Department for
Energy Security
& Net Zero

Hydrogen Blending into GB Gas Distribution Networks

A consultation to further assess the case for hydrogen blending and lead options for its implementation, if enabled.

Closing date: 27 October 2023

September 2023

Any enquiries regarding this publication should be sent to us at: hydrogentransportandstorage@energysecurity.gov.uk.

Contents

General information

Why we are consulting

Hydrogen is one of a handful of low carbon solutions which can help the UK achieve its emissions reductions targets for Carbon Budget Six and net zero by 2050 as well as provide greater domestic energy security. In the UK's Hydrogen Strategy, government aimed for 5GW of low carbon hydrogen production capacity by 2030 for use across the economy.[1] The British Energy Security Strategy, building on these proposals, committed to doubling this 2030 hydrogen production capacity ambition to up to 10GW, with at least half coming from electrolytic production.[2]

Hydrogen blending refers to the blending of low carbon hydrogen with other gases (primarily natural gas) in pre-existing gas network infrastructure and appliances. We are assessing whether there may be value in having hydrogen blending available to support the early development of the hydrogen economy.

In the previous consultation on Hydrogen Transport and Storage Infrastructure, we explored the potential strategic role of hydrogen blending. In the response to that consultation, we set out our intention to further consult on hydrogen blending ahead of an intended policy decision on hydrogen blending into GB gas distribution networks.[3] We are now seeking stakeholder views to help inform our assessment of hydrogen blending's potential strategic and economic value and lead options for its implementation, if enabled.

[1] https://www.gov.uk/government/publications/uk-hydrogen-strategy
[2] https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[3] https://www.gov.uk/government/consultations/proposals-for-hydrogen-transport-and-storage-business-models

Consultation details

Issued: 15 September 2023

Respond by: 27 October 2023

Enquiries to: hydrogentransportandstorage@energysecurity.gov.uk

Or

Hydrogen Economy Team
Department for Energy Security and Net Zero
3-8 Whitehall Place
London
SW1A 2EG

Consultation reference: Consultation on Hydrogen Blending into GB Gas Distribution Networks

Audiences: This consultation will be of interest to stakeholders involved in the hydrogen economy and natural gas networks, including:

- Hydrogen producers
- Hydrogen consumers
- Gas transporters
- Gas shippers
- Gas consumers
- Storage operators
- Investors
- Consumer champions
- Trade associations
- Academics

Territorial extent:

The focus of this consultation is on hydrogen blending into GB gas distribution networks, however responses are invited from all parts of the UK. The Department for Energy Security and Net Zero will work with the Devolved Administrations as we assess the case for hydrogen blending to ensure that any recommended policies take account of devolved responsibilities. Where any proposals are suited to implementation on a UK or GB-wide basis, working with the devolved administrations will help to facilitate the successful deployment of these proposals and consistency with devolved policy.

How to respond

Your response will be most useful if it is framed in direct response to the questions posed, and with evidence in support wherever possible. Further comments and wider evidence are also welcome. When responding, please state whether you are responding as an individual or representing the views of an organisation.

We encourage respondents to make use of the online e-consultation wherever possible when submitting responses as this is the government's preferred method of receiving responses. However, responses in writing or via email will also be accepted. Should you wish to submit your main response via the e-consultation platform and provide supporting information via hard copy or email, please be clear that this is part of the same consultation response.

Respond online at: beisgovuk.citizenspace.com/industrial-energy/hydrogen-blending-gb-gas-distribution-networks

or

Email to: hydrogentransportandstorage@energysecurity.gov.uk

Write to:

Hydrogen Economy Team
Department for Energy Security and Net Zero
3-8 Whitehall Place
London
SW1A 2EG

Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential please tell us, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's [consultation principles].

If you have any complaints about the way this consultation has been conducted, please email: bru@energysecurity.gov.uk.

Chapter 1: Introduction

The hydrogen economy and hydrogen blending

Hydrogen can support decarbonisation of the UK economy, particularly in 'hard to electrify' UK industrial sectors, and can provide greener, flexible energy across power, transport and potentially heat. Hydrogen produced in the UK will create new jobs across the country, and secure greater domestic energy security, lowering our reliance on energy imports.

