Executive Summary

The key potential benefits of hydrogen blending are identified as follows:

- **Stimulate Demand** - Hydrogen blending breaks the historical 'chicken and egg' between hydrogen supply and demand, by enabling the existing energy system to unlock hydrogen demand and support production.
- **Promote Investment** - Blending makes projects more investible as hydrogen producers are looking for ways to de-risk off-taker demand.
- **Meet Carbon Budgets** - Material environmental benefits are possible without significant hassle or disruption to contribute to achieving the 5^{th} and 6^{th} carbon budgets.
- **Optimise Production** - The gas network is able to store large quantities of energy and can act as a flexible offtaker to balance hydrogen production with demand, enabling production to be ran at optimum load factors.
- **Provide Power Demand Flexibility** - Blending can reduce excess renewable electricity being curtailed and could provide one of the lowest cost use cases of hydrogen.
- **Build Social Acceptance** - Hydrogen blending can act as a strategic test case of social acceptance and market frameworks, enabling evidence to be gathered to better inform the 2026 strategic decision on hydrogen heating.
- **Maintain Safety** – All the evidence collated across trials demonstrates the safety of hydrogen blending.

These benefits were assessed relative to the main counterfactual options for hydrogen producers in the nascent UK hydrogen economy, namely 'do nothing' and storage. A summary of the relative impact level (negative/none, minor, major) is provided in the table below using red, amber, green (RAG) for the major benefits.

Metric \ Option	Do Nothing	Storage	Blending
Market making			
Levelised cost			
Social value			

It is the finding of this paper that hydrogen blending offers a multitude of benefits to the nascent UK hydrogen economy. It can provide the lowest cost means to manage demand risk during the early years of the hydrogen ecosystem, with the potential to create up to a 60 TWh pa national market for low carbon hydrogen based on 2025 gas demand, in a non-disruptive manner to existing users.

Alongside these market-making benefits, hydrogen blending also achieves significant carbon savings, with the potential to generate over £2.7 billlion pa of social value in reduced emissions, and make a material contribution to achieving the UK's carbon budgets. Finally, a wide range of unique strategic benefits result from hydrogen blending, such as increasing societal awareness and acceptance of hydrogen in the home, as well as providing a critically flexible use-case for hydrogen to manage any conversion process to 100% hydrogen.

The findings of this paper support the position that blending should be made available to producers as a viable option to manage demand risk, alongside the other options described in the Hydrogen Transportation and Storage Consultation, with financial support provided through the Hydrogen Business Model. Each production facility will have its own unique set of circumstances which will make blending more or less suitable than the other options, and project developers should therefore be free to choose blending as a means to manage demand volatility.

Beyond the benefits associated with being an off-taker of last resort, blending also provides a means to decarbonise the gas grid and reduce the cost to consumers for curtailment payments. Electrolysers using electricity that otherwise would have been curtailed, due to electricity grid constraints or periods of excess electricity generation, can produce low-cost hydrogen for blending into the gas grid with a potentially even more favourable carbon cost effectiveness than biomethane which is already being financially supported by Government under the Green Gas Support Scheme.

Introduction

The blending of hydrogen up to 20 vol% within natural gas supplies has been identified as an early enabler of the hydrogen economy by the Department for Business, Energy and Industrial Strategy (BEIS), detailed within the UK Hydrogen Strategy[1]. A policy development process has been committed to, whereby a policy decision is to be taken in 2023 to potentially sanction the blending of hydrogen within natural gas supplies, subject to a positive safety and economic assessment.

This paper provides evidence to support the options assessment and value for money (VfM) case that BEIS are undertaking. The decision under consideration is understood to principally be related to sanctioning blending for the gas distribution network. However, the benefits outlined within this paper have been evaluated for both the distribution network and transmission system in order to show the true magnitude of the benefits that could be realised. As highlighted to BEIS before, we believe the case for blending in the transmission network should be assessed and run concurrently with the distribution network.

Alongside detailing the benefits of blending to the hydrogen economy, an assessment of the value for money relative to other options available to producers has been undertaken.

The boundary of the economic assessment has been drawn such that enabling components that do not necessitate costs to facilitate blending deployment, have been excluded from the economic evaluation. Such components, and their justification for inclusion or exclusion within the economic assessment is detailed within this study.

Further to the above assessments, this paper provides an assessment of evidence for a number of 'known unknowns' that were identified by BEIS team as part of their implementation options appraisal process.

[1] BEIS, *UK Hydrogen Strategy*, 2021

Method

In order to complete a value for money assessment for blending, the counterfactual options available to hydrogen producers (and Government) must be identified and assessed. At this stage it must be noted that the options available, and therefore the resultant benefits, are not universal and depend on the strategic role that is being investigated. As such, the identification of counterfactual options and assessment of the benefits must be carefully considered for each combination.

It is known that BEIS are considering the primary strategic objectives for blending implementation options to be:

- Ability to accelerate growth in the hydrogen economy by providing a route to market for volumes of hydrogen.
- Ability to manage the impact of blending on the supply of hydrogen to alternative end uses.

This paper provides an assessment of the relative benefits of blending for not only these objectives, but also other objectives which are shown to be of significant benefit to the UK during the early stages of the hydrogen economy development.

Counterfactual Options

The main counterfactuals identified for blending are:

1. The 'Do nothing' option (status quo). In this option, no additional transport or storage infrastructure is required, rather producers operate 'flexibly', adjusting production levels to respond to changes in demand. This may entail features such as modular design, allowing 'units' to be switched on and off as required, or ramping down production when offtakers are offline, unavailable or no longer willing/able to use hydrogen.

2. Use transport and storage infrastructure to store volumes of produced hydrogen which would otherwise go unused at the time of production. Due to technical and commercial issues in the near term this would be limited to small scale pressurized storage tanks and point-to-point pipelines, while in the longer term this would be achieved in geological features such as salt caverns and depleted gas reservoirs connected via a more complex network of pipelines.

Further details on the counterfactual options are described in the following benefits and value assessment sections.

Benefits Identification and Value Assessment Criteria

The benefits for blending can be divided into three broad categories:

1. **Supply side –** these capture the benefits of hydrogen blending to the supply side of the hydrogen economy.
2. **Demand side -** these capture the benefits of hydrogen blending to the demand side of the hydrogen economy.
3. **Strategic –** these capture the wider strategic benefits of hydrogen blending to the hydrogen economy.

This paper evaluates the benefits of blending, relative to the identified counterfactual options, against the following range of quantitative and qualitative criteria:

- Market making – the relative level of hydrogen supply/demand that can be achieved (GW)

- Carbon abatement – the absolute abatement achieved ($MtCO_{2e}$) and resultant economic social benefit (£) attributable to the abated carbon
- Demand risk management – cost implication of loss of off-taker (£/MWh)
- Curtailment alleviation – cost implication and carbon abatement from hydrogen produced with curtailed electricity ('carbon cost effectiveness')
- Geographical diversity – the level of dispersed production achievable
- Socialisation – the level of social acceptance achievable
- Hydrogen conversion – ability to reduce barriers to network conversion
- Export markets - ability to leverage such a market to export technologies, skills and know-how to international markets.

Benefits Identification and Value Assessment

A variety of demand side, supply side and wider strategic benefits have been identified and which are detailed, in no particular order, and assessed in the following sections.

Supply side benefits

Demand risk management

The initial development of the hydrogen economy will be anchored in the production of low-carbon hydrogen for use primarily in industry, power, and transport. This model relies upon a point-to-point distribution system of hydrogen from production to specific sites, where bilateral agreements will be required between the producer and user - creating microgrids of hydrogen production-distribution-use. By their nature, the resilience of such microgrids will rely heavily on a handful of industrial sites. This reliance upon a small group of large users creates a demand risk for producers, which manifests in two forms:

a) Delayed hydrogen adoption from industrial sites, resulting in slower demand growth than expected.
b) Reduced demand from planned activities (maintenance periods) or spontaneous activities (unplanned shutdowns).

Therefore, demand-risk exists for producers and will need to be appropriately mitigated to provide the certainty needed to facilitate FID on production sites. Such mitigation could come in three forms:

a) 'Do nothing' with commercial/legal guarantees e.g., take-or-pay agreements, third party insurance, government-backed insurance via the hydrogen business model (HBM), *etc*.
b) Blending surplus hydrogen into the natural gas network.
c) Storing surplus hydrogen in dedicated hydrogen storage facilities.

From the producer's perspective, the simplest solution would be a financial solution via the HBM, where the risk is transferred to treasury and a payment of some sort is made to producers when they are curtailed due to lack of demand. This is conceptually similar to the curtailment payment made available to renewable electricity generators when they are unable to discharge power due to downstream constraints. Although commercially expedient, this solution is likely to be suboptimal, as it serves to increase the support intensity (£/MWh) given that this regime translates to suboptimal use of production assets.

All other forms of commercial guarantee are essentially insurance policies, where the commercial risk would be transferred to another party in exchange for a premium. Any additional insurance premiums would then be embodied within the production costs of the hydrogen. Given that the HBM provides the revenue support mechanism that bridges the gap between the hydrogen strike price and the actual cost of production, any insurance-based solution would ultimately manifest as additional support. Therefore, it can be seen that all solutions that mitigate this demand risk via a commercial guarantee would lead to an increase in support intensity (£/MWh). Alongside an increase in support intensity, commercial-based solutions would forgo the economic and wider benefits that would result from consumption of the marginal hydrogen production.