In 2021, the UK Government published the Net Zero Strategy, which sets out policies and proposals for decarbonising all sectors of the UK economy to meet our net zero target by 2050.[4] This supports the preceding publications of the Hydrogen Strategy and the Prime Minister's Ten Point Plan, along with other notable publications that set out the development of the hydrogen economy as a UK government priority. Building on the Ten Point Plan and Hydrogen Strategy, the British Energy Security Strategy doubled our 5GW low carbon hydrogen production capacity ambition to deliver up to 10GW by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen.[5] These strategies combine near term pace and action with clear, long-term direction to unlock the innovation and investment critical to meeting our energy security and net zero ambitions.

Hydrogen blending refers to the blending of low carbon hydrogen with other gases (primarily natural gas) in pre-existing gas network infrastructure and appliances. Government is aiming to reach a strategic policy decision in 2023 on whether the government should support blending of up to 20% hydrogen by volume into the GB gas distribution networks. We are assessing whether there may be value in having hydrogen blending available to support the early phases of the hydrogen economy. We are building the evidence to determine if blending meets the required safety standards, is technically feasible, economic, and supports government's broader strategic and net zero ambitions.

This consultation

We previously consulted on a potential strategic role for hydrogen blending to act as a reserve offtaker as part of the 2022 Hydrogen Transport and Storage Infrastructure Consultation,[6] to better understand the market-building benefits blending may be able to provide. This consultation seeks to further understand the potential strategic and economic value of blending. It also sets out our assessment of aspects of the commercial, market, technical and billing arrangements that could accommodate

[4] https://www.gov.uk/government/publications/net-zero-strategy
[5] https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[6] https://www.gov.uk/government/consultations/proposals-for-hydrogen-transport-and-storage-business-models

blending, should blending be supported and enabled by government. We are seeking stakeholder views on this current assessment of blending, including the economic analysis and whether any complexities and challenges identified in this consultation could be mitigated through careful policy planning and design. We have set out the lead options to address these, if blending were to be supported and enabled, and are seeking views on whether the potential implementation options we have identified are appropriate for stakeholders. The assessment in this consultation has been informed using the evidence that has been gathered to date. Further evidence on blending is being gathered and reviewed (as referenced in Chapter 2) which may affect the analysis and lead options for implementation that are presented in this consultation and help to inform the strategic policy decision intended in 2023.

Your feedback will enable us to develop informed policy.

Chapter 2 Nature of blending policy decision: Sets out the nature and scope of the intended blending strategic policy decision on blending into GB gas distribution networks, which we are aiming to reach in 2023. This chapter provides an update on the blending safety assessment and sets out considerations for potential regulatory changes. It invites feedback on the safety and usability of hydrogen blended gas and on considerations for transmission-level blending.

Chapter 3 Strategic role of blending: Sets out the proposed strategic role of blending as a reserve offtaker and a potential strategic enabler for certain electrolytic hydrogen producers to support the wider energy system, which has previously been consulted on as part of the 2022 Hydrogen Transport and Storage Infrastructure Consultation.

Chapter 4 Commercial support models: Considers options for whether, and if so how, blending may be commercially supported by government. This chapter invites feedback on a lead option that hydrogen blending, if enabled and supported by government, should be supported by the Hydrogen Production Business Model (HPBM). It sets out further considerations required for commercial support design which are outside the scope of this consultation.

Chapter 5 Market and trading arrangements: Sets out options for gas market and trading arrangements to accommodate blending. This chapter invites feedback on a lead option that hydrogen injected for blending, if enabled by government, could be purchased by both gas shippers and gas distribution network operators. It also considers how blending interacts with the Low Carbon Hydrogen Certification scheme and invites feedback on our lead option to preclude the onward trading of certificates for hydrogen injected into the existing GB gas distribution networks. It also considers how blending may interact with the UK Emissions Trading Scheme (ETS).

Chapter 6 Technical delivery models: Considers how hydrogen may interact with current gas delivery models. It invites feedback on a lead option that hydrogen blending, if enabled by government, should operate using the free-market technical delivery model, as described by the Gas Goes Green programme.

Chapter 7 Gas billing arrangements: Sets out options for gas billing arrangements for blending. This chapter considers how hydrogen may interact with current gas billing arrangements and potential options to amend these arrangements. It invites feedback on a lead option that hydrogen blending, if enabled by government, should operate within current gas billing arrangements. It also provides an update on blending interactions with gas meters.

Economic analysis: Presents the economic analysis, based on evidence to date, to help inform the strategic policy decision. This section includes a cost assessment of blending, and an accompanying annex explores case studies that consider the potential of different blending scenarios and describes the non-monetised costs and benefits of blending. This section invites feedback on the economic analysis presented.

Chapter 2: Nature and scope of blending policy decision

The consultation will help to inform an intended strategic policy decision in 2023 on whether, and if so how, government should support hydrogen blending into the GB gas distribution networks. This decision would confirm whether government, based on evidence to date, sees potential strategic and economic value for blending and whether government intends to provide any commercial support for hydrogen that is sold to be blended, if blending is enabled. If the strategic policy decision is positive, we would also look to provide further details on our intentions for the implementation of blending (such as gas billing arrangements), should blending be enabled.

A decision on whether to enable blending into the GB gas distribution networks may then be taken by government. This decision would be informed by the strategic decision and would also be subject to the gathering, submission and review of blending safety evidence. It would help determine whether any amendments to the Gas Safety (Management) Regulations 1996 (GS(M)R) and any other regulations are made, which we view as a requirement to enable blending at scale. The Department for Energy Security and Net Zero will work closely with industry and the Health and Safety Executive (HSE) to ensure that safety evidence is gathered and then independently and robustly assessed.

Outcomes from the broader safety review may have implications for the economic assessment and realisation of strategic benefits which we have set out as part of this consultation, especially if certain restrictions or conditions are required to ensure that blending is safe. Following completion of the safety review, government will also review the strategic policy decision on whether to support blending into the GB gas distribution networks to ensure that any implications on blending's feasibility and economic assessment are accounted for. For example, should there be significant additional costs (e.g. due to a requirement for network investment or deblending infrastructure) and/or significant time required to ensure that blending can be implemented safely, blending could be limited to certain regions or parts of the distribution network that do not require significant additional investment, impacting the benefits case.

If the outcomes from the strategic policy decision, the blending safety review and any subsequent review of the economic assessment support a decision to enable blending in the GB gas distribution networks, we would then look to start the legislative and regulatory process to implement this, as well as the process to make any physical changes to GB distribution networks that may be required. Given the timelines for this work, we do not anticipate blending at a commercial scale to commence in GB before 2025-26, at the earliest.

Chapter 4 of this consultation sets out our lead option for how government may provide commercial support for blending, if blending is supported by government. Further work would be needed on the detailed commercial design and allocation of any support mechanism which would be done following the intended strategic decision in 2023. We will continue to engage with stakeholders on the design of any commercial support for blending, if blending is supported, as we develop further thinking and policy positions in these areas (such as via working groups and bilateral engagement).

Safety case

We view that enabling blending at scale requires amendments to the GS(M)R, which currently limit the amount of hydrogen in the existing gas networks to 0.1% by volume.

Hydeploy, an industry consortium, is undertaking blending trials and demonstrations to gather evidence to demonstrate whether and/or how blending can be used safely in the GB gas distribution networks. The first trial took place at Keele University on a private gas network,[7] and the second trial took place in the village of Winlaton near Gateshead, in North East England.[8] The evidence gathering process is currently expected to complete in 2023.

As mentioned in the previous section of this chapter, this gathered safety evidence needs to be reviewed by government before any amendments to the GS(M)R are made. The Department will work closely with the HSE to ensure that safety evidence is assessed independently and robustly. Given the expected timelines for the evidence submission and subsequent review we anticipate this assessment will not be completed in 2023. We therefore anticipate that there will be a need to separate the safety case from the strategic and economic case. Any initial policy decision on blending will likely be a strategic decision, based on strategic and economic considerations and subject to the outcome of the wider safety review. It will be a decision on whether, and if so, how government should support blending, should it be safe to do so.

Future Grid, a project led by National Gas, is undertaking trials for blending in the National Transmission System (NTS) and testing blend rates of up to 20% hydrogen by volume. These tests may help to inform a separate decision on transmission-level blending (as explored later in this chapter).