A physical solution that enables production levels to be maintained whilst managing this demand-risk is therefore likely to be preferable, and would ensure that the economic benefits of the marginal hydrogen consumption are secured/realised. Such physical solutions would either be through storage or blending into the natural gas network.

As has been noted previously, the current large scale storage development timeline resulting from the hydrogen transport and storage business model will mean FID on the 10 GW of production needed by 2030 will likely need to be taken in absence of large scale storage being available. Therefore, in the interim period, small scale storage (e.g. bullets, pressurised tanks) and blending provide the only physical means to mitigate the demand-risk within hydrogen microgrids. This provides a strong justification for the sanctioning of hydrogen blending, and for unlocking the current embargo within the HBM to avoid the need for the HBM to absorb the demand-risk via commercial solutions.

An assessment of the marginal costs of flexible production, storage (large and small scale) and blending has been undertaken to understand the comparative costs of managing the demand risk outlined above. The exact level of demand risk any producer will need to manage will be project specific, therefore a basis has been taken for the purpose of comparison, this basis assumes:

a) 100 MW of peak hydrogen flow must be catered for - this is the order of magnitude of a large industrial site tripping and their hydrogen supply needing to be diverted.
b) Such a magnitude of flow would need to be managed in total for one month each year.

The impact of producers having to reduce output has been assessed by comparing the levelised cost of hydrogen production (LCOH) operating at full load, under reduced operating hours. This has then been compared with the increase in LCOH when taking into account the costs of blending. This assessment does not consider losses in efficiency that producers may experience when altering hydrogen output, which is a conservative position when assessing the benefits of blending. However, this does highlight that a reduction in operating hours increases the LCOH as the capital and fixed operational costs have to be spread over a smaller volume of hydrogen output. The assessment also does not include costs to transport the hydrogen from the production to blending location. This will vary significantly between production projects so should be assessed on a case-by-case basis.

The analysis also explores the lost carbon abatement that occurs as a result of CCUS-enabled producers ramping down production in a situation when an offtake goes offline. The potential carbon abatement that would be lost from an electrolytic production facility going offline is more difficult to quantify as the production situation is more variable. If the input electricity source is connected to the electricity grid there could be potential to export the energy as electricity, in which case there would be no loss in carbon saving from the hydrogen producer ramping down production. However, there are other scenarios in which the electricity generation is not grid connected or the electricity grid is constrained where there would be a lost carbon saving from the hydrogen producer reducing production. Due to the variability in lost carbon abatement, its impact from an electrolytic producer ramping down has not been quantified or valued.

This methodology uses the central values for PEM Electrolysis and ATR+GHR with CCUS 300 MW commissioned in 2025 from BEIS Hydrogen Production Costs 2021 in estimating the increase in LCOH. The production capacities for both production routes are assumed to be 100 MW and it is assumed that they have one offtaker that becomes unable to take hydrogen for one month of the year for the first ten years of the production project. Similar results are expected for larger production projects that have a 100 MW offtake go offline, although the analysis on the impact on LCOH below would only apply to 100 MW of the production that the risk is managed for and not the remaining production capacity which would have the full load LCOH.

Table 1: Estimated impact of ramping down hydrogen production and blending on levelised cost of CCUS-enabled hydrogen (£/MWh)

LCOH component (£/MWh)	CCUS Enabled		
	Full Operation	Ramp Down	Blending
Capex			
Hydrogen production	11.84	12.47	11.84
Blending	-	-	0.04
Opex			
Fixed OPEX	3.24	3.42	3.24
Variable OPEX	0.14	0.14	0.14
Electricity cost	3.79	3.79	3.79
Natural gas	24.56	24.56	24.56
CO_2 T&S cost	5.40	5.40	5.40
Carbon cost	0.88	0.88	0.88
Blending	-	-	0.02
Total LCOH	49.86	50.67	49.93
Social value of lost carbon abatement	-	3.30	-
% increase in cost for 10 years of demand side risk management		1.6%	0.1%

Table 2: Estimated impact of ramping down hydrogen production and blending on levelised cost of electrolytic hydrogen (£/MWh)

LCOH component (£/MWh)	Electrolytic Production		
	Full Operation	Ramp Down	Blending
Capex			
Hydrogen production	19.13	20.11	19.13
Blending	-	-	0.25
Opex			
Fixed OPEX	7.77	8.22	7.77

LCOH component (£/MWh)	Electrolytic Production		
Variable OPEX	3.48	3.48	3.48
Electricity cost	81.42	81.42	81.42
Blending	-	-	0.15
Total LCOH	111.80	113.23	112.20
% increase in cost for 10 years of demand side risk management		1.3%	0.4%

The total impact of either blending or ramping down hydrogen production on the LCOH was found to be minor under the assumptions made. However, the aggregate cost increases more significantly under the ramping down production for the CCUS-enabled scenario when considering the social value of lost carbon abatement at £3.30/MWh for the first ten-year period.

It should be noted that the change in levelised cost of hydrogen production from demand side risk management is not directly comparable to the calculated levelised costs of demand side risk management below. This is due to the change in LCOH being spread over all hydrogen volumes produced while the levelised costs of demand side risk management are only apportioned over the hydrogen volumes that use the physical solution e.g. the volumes of hydrogen that are blended.

Small scale above ground storage (pressurised tanks) has been discounted as a means to manage demand risk on the grounds of capacity and cost. Pressurised tanks cost in the order of 5 times as much as salt caverns (on a £/MWh basis) with a typical vessel able to store less than 300kg (< 12MWh). The upper tier COMAH limit is 5 tonnes which would give one days' worth of storage for a 10MW electrolyser. Therefore, above ground storage is not considered to be a credible alternative to blending or underground storage for demand risk management.

The large scale storage technology has been taken to be salt caverns, with economic figures taken from the 2018 Element Energy report[2] for BEIS on hydrogen storage costs. A table of cost figures for salt caverns is given in the report, the average costs have been used to make the analysis more representative of a national profile. The input figures used are given in Table 3.

Table 3: Salt cavern economic inputs

Sizing Data		Notes
Peak charge flow (MW)	100	Instantaneous charge rate from distressed hydrogen source
Peak discharge flow (MW)	100	Instantaneous discharge rate from store

2 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

Sizing Data		Notes
Hours of charging (hours pa)	730	Hours each year when charging is needed
Total capacity (GWh)	73	Total storage needs
CAPEX		
Cavern capacity (£thousand/GWh)	1,674	Cost of the cavern itself
Discharge capacity (£thousand/MW)	25.6	Cost of the discharge equipment from the cavern
OPEX		
Cavern capacity (fixed) (£thousand/GWh)	79	Fixed costs of operating a cavern
Discharge capacity (fixed) (£thousand/MW)	1.42	Fixed costs of operating discharge equipment
Variable costs of storage (£thousand/GWh)	0.48	Total variable costs for each GWh processed (stored and discharged)

Assuming a 30 year economic lifetime, and a discount rate of 5%, a levelised cost calculation was performed. It was assumed that the storage was cycled three times in a year to reflect the fact that salt cavern storage would be used for other purposes, giving an annual utilisation of 50%. Given the uncertainty over the quantity of demand risk i.e., charge rate and charging hours, a number of sensitivities were performed - each input parameter was doubled and halved in isolation to understand how sensitive the levelised cost of demand risk management via storage was to demand risk variation. The results are given in Table 4.

Table 4: Levelised cost of demand risk management via salt cavern storage

Sensitivity	Levelised cost (£/MWh)
Base case	33
Charge rate doubled (200 MW)	32
Charge rate halved (50 MW)	35
Discharge rate doubled (200 MW)	32
Discharge rate halved (50 MW)	35

The levelised costs of demand risk management via salt cavern storage were found to be in the range £32-35/MWh, with a base case of £33/MWh. Most of this cost is attributable to the capital items, where CAPEX constituted 57% of the levelised cost, and OPEX the remaining 43%.

A comparative analysis was conducted, using the same base case and sensitivities, to assess the levelised costs of demand risk management via hydrogen grid entry unit technologies to allow for hydrogen blending to act as the demand-risk management solution. The gas networks, through the ENA's Gas Goes Green programme, are developing a functional specification for hydrogen blending facilities which has provided indicative blending facility costs. Those costs only considered CAPEX, therefore OPEX expectations were derived from biomethane grid entry units given that both forms of grid entry unit perform similar functions of pressure/flow control with gas quality measurement. The annual OPEX of a typical biomethane grid entry unit was found to be 10% of CAPEX. Table 5 provides the hydrogen grid entry unit economic inputs.

Table 5: Hydrogen grid entry unit economic inputs

Sizing Data		Notes
Peak flow (MW)	100	Instantaneous rate from distressed hydrogen source
CAPEX		
Design (£thousand/MW)	1.98	Project delivery, CDM and design
Equipment (£thousand/MW)	5.26	Supply, manufacture and testing
Site preparations (£thousand/MW)	2.30	Civil and mechanical site readiness
Install & commission (£thousand/MW)	0.73	Delivery, installation and commissioning
OPEX		
Total OPEX (£thousand/MW)	1.03	Calibration bottles, odourant, general maintenance and certifications (10% of CAPEX)

A 10 year asset lifetime and 5% discount rate was used to assess the levelised cost of demand-risk management via blending. Two sensitivities were undertaken, doubling and halving the peak flow, to understand how sensitive the levelised cost was to this variable. The results are given in Table 6.