Note that any amendments to the GS(M)R cover GB only and it would be for the Health and Safety Executive Northern Ireland (HSENI) to decide whether to adopt any similar arrangements to the Gas Safety (Management) Regulations (Northern Ireland) 1997 (GS(M)R(NI)).

GS(M)R exemptions

If the blending strategic policy decision is positive, hydrogen production projects wishing to blend could apply to the HSE for project specific exemptions to GS(M)R to allow blending ahead of competition of a full safety review and any future GS(M)R amendments. This exemption process has enabled biomethane injections into the grid but would be more challenging for hydrogen blending, as the different physical properties of hydrogen and natural gas (which primarily consists of methane) would

[7] https://hydeploy.co.uk/project-phases/#phase-1-keele (Accessed in September 2023)
[8] https://hydeploy.co.uk/project-phases/#phase-2-winlaton (Accessed in September 2023)

likely mean the level of safety evidence required and time taken to consider such an exemption would be greater. Hydrogen producers seeking to blend hydrogen under a GS(M)R exemption would likely need to gather site-specific safety evidence. Any exemption granted may be time-limited, with associated investment risk, and the length of exemptions may vary from project to project as determined by HSE’s assessment of the safety evidence reviewed for a particular project.

If the blending strategic policy decision is positive, but the outcome from the safety review does not support implementing amendments to GS(M)R, or blending is allowed in limited circumstances only, then there may still be potential for projects to apply for regulatory exemptions on a case-by-case basis.

Impact of blending on industrial users connected to GB gas distribution networks

In addition to the trials and testing on the safety of blends for industrial users, for instance power generators, this consultation is looking to gather evidence to further understand the potential impact of receiving fixed or variable hydrogen blends of up to 20% hydrogen by volume on industrial users connected to the existing GB gas distribution networks. We would like to understand if any mitigations may be required, such as deblending.

Question 1.

a) Do you have any concerns around the safety or usability of hydrogen blends of up to 20% by volume in the GB gas distribution networks?

b) If so, is this dependent on whether the blend is a fixed or variable percentage (up to 20% by volume)?

c) If applicable for your project, do you anticipate any cost impact to your business (e.g. from replacing equipment, adjusting production levels or requiring deblending equipment and processes)?

d) If applicable, how long would you require to prepare your facilities to accept fixed or variable hydrogen blends? Would there be a substantive difference depending on whether the blend is a fixed or variable percentage?

e) Please provide supporting evidence about any impacts you may expect and estimates for the costs of mitigation, if applicable.

Blending into GB gas transmission networks

There are further considerations associated with transmission-level blending that will need to be evaluated as part of the economic and safety assessments for transmission-level blending. These include the impact of blends and/or varying blend rates on industrial end users connected at transmission-level and the possible need for mitigations such as deblending, with associated costs. We anticipate that this may be more significant for larger-scale transmission connected industrial users, compared to users connected at distribution-level.

Government will also consider developments across Europe, such as in relation to the EU Hydrogen and Gas Market Decarbonisation package, which initially proposed a regulatory obligation on transmission system operators throughout the EU to accept blends of up to 5% by volume at interconnection points. Since then, the EU Parliament and EU Council have separately proposed lower blend percentages. The EU is yet to agree its final decision on blending at internal interconnection points between Member States and is also yet to agree a position for regulating interconnection with Third Countries. Further consideration will be given to EU Gas Package timings, the blending plans of countries that we share interconnectors with and implications for trade agreements as we assess the case for blending into GB gas transmission networks.

As mentioned above, evidence being gathered from the Future Grid project trials which are testing blending at transmission-level is expected to be available for review in late 2023 with a further trial planned in 2024.

Any strategic policy decision on blending taken in 2023 will be based on blending into the existing GB gas distribution networks only. Government will separately assess the case for supporting blending into GB gas transmission networks, which may be subject to a separate policy decision at a later date. We may provide further details on the expected timelines for this assessment and decision alongside the planned strategic policy decision on blending into GB gas distribution networks.

Question 2. Do you have any additional views or concerns associated with blending hydrogen into GB gas transmission networks that have not been identified within this chapter? Please provide evidence to support your response.