Table 6: Levelised cost of demand risk management via hydrogen blending

Sensitivity	Levelised cost (£/MWh)
Base case	2.8
Peak rate doubled (200 MW)	2.1
Peak rate halved (50 MW)	3.7

The levelised cost of demand risk management via hydrogen blending was found to be between £2.1-3.7/MWh, with a base case of £2.8/MWh. Blending was therefore found to be an extremely cost-effective form of demand risk management, compared to a counterfactual of marginal storage via salt caverns, where the comparative cost of blending was found to be an order of magnitude below that of large scale storage.

The reasoning for the identified cost disparity is due to the nature of the equipment involved:

a) The sizing and cost of a storage facility to manage a given demand risk is proportionate to the multiple of, the expected distressed flow, and the duration of time the flow is expected for, e.g., 'flow x time'.
b) Whereas the sizing and cost of a grid entry unit is driven only by the magnitude of the flow, the duration of flow makes little difference given that the operating costs are mostly fixed.
c) This is compounded by the nature of salt cavern storage, which requires separate discharge processing equipment to remove any contaminants from the storage facility and condition the gas for re-injection.

Given the uncertainty over the nature of the demand risk that must be managed in any location (flow and duration), blending offers a comparative advantage over storage because the costs of blending are largely related to only the flow rate component of the demand risk, instead of both the flow rate and duration. Therefore, blending offers a lower technical risk due to its reduced reliance on uncertain parameters. It should be noted however that storage offers a unique advantage, in that storage creates dispatchable hydrogen that is in the control of the operator. This additional functionality is not relevant to a demand risk management comparison, but is a valuable feature of storage when considering how to balance a hydrogen system over an annual demand cycle.

It should also be noted that the underpinning studies used to make this comparative assessment are both high-level techno-economic assessments, therefore the 'real' figures will likely differ somewhat. However, given the order of magnitude difference in calculated levelised costs of demand risk management, it can be reasonably concluded that blending offers a more cost effective means by which to manage demand risk than large scale storage when it becomes available.

Curtailment alleviation

The UK Government is committed to decarbonising electricity by 2035. This will require significantly more renewable electricity generation to be installed in the UK.

Curtailment happens when renewable electricity generators such as wind and solar are asked to switch off by the Electricity System Operator (ESO) as a result of constraints in the transmission system and a lack of long-duration storage capacity. Curtailed electricity is likely to increase as the proportion of renewables in the generation mix increases. A paper[3] released by Edinburgh University estimates that wind production alone could result in 7.72 TWh of curtailed generation by 2030.

Given that generators are typically paid to turn down as they need to recover their lost support payments, curtailment results in a net cost to the ESO which is ultimately passed on to the consumer. An independent report[4] published by LCP in 2022, found that in 2020 - 2021 curtailing wind power added £806m to energy bills in Britain.

The above report also highlights that the majority of 'turn up' actions made to replace the curtailed wind are currently provided by CCGTs (i.e., gas generation), which represent the dominant source of

[3] https://www.sciencedirect.com/science/article/abs/pii/S0360319921017481
[4] https://www.drax.com/wp-content/uploads/2022/06/Drax-LCP-Renewable-curtailment-report-1.pdf

flexible generation in the current system. This means that in addition to the consumer costs, zero-carbon wind generation is being replaced with unabated fossil fuel generation, increasing CO_2 emissions (2% of total power sector CO_2 emissions are due to this curtailment).

Blending electrolytic hydrogen into the grid will be a strong facilitator to reduce curtailment as the gas network can absorb variable production rates of hydrogen from electricity. It could potentially deliver amongst the lowest levelised cost of hydrogen, as it enables electrolysers to access the cheapest electricity and could avoid the need for storage at the hydrogen production site. This is key to support decentralised net zero hydrogen production which may not be otherwise viable.

In their Sixth Carbon Budget Report[5] (2020), the Climate Change Committee has included projections of curtailed electricity used for hydrogen production up to 2035 within all of their scenarios (see Figure 1 below). The latest National Grid Future Energy Scenarios[6] also reveals a significant opportunity for production of hydrogen via electrolysis to help integrate renewable electricity generation and reduce curtailment, as seen by the large levels of curtailment across all four scenarios (Figure 2 below).

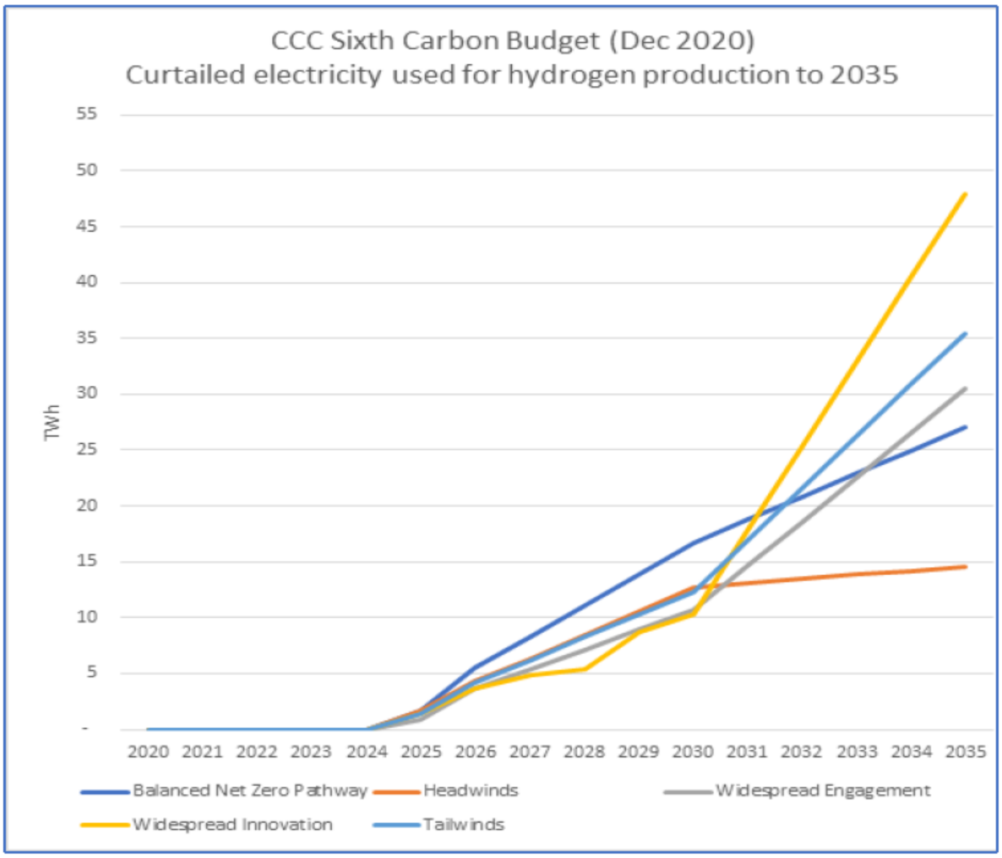

Figure 1: CCC Sixth Carbon Budget Report under different CCC scenarios

[5] https://www.theccc.org.uk/publication/sixth-carbon-budget/
[6] https://www.nationalgrideso.com/document/263951/download

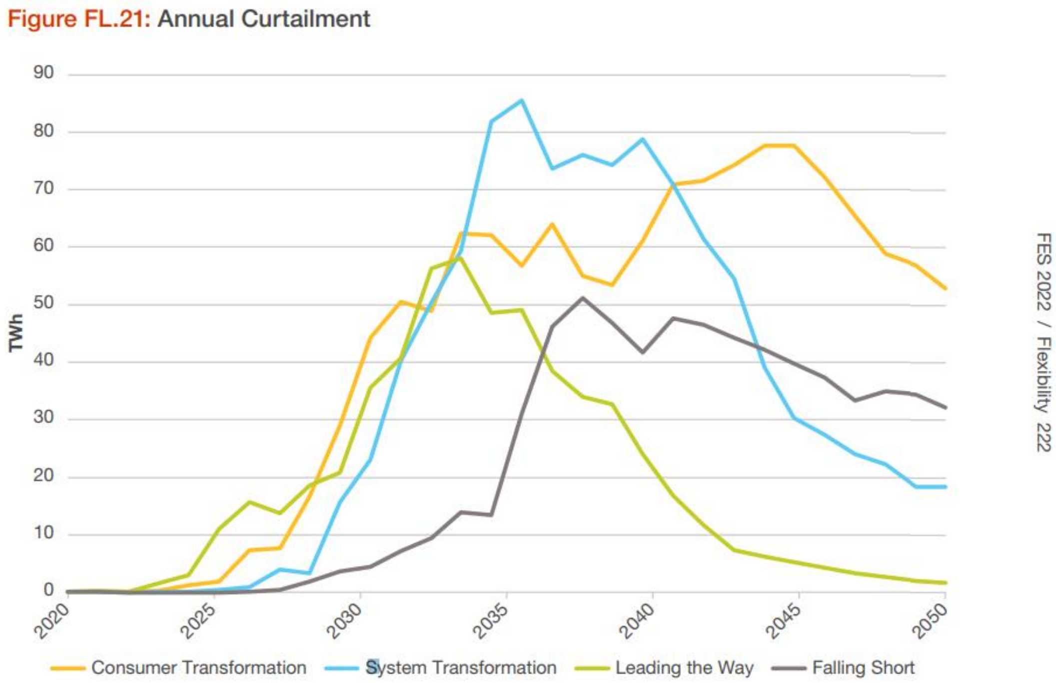

Figure 2: Annual curtailment up to 2050 under different FES 2022 scenarios

We have identified an opportunity in excess of £19.0 billion that could be saved on curtailed electricity payments by 2036 where hydrogen is produced from electricity that would otherwise be curtailed. In the short to medium term, hydrogen produced from curtailed electricity using the spare capacity of existing electrolysers could be blended into the gas grid, without the need for storage infrastructure, effectively as an off-taker of last resort until other off-takers come online. We have calculated that the carbon cost effectiveness of such an approach could be better value than the existing biomethane support package.

If a more flexible approach to blending were taken, and dedicated electrolysers were installed to produce hydrogen from curtailed electricity and that hydrogen was to be blended into the gas grid, by 2036 a cumulative total of 185 TWh of hydrogen could be blended in the gas grid. This would displace the equivalent of 15.4 TWh/annum of fossil gas, avoiding 33.9 million tonnes of CO_2 emissions. However, as noted previously, delivering such a level of blending across the networks would require access to large scale storage infrastructure to manage diurnal and seasonal fluctuations in gas demand.

To calculate the above indicative figures, we have used the CCC's Sixth Budget Report projections on avoided curtailed electricity used to produce hydrogen under the CCC's *Balanced Net Zero Pathway* scenario and a cost of £74/MWh of electricity curtailed, based on the numbers published by Imperial College[7].

Our detailed calculations and assumptions are shown in the Excel file excerpts provided in Annex B.

[7] https://reports.electricinsights.co.uk/q4-2020/record-wind-output-and-curtailment/

Note that the above cost estimates do not include the cost savings resulting from avoided cost of storage on the production site to deal with variable production and misalignment between hydrogen production and demand.

Value for money of different support rates for electrolytic hydrogen blending to reduce curtailment

The Impact Assessment[8] undertaken by BEIS to support the development of the Green Gas Support Scheme concludes that they should continue to support biomethane injection into the gas grid by a tiered tariff paid on a p/kWh basis for all eligible units injected into the gas grid for 15-years from first injection, as this provides the best value for money.

The Carbon Cost Effectiveness (CCE) of supporting the decarbonisation of the gas grid via a tiered tariff for biomethane as outlined above is £173/tCO_2, which represents the social cost per tonne of carbon abated. Policies with a lower or negative number are generally thought to be better value for money.

Taking this as the target carbon effectiveness of supporting the decarbonisation of the gas grid, we have estimated under two different scenarios what would be the cost of supporting hydrogen blending into the gas grid and the associated CCE. Two scenarios are outlined below:

a) Scenario 1: this calculates the cost required to support blending of hydrogen that has been produced from electricity bought at a cost including commodity costs only (i.e. wholesale price without green levies and network charges).

b) Scenario 2: this calculates the cost required to support blending of hydrogen that has been produced from renewable electricity at the Solar/Wind Marginal Cost of Production (estimated at £45/MWh, taken from latest CfD auction prices[9]).

In both scenarios, hydrogen is produced using electrolysers already producing hydrogen for contracted offtakers, using spare production capacity which exists due to, for example, mismatch between off-the-shelf electrolyser capacity and actual contracted demand. The CAPEX and fixed OPEX components of the electrolyser are therefore not included in the calculation; however a cost for transportation of hydrogen to a suitable blending injection point has been included to represent the marginal benefit versus the 'do nothing' approach.

For this assessment, the transportation cost was set at £5/MWh as an indicative cost for early, small scale projects that require a short pipeline. It should be remembered that the objective of this assessment is not to define the absolute value for all scenarios, rather to show that value for money can be achieved for an indicative scenario. Each project will have its own specific set of requirements for the transportation of hydrogen for blending, and therefore the relative value that will be achieved will depend on a wide range of factors such as distance, pressure, capacity, utilisation, etc.

The detailed financial model can be found in Annex B.

Assuming a policy to support blending from 2025 to 2036 and a total 185 TWh of low carbon hydrogen injected into the grid by 2036, the financial support required and the CCE of the two scenarios is set

[8] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1018133/green-gas-impact-assessment.pdf

[9] https://www.carbonbrief.org/analysis-record-low-price-for-uk-offshore-wind-is-four-times-cheaper-than-gas/

out in the table below. These are based on the cost on the estimated cost and carbon emission savings from using curtailed electricity outlined in the previous section.

Table 7: Carbon cost effectiveness from curtailed generation

Scenario	Support Rate (£/MWh)	Total Support Cost (£ million)	Curtailment Savings (£ million)	Net Cost Total (£ million)	CCE (£/tCO_2e)
1	60.13	11,126	19,072	-7,946	-234
2	49.07	9,080	19,072	-9,992	-294

We can see from the above table that the CCE of supporting hydrogen injection at a rate of £60/MWh under Scenario 1 is significantly below the CCE target for biomethane injection, achieving a negative CCE, whilst allowing electrolysers to access renewable energy that would otherwise be curtailed at the CfD price, results in a lower support rate (£49/MWh) and delivers a much lower (more negative) CCE. This shows that both scenarios deliver value for money significantly better than the policy already in place to support biomethane. It should be noted that the CCE values are 'normalised' per unit of hydrogen produced and are not dependent on the total volume produced; that is, they apply to each unit of hydrogen produced under the relevant conditions and would be achieved from the first projects supported.

In summary, policies to support electrolytic hydrogen blending to reduce curtailment can deliver significant value for money however this is conditional upon the Government exempting electrolytic producers from the non-commodity costs of electricity (Scenario 1) and/or supporting electrolytic producers directly connected to renewable energy generation (Scenario 2).

We have also detailed a scenario where electrolysers are installed specifically to access the curtailed electricity for dedicated production of hydrogen for blending. The assessment shows that even accounting for electrolyser CAPEX and OPEX, the carbon cost effectiveness is more favourable than biomethane support. We acknowledge that this scenario goes beyond the 'offtaker of last resort' strategic objective being considered by BEIS, however it should be noted that a 'flexible offtaker' strategy has the potential to alleviate a significantly larger volume of curtailed electricity and deliver greater benefits sooner. The details can be shared upon request.

Dispersed production

Given the national coverage of the existing natural gas network, it provides a means to connect demand with dispersed production. This enabling function of the natural gas network is demonstrated within the biomethane market. Figure 3.0 provides a map (dated December 2022) of all operational biomethane plants, which shows the extensive coverage that has been achieved across the UK.

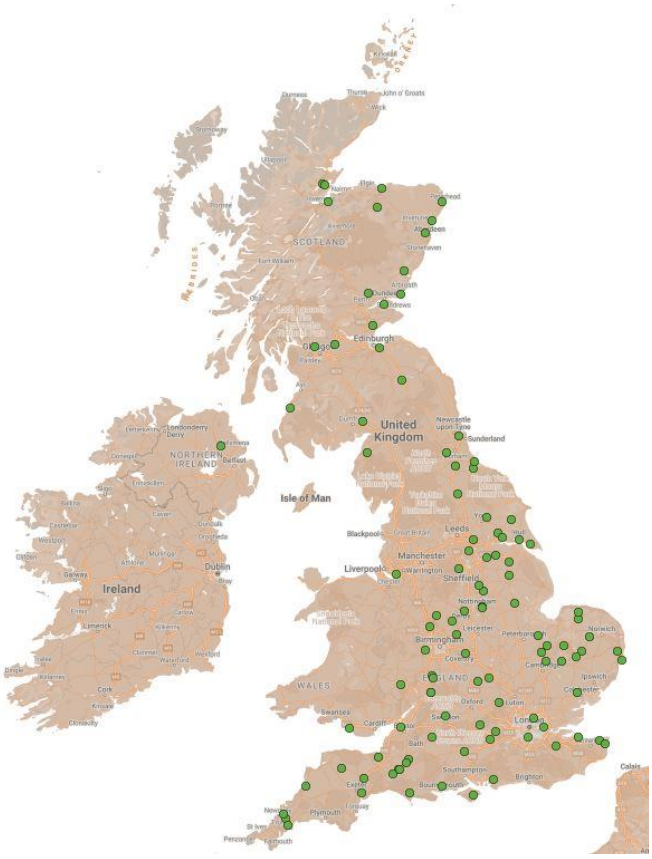

Figure 3: Biomethane production plant locations (Source: NNFCC)

By providing a means of national distribution, hydrogen blending will promote investment in hydrogen production outside of the industrialised regions, where large industrial sites are rare. This is particularly pertinent given the policy aim of delivering over 50% of the 2030 production target via electrolytic production, which therefore requires pairing at least 5 GW of electrolytic production with renewable electricity generation assets. The UK has made substantial progress in developing domestic renewable capacity. In 2021 the onshore wind[10] and solar PV[11] installed capacities were 14.6 GW and 14.0 GW respectively. Much of this capacity lies outside of the industrialised regions of the UK, for example in 2021[12] the East of England and South East had 6.3 GW and 4.4 GW of total installed renewable capacity, representing the second and third highest capacity regions in the UK respectively.

The development of large new renewable generation assets, such as offshore windfarms, ranges between 6 - 11 years[13]; therefore developing at least 5 GW of electrolytic hydrogen production by 2030 will require leveraging the existing renewable asset base. Given that much of this capacity is located outside of the industrialised regions of the UK, hydrogen blending will be a critical enabler to connect supply with demand and support the investment cases for developing electrolytic production at existing renewable generation locations.