Chapter 3: Strategic role of hydrogen blending

There may be value in having blending available to support the early development of the hydrogen economy. Blending may be able to play a role in managing the risk of hydrogen producers being unable to sell sufficient volumes of hydrogen, for example, if an offtaker (e.g. an industrial facility) is no longer able to buy hydrogen from the producer (known as “volume risk”) impacting the production project’s revenue. Blending may also help to mitigate volume risks relating to development of hydrogen transport and storage infrastructure, for example if an infrastructure project is delayed. Blending may help mitigate volume risk for hydrogen producers suitably located to blend and/or with any required transport infrastructure, under scenarios where a local blending limit (e.g. 20% by volume) has not already been reached. This could help to reduce investment risk into hydrogen production and in certain circumstances may have the potential to lower production costs, as explored in the Economic Analysis section of this consultation.

In addition to this and in the initial absence of larger-scale hydrogen transport and storage infrastructure, blending may also have value in strategically enabling electrolytic hydrogen producers to support the wider energy system. This could be beneficial for electrolytic hydrogen producers located behind electricity network constraints using excess renewable electricity that would otherwise have been curtailed. We do not envisage Carbon Capture Usage and Storage (CCUS)-enabled hydrogen projects playing this role and would be unlikely to support those where blending is a majority offtaker.

However, we believe that blending should only be a transitional option. It relies on an extensive natural gas network being available to blend into, which will reduce as we progress to net zero. For this reason, it may only have a limited and temporary role in gas decarbonisation as we move away from the use of natural gas. As set out in the UK Hydrogen Strategy, the use of hydrogen is expected to be most valuable where there are limited alternative routes to decarbonisation, such as for industries for which direct electrification is not an option.[9]

As such, we believe an appropriate strategic role for blending, if blending is supported and enabled by government, is to act as a reserve offtaker, to support the growth of the hydrogen economy whilst ensuring it does not ‘crowd out’ the supply of hydrogen to alternative end users who require it to decarbonise. Additionally, it may have value as a potential strategic enabler for certain electrolytic hydrogen projects to support the wider energy system. This strategic role is likely to be reflected in the design and allocation of any government commercial support made available for volumes of hydrogen that are sold to be blended into gas networks (see Chapter 4 for further details).

Blending 20% hydrogen by volume into the GB gas distribution networks could generate carbon-savings of up to 6-7% on consumption of that gas. However, the

[9] https://www.gov.uk/government/publications/uk-hydrogen-strategy

primary strategic role of blending is not to decarbonise the existing gas network and facilitate a transition to heat decarbonisation. Similarly, a decision on 100% hydrogen for heat is not contingent on a decision on blending. Alongside our work on blending, the government is working with industry and regulators on a range of research, development and testing projects, including community trials, to enable strategic decisions in 2026 on the role of 100% hydrogen for heat. In light of these decisions, and as the hydrogen economy develops beyond our initial blending policy decision, we will continue to assess the strategic role and value of blending.

Previous consultation on the strategic role of blending

In August 2022, government published a consultation on proposals for hydrogen transport and storage infrastructure.[10] This consultation included a chapter on hydrogen blending which sought to better understand the hydrogen market-building potential of allowing hydrogen blending into the existing gas grid. The chapter provided the rationale for a strategic role for blending to act as a reserve offtaker, to support hydrogen economy growth whilst ensuring that blending does not impact the availability of hydrogen to other end use sectors who require it to decarbonise. It also considered blending's potential value in strategically enabling certain electrolytic hydrogen producers to help support the broader energy system ahead of hydrogen transport and storage infrastructure.

The consultation responses received indicated that there is stakeholder support for this strategic role of blending and its potential to help manage volume risk. A summary of the consultation responses received can be found in the response to that consultation.

Question 3. Do you have any comments on our views of the strategic role of blending, as described in this chapter? Please provide evidence to support your response.

[10] https://www.gov.uk/government/consultations/proposals-for-hydrogen-transport-and-storage-business-models

Chapter 4: Commercial support models

As set out in Chapter 3, we consider an appropriate strategic role for blending, if supported and enabled, would be to act as a reserve offtaker, to support hydrogen economy growth whilst managing any impact of blending on the availability of hydrogen to other end users who require it to decarbonise. Blending could also play a role of strategic enabler for certain electrolytic projects in certain locations to help manage grid constraints ahead of regional or national hydrogen transport and storage infrastructure.