[10] Statista, *Cumulative installed capacity of onshore wind in the United Kingdom (UK) from 2009 to 2021*, 2022
[11] Statista, *Cumulative installed capacity of solar photovoltaic in the United Kingdom (UK) from 2009 to 2021*, 2022
[12] BEIS, *Regional renewable electricity in 2021*, 2022
[13] https://windenergyireland.com/images/files/iwea-onshore-wind-farm-report.pdf

Demand side benefits

Market making

The sanctioning of hydrogen blending, up to 20 vol%, within natural gas supplies, would equate to a low carbon energy content of 7% based on the relative calorific values of hydrogen and natural gas. The average annual gas demand[14] over the period 2011-2021 for the UK was 851 TWh, of which around 60% is from the gas distribution network. The Gas Networks along with the Energy Networks Association have recently published[15] an assessment of Great Britain's hydrogen blending opportunity based on forecast demand in 2025 and Table 8 outlines the hydrogen market sizes for the distribution and transmission grids that would result from hydrogen blending at 20 vol%, in both energy terms and equivalent household terms[16].

Table 8: Blended hydrogen market size in 2025 (transmission and distribution)

	Distribution-only	Transmission-only	Total
Hydrogen market (TWh pa)	35	25	60
Household equivalent (million)	3	2	5.0

These figures demonstrate that hydrogen blending can represent a material use case for hydrogen, creating a significant market for early development of hydrogen supply. The hydrogen market figures within Table 8 can be compared with the biomethane market, to provide a basis for assessing scale. In 2021[17] the total amount of biomethane injected into the gas network was 6.5 TWh; therefore, the blending of hydrogen within just the distribution network alone represents a market that is nearly five times the current size of the biomethane injection market, and when transmission is also included more than nine times the size of this market.

The hydrogen demand figures contained within Table 9 can be converted into low carbon hydrogen supply figures, to provide a basis for assessing the level of supply stimulus that hydrogen blending could engender[18].

Table 9: Hydrogen supply capacity for blending based on 2025 blending capacity

	Distribution-only	Transmission-only	Total
Hydrogen production (GW)	5.3	3.8	9.1

[14] BEIS, *DUKES 4.1 Natural gas supply and consumption data*, 2022
[15] ENA, *'Britain's Hydrogen Blending Opportunity'*, 2022
[16] Household equivalent values assumes 12 MWh pa of hydrogen supply per household, which is the Ofgem reported average total gas demand for a UK household.
[17] BEIS, *DUKES 4.2 Natural gas production and supply data*, 2022
[18] Hydrogen production load factor assumed to be 75%, resulting in 6,570 hours of operation per year.

The current Energy Security Bill has led to a doubling of the hydrogen production target from 5 GW to 10 GW by 2030. The blending of hydrogen can play a crucial role in enabling supply investment over the 2020's, given that hydrogen blending within the distribution network alone could support over 50% of the 2030 target and when transmission is included, the target could be nearly met.

The current BEIS timeline for the hydrogen transport and storage business model is to be finalised in 2025, which would likely lead to final investment decisions (FIDs) on hydrogen networks 2026/2027 and operation by 2030 at the earliest. Therefore, the supply investment decisions needed to achieve 10 GW by 2030 will need to take place before the establishment of an extensive hydrogen network.

Without access to a physical option to manage variable demand profiles such as storage or blending, production sites will be required to match their supply with demand on a daily or even hourly basis. This will lead to suboptimal designs where production may be oversized and underutilised, resulting in a higher levelised cost of hydrogen production (requiring higher subsidy intensity via the HBM), or is undersized and misses the opportunity to create markets for demand by having spare production capacity to react to new offtakers coming online. The volume of hydrogen supply in the 'do nothing' scenario will therefore be limited by the demand at the time, which due to a variety of regulatory, commercial and technological risks could slow the pace of hydrogen adoption across sectors.

Hydrogen blending can therefore play a crucial role in enabling early hydrogen production before the creation of extensive hydrogen networks and availability of large scale storage, both of which will be required to connect production to dispersed industrial and power sites.

Carbon abatement

The blending of hydrogen within natural gas supplies will lower the carbon intensity of the gas supplied to consumers, and therefore create abatement value at the point of use. This economic benefit is defined as the social value of greenhouse gas emissions abatement, and represents the overall social value that will accrue to the UK economy by reducing carbon dioxide equivalent emissions. BEIS outline a standardised valuation mechanism to enable the social value of abated carbon dioxide equivalent to be included within policy appraisal processes.

Using the maximum potential hydrogen demand data withinTable 8, the magnitude of carbon abatement can be determined by using BEIS fuel conversion factors[19], where the carbon intensity of direct emissions resulting from natural gas usage is quoted as 0.18 tCO_2/MWh(th). The abated carbon can then be monetised using the BEIS social value figures[20] for carbon abatement, where the 2022 central-case figure is £248/tCO_2. Table 10 outlines the total social value benefit of the hydrogen blending market.

Table 10: Social value of hydrogen blending at maximum capacity in 2025

	Distribution-only	Transmission-only	Total
Hydrogen market (TWh pa)	35	25	60
Carbon abated ($MtCO_2$ pa)	6.3	4.5	10.8

[19] BEIS, *Table 12 Government greenhouse gas conversion factors for company reporting: Methodology paper*, 2021

[20] BEIS, *Valuation of greenhouse gas emissions: for policy appraisal and evaluation*, 2021

	Distribution-only	Transmission-only	Total
Social value (£million pa)	1,562	1,116	2,678

The social value of hydrogen blending represents a significant opportunity, where distribution-only blending could yield more than £1.5 billion pa in social abatement value for the UK economy. This should be considered a theoretical 'ceiling' value where blending at 20 vol% is achieved across the entire distribution network based on 2025 gas demand; such a scenario would be impacted by any decline in gas demand from the 2025 baseline, and the availability of geological storage to balance diurnal and seasonal demand cycles whilst maintaining a constant blend level. However, the carbon abatement benefits are material in the early years of hydrogen production deployment.

The carbon abatement benefits of hydrogen blending manifest themselves not only in economic value, but also in enabling the UK to meet its carbon budgets. In 2021 the UK enshrined in law an updated, and more ambitious, emissions reduction target[21] of 78% (relative to 1990 levels) by 2035. This has been reflected in the sixth carbon budget (2033-2037). Therefore, an acceleration of decarbonisation will be needed over the next decade to achieve this legally binding target. Hydrogen blending offers a significant lever that can achieve material carbon savings over the period leading up to and including the sixth carbon budget, which in turn reduces reliance on disruptive and costly solutions that would need to be deployed otherwise, over the remainder of the current decade.

Emission Trading Scheme (ETS) saving

Another potential feature of blending is Emission Trading Scheme (ETS) saving that specific gas users (e.g. power generation and energy-intensive industries) will achieve by reducing their emissions and therefore reducing the quantity of carbon credits needing to be procured. However, it is noted that this is not a system-wide economic benefit, and is not in addition to the social value of the abated emissions.

Strategic benefits

Socialisation

As a new energy vector, the general public have had little direct experience with hydrogen and therefore have a low level of awareness of its potential role in achieving emission reduction targets. The planned policy decision in 2026 will provide a greater degree of clarity on the specific role hydrogen will play within decarbonised heat, alongside other solutions such as electrification and heat networks. Social science research[22] has shown a positive experience with hydrogen blending leading consumers to be more accepting of a potential 100% hydrogen conversion process. Independent social science research conducted during the recent hydrogen blending trials at Keele University and the town of Winlaton showed that *"Experiencing hydrogen in the home through a 20% blend could help pave the way to greater acceptance of 100% hydrogen."*, where residents of the trials were more receptive to a 100% conversion process following a positive experience with a hydrogen blend. This provides sound evidence that the success of any conversion process to hydrogen will be promoted by consumers having an initial positive experience with a hydrogen blend.

[21] https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
[22] Keele University, *Consumer perceptions of blended hydrogen in the home: Learning from HyDeploy*, 2022

Hydrogen conversion

Once the degree of conversion to hydrogen heating is known, focus will turn to the practical implementation of the conversion process. The process of converting a given region from a natural gas-based supply to a hydrogen supply will require instantaneous hydrogen availability, upon the day of conversion. Therefore, to enable significant quantities of hydrogen to be diverted to a specific region, a fully flexible demand of hydrogen would be required to absorb the supply until the day of conversion. Direct use cases of hydrogen, in industry, power and transport are going to have low levels of flexibility in their capacity to forgo their allocated supply, especially if sites have invested to enable them to safely operate with high concentrations of hydrogen. Conversely hydrogen blending is a flexible use case of hydrogen, as it is predicated on the re-use of existing gas installations. This inherent flexibility, and scale (Table 8), means hydrogen blending offers a unique strategic benefit to conversion. Blending would be able to absorb significant quantities of hydrogen supply over the required time period to demonstrate resilience, to then enable such supply to be leveraged within a regionally-specific conversion process.

Export markets

The primary benefits of hydrogen blending are in facilitating the deployment and growth of the hydrogen economy, through creating supply investment stimulus and demand-risk management. These benefits will promote the establishment of a buoyant hydrogen economy within the UK, and in doing so will promote the ability to leverage such a market to export technologies, skills and know-how to international markets seeking to develop their own hydrogen supply chain. There is much international attention being directed to hydrogen, with large support packages being made available across the EU, Asia and Americas as regions compete to establish a dominant role in the global low carbon hydrogen economy. These international competitors have developed their own hydrogen blending ambitions[23] to promote market development and supply chain capacity. Therefore, sanctioning blending ahead of international competitors would enable the UK to capture the market-enabling potential of hydrogen blending and maintain its competitive advantage on the international stage.

Value-for-money boundary

Network capacity

A recent study[24] conducted by the Energy Networks Association (ENA) working in collaboration with the UK gas network operators, has concluded there is substantial hydraulic capacity within the gas network to support the transportation of hydrogen blends without changes to the existing network. A total capacity of 60 TWh pa in 2025 of hydrogen across both the distribution and transmission networks was determined, 35 TWh pa of which is within the distribution network alone. These findings demonstrate the capacity of the existing network to distribute the necessary volumes of blended hydrogen to unlock the supply stimulus outlined in previous sections. This study evidenced that existing network capacity is not a constraint to the deployment of hydrogen blends, and therefore no capacity upgrading costs have been accounted for within the VfM boundary.

[23] International Energy Association, *The future of hydrogen: seizing today's opportunities*, 2019
[24] ENA, *'Britain's Hydrogen Blending Opportunity'*, 2022

System suitability

The HyDeploy project has developed robust evidence to demonstrate the suitability of the existing gas distribution network and associated end users to accepting a hydrogen blend. This evidence has been demonstrated across domestic, commercial and a wide range of industrial sites, supported by six successful trials. Across both the gas distribution network and end users, the HyDeploy programme has not identified any major impacts of introducing a hydrogen blend of up to 20 vol% in the existing system. All the evidence that supported the domestic trials - which was reviewed and approved by the Health & Safety Executive (HSE) as part of the two Gas Safety (Management) Regulations (GS(M)R) exemption processes - is available within the IGEM Hydrogen Knowledge Centre[25]. The HyDeploy programme has generated robust evidence on the suitability of the existing gas distribution network and end users to accept a hydrogen blend, therefore no upgrading costs or de-blending costs have been accounted for within the VfM boundary as they have been deemed to be unnecessary by the available evidence. A similar set of trials would need to be conducted for the transmission system to prove the suitability of pipelines, ancillaries and connected off-taker equipment.

Billing

Hydrogen blending can commence while maintaining compliance with the Gas (Calculation of Thermal Energy) Regulations (G(CoTE)R). Analysis has shown that significant blending capacity is available at higher flow locations such as the local and national transmission systems. In the short to medium term, billing reform will not be available or required to support building blending volumes at material levels. Blending can be managed within the existing Flow Weighted Average Calorific Value (FWACV) regime. Future reform should be weighed on its own merits in how it could support increasing hydrogen blending volumes, biomethane or build resilience for future changes of gas supply, including the potential for 100% hydrogen. Billing reform is not a pre-requisite for hydrogen blending, and therefore, no upgrade costs to the billing methodology for gas have been accounted for within the VfM boundary.

Summary

Hydrogen blending offers a multitude of benefits to the UK hydrogen economy. It provides the lowest cost means to manage demand risk during the early years of the hydrogen ecosystem, with the ability to create a 60 TWh pa national market for low carbon hydrogen, in a non-disruptive manner to existing users. This material market will stimulate hydrogen supply across the country. Alongside these market-making benefits, hydrogen blending also achieves significant carbon savings, with the potential to generate over £2.7 billlion pa of social value in reduced emissions, and make a material contribution to achieving the UK's carbon budgets. Finally, a wide range of unique strategic benefits result from hydrogen blending, such as increasing societal awareness and acceptance of hydrogen in the home, as well as providing a critically flexible use-case for hydrogen to manage any conversion process to 100% hydrogen.

Hydrogen blending can deliver the following benefits:

a. **Stimulate Demand** - Hydrogen blending breaks the historical 'chicken and egg' between hydrogen supply and demand, by enabling the existing energy system to unlock hydrogen

[25] https://www.igem.org.uk/hydrogen-knowledge-centre/

demand and support production. Hydrogen blending in the distribution networks alone could support circa. 5 GW of hydrogen production and has the lowest risk profile of off-takers.

b. **Promote Investment** - Blending makes projects more investible as hydrogen producers are looking for ways to de-risk off-taker demand. History has shown that grid access is essential to facilitate production by providing a means to de-risk investment and provide a smooth, predictable return.

c. **Meet Carbon Budgets** - Material environmental benefits are possible without significant hassle or disruption to contribute to achieving the 5th and 6th carbon budgets. 6 $MtCO_2$ pa of carbon savings are possible in the distribution networks, equivalent to removing 2.5 million cars from the road. Without supporting this option and capturing this 'low hanging fruit' within the hardest to abate sector (domestic heating), a greater reliance will transfer to more expensive and disruptive technologies to ensure decarbonisation in line with carbon budget requirements.

d. **Optimise Production** - The gas network is able to store large quantities of energy and can act as flexible offtaker to balance hydrogen production with demand, enabling production to be run at optimum load factors. Blending is likely to be a low-cost alternative to hydrogen storage which is expected to be challenging to deploy at scale in the short to medium term due to business model design not being delivered until 2025 and the lead-time for construction.

e. **Provide Power Demand Flexibility** - Hydrogen from electrolysis will be essential to providing demand side flexibility to a power system with increasing intermittent generation from renewables. Blending can reduce excess renewable electricity being curtailed and could provide one of the lowest levelised costs of hydrogen.

f. **Build Social Acceptance** - Hydrogen blending is a critical proving stage along the hydrogen for heat discovery journey. It acts as a strategic test case of social acceptance and market frameworks, enabling evidence to be gathered to better inform the 2026 strategic decision on hydrogen heating.

g. **Maintain Safety** – All the evidence collated across trials demonstrates the safety of hydrogen blending. In fact, hydrogen blending reduces the risk of CO poisoning; the largest hazard facing domestic consumers from natural gas usage, although it should be noted the baseline natural gas risk is still low.

Key Report Contributors

- Tommy Isaac, Head of Hydrogen Research, Progressive Energy
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Annex A - Evidence Base

Are the networks able to provide enough blending capacity at the right locations to support BEIS strategic view?

Cadent have published a view of locations on their network that could be used as blending hubs and would maximise the capacity to blend into the Local Transmission System (LTS). Cadent, along with the Gas Transporters (GTs) have also developed capacity maps showing the extent of blending capability across the whole LTS and NTS. These show that the UK network could support up to 60TWh of hydrogen blending, with 25TWh of capacity in the NTS and up to 35TWh of capacity in the distribution network. The networks are well geographically distributed and so will support connections of different producer types and sizes all across the country. There are logical market-based mechanisms that will facilitate a connection approach that will support commercial allocation of capacity and avoid arbitrary access to the network.

BEIS have been clear that the decision in 2023 will apply only to LTS blending and will explicitly exclude NTS blending. This is justified on the basis that National Grid Gas Transmission (NGGT) will be continuing to develop the safety evidence into 2024 and beyond. Evidence for the LTS and associated connections is being finalised during Q4-22 to Q2-23 by Cadent Gas and its partners' HyDeploy programme. Industry is pressing for BEIS to recognise the value of hydrogen blending into the NTS as part of the VfM process so that any such projects would qualify for financial subsidy subject to a satisfactory safety case being made when the evidence for the NTS becomes available. Blending into the NTS can be facilitated through site specific exemptions from the HSE, in a similar way that the biomethane sector started. Additionally, there are locations on the NTS network where a 0.1% blend would facilitate modest hydrogen injection into the NTS grid as the flows in these locations are significant. This would safeguard all safety aspects of the GS(M)R requirements.

What are the costs of blending (and how could they be funded)?

As noted, Cadent are supporting this through sharing an outline Cost Benefit Analysis (CBA)with BEIS; further work to produce a functional specification for hydrogen blending infrastructure has provided indicative costs for hydrogen blending facilities. The costs have been used in the analysis within this paper.

Which market player(s) should be responsible for purchasing blended H2 volumes?

Networks could consume blended hydrogen to meet their shrinkage requirements. Shippers can buy and sell (trade) hydrogen to meet their methane energy balancing needs. There should be no tension between different buying options, as all are valid and could be accommodated with minimal regulatory change. Ultimately, the hydrogen blended would be consumed across the gas connections within the blending zone.

BEIS have highlighted a concern that contracts supporting blending offtake could preclude producers from diverting production to prioritised industrial demand as it emerges in the future. We believe this could be addressed through constraining commercial terms to limit sales to short term (day or month ahead), by including interruption terms for blending - such interruption terms have been common place in certain gas supply contracts for decades, or by the volume to be nominated to blending being at the discretion of the producer. These mechanisms can all be accommodated through commercial arrangements and would not necessitate any change in legislation.

BEIS have been clear that producers should actively prioritise offtake by 100% hydrogen users with blending as a 'reserve offtaker'. This could be facilitated by affording blended hydrogen a reduced level of support under the hydrogen business model, incentivising producers to prioritise 100% hydrogen offtake over blending and to divert production from blending when there are new opportunities to supply 100% hydrogen.

Low-carbon gas certificates can play an important role in promoting commercial development for hydrogen. Low carbon certificate programmes have proved effective across both gas and electricity markets for many years. These provide an additional revenue stream for producers, build engagement with low-carbon propositions and drive decarbonisation across a range of industries. With both biomethane and REGOs in electricity, there is recognition that the certificate need not be tied to the consumption of the specific units of energy that they are associated with. This same approach should be applied to hydrogen, including hydrogen for blending.

In the absence of tradeable value from low carbon certificates there would still be demand from networks to facilitate blending. Blending facilitates consumer engagement with hydrogen which will play a critical role in the long term viability of the gas network and so early engagement is important and valuable. Regardless of certificate benefits, hydrogen blending would have a real and measurable effect on networks' scope one emissions and so contributes directly to a core element of ESG strategy.

Shippers would also seek to facilitate blending, regardless of certificate revenues. Shippers build value through origination of commercial relationships and physical flows. Adding producer relationships for blending would act as means of building commercial propositions to drive mutual value between producers and shippers, as well as securing relationships that have the potential to evolve and drive growth as markets and investment portfolios evolve. This has been observed in biomethane markets where initially shipper services were coordinated through a single contract shipper, this has evolved as shippers have sought to build commercial relationships with biomethane producers and develop related services. Shippers play a crucial role in driving innovation in commodity markets and should be encouraged to participate in blending.

Whether/how gas billing should be modified to account for blending?

Hydrogen has a lower energy content (calorific value, or CV) than methane. Under the current billing regime, which caps the billing CV of an LDZ at 1MJ/m3 above the lowest CV gas in the zone, even a small volume of hydrogen (or other low CV gases such as non-propanated biomethane) can lower the billing CV and lead to under-recovery of energy, the cost of which is ultimately socialised.

The Future Billing Methodology (FBM) project has considered different options for addressing this challenge, and has now published its recommendations, including two main billing solutions:

1) No change to the current regime: FBM has found that blends of hydrogen and biomethane can be achieved under the existing billing framework with no change. Under this approach, local hydrogen blends would be controlled to maintain compliance with FWACV. FBM has recommended that gas transporters immediately proceed with developing this option. FBM has highlighted that this scenario would benefit from 'blending at high volume locations', i.e. hydrogen should be injected higher up the pressure tiers such that the blend can be distributed more evenly across a given LDZ. This scenario will also require careful flow management of low CV gases, again to distribute these gases more evenly across the LDZ.

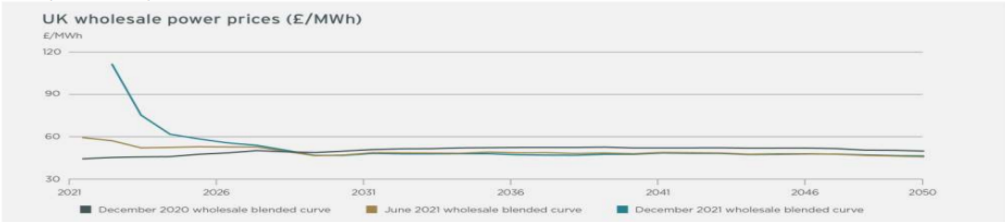
2) A modelled approach: FBM has also recommended exploring two options involving network modelling to create separate charging areas within LDZs. The first would create separate billing zones in the local vicinity of any lower CV injections, and the second would deliver a much more granular modelled CV value at system node level.

Either of these options would maintain accuracy of cost recovery in cases where low CV gases are unevenly distributed within an LDZ. A detailed feasibility study into a modelled approach will be undertaken by the gas networks, but is not a prerequisite to enable hydrogen blending. The main interaction between the settlement/billing approach and the rest of the commercial framework changes is that under a 'no change' approach, hydrogen blends will be constrained by FWACV rather than just the GSMR limit. There are also likely to be additional benefits from injections high up the pressure tiers (to avoid different gas blends entering different parts of an LDZ), and there may need to be more careful gas flow management, to ensure more homogenous blends across LDZs.

Hydrogen blending can commence while maintaining compliance with the Gas Calculation of Thermal Energy Regulations. Analysis has shown that significant blending capacity is available at higher flow locations such as the local and national transmission systems. In the short to medium term, billing reform will not be available or required to support building blending volumes at material levels. Blending can be managed within the existing Flow Weighted Average Calorific Value (FWACV) regime. Future reform should be weighed on its own merits in how it could support increasing hydrogen blending volumes, biomethane or build resilience for future changes of gas supply, including the potential for 100% hydrogen. Billing reform is not a pre-requisite for hydrogen blending.

Annex B – Curtailment Alleviation Analysis

Electricity Forecast Assumption

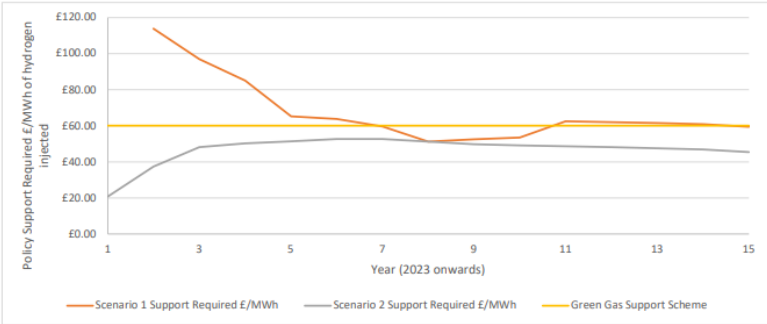


Electrolyser Capacity	10	MW_{H2}	
Electrolyser Spare Capacity	2.5	MW_{H2}	
Load Factor	25%		BEIS Hydrogen Production Costs 2021
Electrolyser efficiency	72.0%		BEIS Hydrogen Production Costs 2021
Hydrogen HHV	39.42	kWh/kg	
Average Hydrogen Production	15.85	kg/hr	
Hours Per Year	8760		
Days Per Year	365		
Electrolyser variable OPEX	3.8	£/MWh	
Transportation cost	5.0	£/MWh	
Blending CAPEX + OPEX (25% LF	1.1	£/MWh	

Year No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Wholesale £/MWh	£110	£100	£80	£70	£55	£53	£50	£45	£47	£48	£55	£55	£55	£55	£55
Gas Wholesale	£52	£35	£24	£22	£21	£20	£20	£21	£23	£23	£24	£24	£25	£25	£27
Solar/Wind CFD Price	£45	£45	£45	£45	£45	£45	£45	£45	£45	£45	£45	£45	£45	£45	£45
Hydrogen Production (tpa)	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Gas Injection Equivalence (MWh/annum)	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475
Electricity Con. MWh/annum	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604
Scenario 1 - Wholesale Electricity Cost (excluding non-commodity costs)															
Electricity Cost (£/annum)	-£836,458	-£760,417	-£608,333	-£532,292	-£418,229	-£403,021	-£380,208	-£342,188	-£357,396	-£365,000	-£418,229	-£418,229	-£418,229	-£418,229	-£418,229
Wholesale Gas Value (£/annum)	£282,535	£191,763	£132,377	£121,513	£115,251	£108,452	£108,284	£115,986	£123,939	£126,910	£129,951	£133,062	£136,246	£139,504	£147,177
Operating Loss Delta	-£553,923	-£568,654	-£475,957	-£410,779	-£302,978	-£294,569	-£271,925	-£226,202	-£233,457	-£238,090	-£288,278	-£285,167	-£281,983	-£278,725	-£271,052
Shortfall £/MWh	-£101.17	-£103.86	-£86.93	-£75.03	-£55.34	-£53.80	-£49.67	-£41.32	-£42.64	-£43.49	-£52.65	-£52.09	-£51.50	-£50.91	-£49.51
Electrolyser variable OPEX (£/MWh)	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80
Transport cost (£/MWh)	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00
Blending CAPEX + OPEX (25% LF) (£/MWh)	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11
Shortfall £/kg	-£2.57	-£2.63	-£2.21	-£1.90	-£1.40	-£1.36	-£1.26	-£1.05	-£1.08	-£1.10	-£1.34	-£1.32	-£1.31	-£1.29	-£1.26
Scenario 1 Support Required £/MWh		£113.77	£96.84	£84.94	£65.25	£63.71	£59.58	£51.23	£52.55	£53.40	£62.56	£62.00	£61.41	£60.82	£59.42

Scenarion 2 - Using Solar/Wind Marginal Cost of Production - £45/MWh - taken from latest CfD auction prices - https://www.carbonbrief.org/analysis-record-low-price-for-uk-offshore-wind-is-four-times-cheaper-than-gas/															
Electricity Cost (£/annum)	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188	-£342,188
Wholesale Gas Value (£/annum)	£282,535	£191,763	£132,377	£121,513	£115,251	£108,452	£108,284	£115,986	£123,939	£126,910	£129,951	£133,062	£136,246	£139,504	£147,177
Operating Loss Delta	-£59,653	-£150,425	-£209,811	-£220,674	-£226,936	-£233,735	-£233,904	-£226,202	-£218,249	-£215,277	-£212,237	-£209,125	-£205,941	-£202,683	-£195,010
Shortfall £/MWh	-£10.90	-£27.47	-£38.32	-£40.31	-£41.45	-£42.69	-£42.72	-£41.32	-£39.86	-£39.32	-£38.76	-£38.20	-£37.61	-£37.02	-£35.62
Electrolyser variable OPEX (£/MWh)	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80	£3.80
Transport cost (£/MWh)	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00	£5.00
Blending CAPEX + OPEX (25% LF) (£/MWh)	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11	£1.11
Scenario 2 Support Required £/MWh	£20.81	£37.38	£48.23	£50.22	£51.36	£52.60	£52.63	£51.23	£49.77	£49.23	£48.67	£48.11	£47.52	£46.93	£45.53
Green Gas Support Scheme	£60	£60	£60	£60	£60	£60	£60	£60	£60	£60	£60	£60	£60	£60	£60

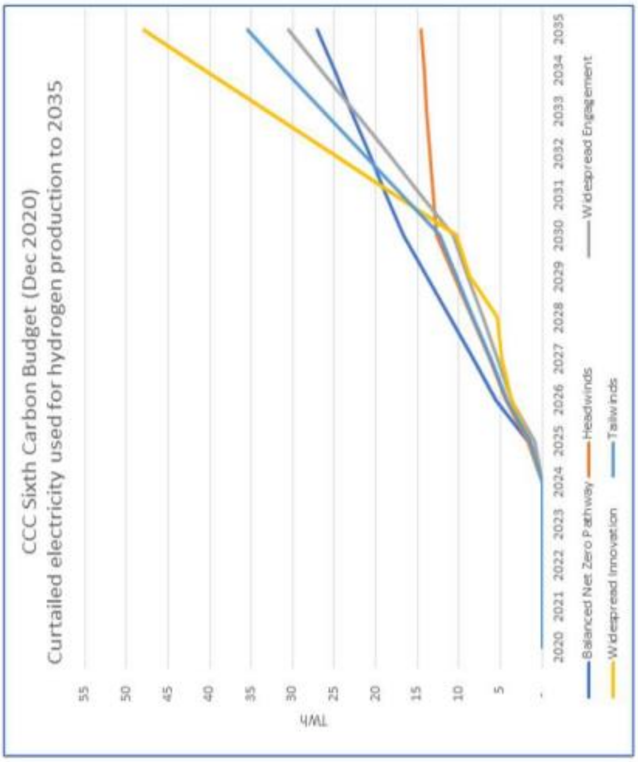
	Subsidy	CCE	
Scenario 1	60	-	234
Scenario 2	49	-	295
Green Gas Support Scheme (£60/MWh)	60		183

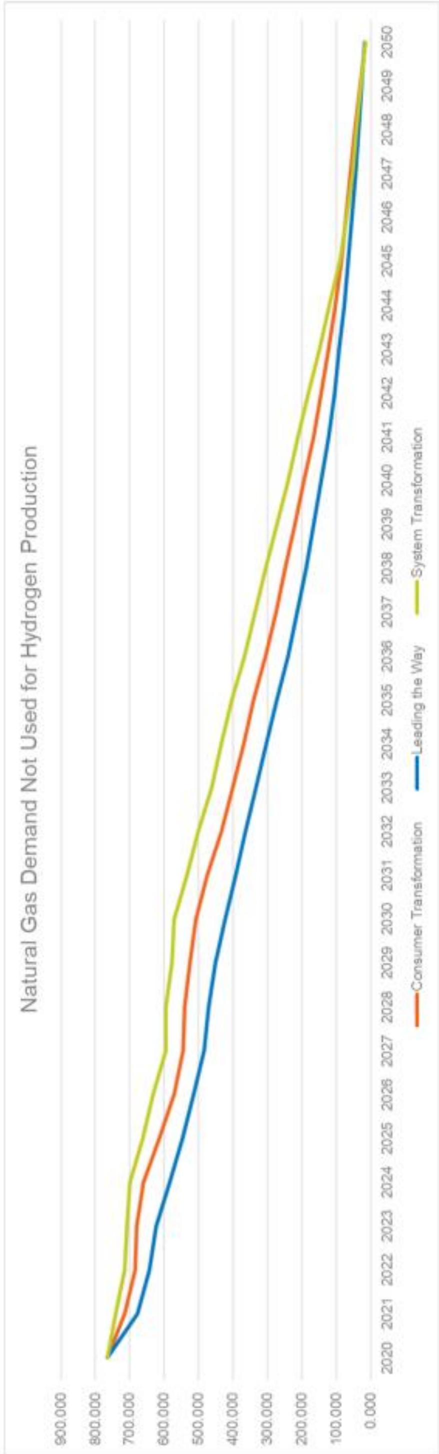


H2 by Volume (20% Cap)*

Year	FES Gas Demand Consumer Transformation	% of actual	% of 2021 volume	H2 that could be injected into Grid (TWh/annum)	Expected UK Curtailed Electricity (TWh/annum)	Natural Gas avoided (TWh)
2023	679.6	1.6%	1%	3.6	5	4
2024	660.8	2.6%	2%	5.8	8	6
2025	613.7	3.5%	2%	7.2	10	7
2026	572.1	5.3%	3%	10.1	14	10
2027	544.4	6.3%	4%	11.5	16	12
2028	539.9	7.6%	4%	13.7	19	14
2029	526.4	8.6%	5%	15.1	21	15
2030	508.5	9.3%	5%	15.8	22	16
2031	475.7	10.4%	5%	16.6	23	17
2032	434.4	12.4%	6%	18.0	25	18
2033	400.5	14.0%	6%	18.7	26	19
2034	369.3	15.2%	6%	18.7	26	19
2035	339.7	17.2%	6%	19.4	27	19
2036	306.0	19.8%	6%	20.2	28	20

20%* level discussed in policy is volume-based; therefore energy equivalent is c.3 x lower


CCC Sixth Carbon Budget (Dec 2020)
Curtailed electricity used for hydrogen production to 2035
TWh
Balanced Net Zero Pathway
Headwinds
Widespread Engagement
Widespread Innovation
Tailwinds


Natural Gas Demand Not Used for Hydrogen Production
Consumer Transformation
Leading the Way
System Transformation

From: https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2021

Fuel	Unit	kg CO_2e	kg CO_2	kg CH_4	kg N_2O
Natural gas	tonnes	2538.48	2533.69	3.44	1.34
	cubic metres	2.02135	2.01754	0.00274	0.00107
	kWh (Net CV)	0.20297	0.20258	0.00028	0.00011
	kWh (Gross CV)	0.18316	0.18282	0.00025	0.00010

	kgCO2e			
1kWh Natural Gas	0.18316			
1MWh	183.16	kgCO2e	0.18316	tonnes CO2e
1GWh	183,160	kgCO2e	183.16	tonnes CO2e
1TWh	183,160,000	kgCO2e	183160	tonnes CO2e

Curtailment Cost - https://reports.electricinsights.co.uk/q4-2020/record-wind-output-and-curtailment/
£74 per MWh

Year		H2 Exemption	H2 that could be injected into Grid (TWh/annum)	Electricity Required (TWh/annum)	Expected UK Curtailed Electricity (TWh/annum)	Potentially avoided Curtailment (TWh)	Avoided Gov Curtailment Spend (£)	Natural Gas avoided (TWh)	CO2 savings from natural gas avoidance (tpa)	Scenario 1 Support £/MWh	Scenario 1 Support £m	Scenario 2 Support £/MWh	Scenario 2 Support £m
	~~2023~~	~~2%~~	~~4~~	~~5~~	~~5~~	~~5~~	~~£371,052,632~~	~~4~~	~~659,376~~	~~£113.77~~	~~410~~	~~£37.38~~	~~135~~
	~~2024~~	~~3%~~	~~6~~	~~8~~	~~8~~	~~8~~	~~£593,684,211~~	~~6~~	~~1,055,002~~	~~£96.84~~	~~558~~	~~£48.23~~	~~278~~
	2025	4%	7	10	10	10	£742,105,263	7	1,318,752	£84.94	612	£50.22	362
	2026	5%	10	14	14	14	£1,038,947,368	10	1,846,253	£65.25	658	£51.36	518
	2027	6%	12	16	16	16	£1,187,368,421	12	2,110,003	£63.71	734	£52.60	606
	2028	8%	14	19	19	19	£1,410,000,000	14	2,505,629	£59.58	815	£52.63	720
	2029	9%	15	21	21	21	£1,558,421,053	15	2,769,379	£51.23	775	£51.23	775
	2030	9%	16	22	22	22	£1,632,631,579	16	2,901,254	£52.55	832	£49.77	788
	2031	10%	17	23	23	23	£1,706,842,105	17	3,033,130	£53.40	884	£49.23	815
	2032	12%	18	25	25	25	£1,855,263,158	18	3,296,880	£62.56	1,126	£48.67	876
	2033	14%	19	26	26	26	£1,929,473,684	19	3,428,755	£62.00	1,161	£48.11	901
	2034	15%	19	26	26	26	£1,929,473,684	19	3,428,755	£61.41	1,150	£47.52	890
	2035	17%	19	27	27	27	£2,003,684,211	19	3,560,630	£60.82	1,182	£46.93	912
	2036	20%	20	28	28	28	£2,077,894,737	20	3,692,506	£59.42	1,198	£45.53	918
Total			**185**	**257**	**257**	**257**	**£19,072,105,263**	**185**	**33,891,926**	**60.13**	**11,126**	**49.07**	**9,080**
			15.4										

Carbon Cost Effectiveness
From GGS Impact Assessment:

4.4 Carbon Cost Effectiveness

70. Under central modelling assumptions the Carbon Cost Effectiveness (CCE) for Option 1 (preferred option) is £173/tCO2e, while the CCE for Option 2 (alternative option) is £188/tCO2e [31]. These results show that the social cost per tonne of carbon abated for Option 1 is lower than Option 2.
71. Policies with a lower or negative number are generally thought to be better value for money. Where the cost effectiveness number is negative it implies there is net benefit to the economy per tonne of CO2 equivalent abated.

So Target for decarbonising the gas grid is £173/tonne

Using different Scenarios

		Total TWh of renewable gas in grid	Total Carbon Saved (tonnes)	Total curtailed electricity saved (TWh)	Total Support Cost	Curtailment Saving	Net Cost Total	CCE (£/tCO2e)
Assuming a policy support from 2023 to 2036	Support Rate (£/MWh)	185	33,891,926	257				
Scenario 1	60.13				£11,125,940,356	£19,072,105,263	-£7,946,164,907	-£234.46
Scenario 2	49.07				£9,079,940,356	£19,072,105,263	-£9,992,164,907	-£294.82