In developing the economic case for blending, government has been considering whether blending should be supported commercially by government if it is enabled, and if so, options for how commercial support could be provided, in line with the strategic role. The assessment in this chapter considers the extent to which each option is likely to be most effective in delivering the strategic objectives of blending whilst ensuring blending does not impact the availability of hydrogen to other end use sectors who require it to decarbonise. If hydrogen volumes produced for blending are overly incentivised by government, it may risk displacing the supply of hydrogen to other end use sectors. However, if blending is not sufficiently supported there is a risk that blending may not be viable for producers and potential benefits may not be fully realised. Consideration has been given to the achievability and deliverability of each option within the required timeframes to realise the strategic benefits.

Commercial support options

Four options are considered for the commercial support for blending which are set out below.

- **Option 1: No government commercial support provided.** Under this option, if blending is enabled from a technical and regulatory perspective, government would not provide any commercial support for hydrogen that is produced for blending. Despite recent increased gas prices, because the levelised cost of hydrogen production is currently high, the price of unsupported hydrogen is expected to remain above the natural gas price forecast during the early development of the hydrogen economy, when blending would potentially have the most benefit. Therefore, our assessment is that it is highly unlikely any blending would occur without commercial support as the price of hydrogen would not be competitive with natural gas, which is consistent with feedback we have received from stakeholders and is a challenge not limited to blending as an offtake. There is a further risk that enabling blending without providing any government commercial support could incur unnecessary costs and time implementing any required network and regulatory changes as it would not likely be viable for hydrogen producers. This option would therefore likely fail to deliver the strategic benefits of blending.

- **Option 2: Provide government commercial support for blending through a new framework to succeed the current Green Gas Support Scheme (GGSS).** The existing Green Gas Support Scheme, which provides support for biomethane producers injecting into the gas grid, is open for applications until 2025 (government has recently consulted on a possible extension following difficulties in securing waste feedstocks to meet eligibility requirements and supply chains issues),[11] and we are currently working to develop a policy framework to follow the GGSS when it closes for applications. It may be possible to expand any new policy framework to incorporate low carbon hydrogen injection to the gas grid, though consideration would need to be given to the legal powers required for this. The primary strategic objective of hydrogen blending (supporting the growth of the hydrogen economy) would likely be distinct from objectives of biomethane policy. Any limited decarbonisation of the existing gas network from hydrogen blending would be a secondary benefit. It may therefore be challenging to design a policy framework that can successfully meet these potentially distinct policy objectives. Given decisions have yet to be made on the nature of a future policy framework for biomethane, which may require legislative and regulatory changes, and a strategic decision on whether to support hydrogen blending is planned for 2023, this option would likely not meet the deliverability criteria or achieve the strategic objectives of blending.

- **Option 3: Design a new business model to provide government commercial support for blending.** Developing a new business model tailored to support blending would require extensive time and resource to design and subsequently implement a new commercial support mechanism, which would likely require legislative changes and not meet the deliverability ambitions and therefore the strategic objectives of blending.

- **Option 4: Incorporate blending as an eligible offtaker into the Hydrogen Production Business Model (HPBM).** The HPBM has been designed to provide revenue support to new low carbon hydrogen production projects and is based on a Contracts for Difference-style framework. Whilst hydrogen produced for blending is currently defined as a non-qualifying offtaker under the HPBM and a producer is therefore not eligible to receive subsidy support, this restriction could be amended to enable a producer to receive subsidy support for the sale of hydrogen for the purposes of blending. In amending the HPBM, consideration would need to be given as to the level of subsidy support for volumes sold to blend, consistent with blending's strategic role. Supporting blending through the HPBM, rather than via a separate business model, would reduce administrative burdens for producers, the government and the government appointed counterparty to manage the HPBM contracts.

[11] https://www.gov.uk/government/consultations/green-gas-support-scheme-mid-scheme-review

Lead commercial support model for hydrogen blending

Based on the appraisal above, we consider that the most appropriate mechanism, if blending is enabled and commercially supported by government, would be the HPBM. This is subject to further analysis. We will also consider the timing for when the HPBM can be adapted and the impact on any existing HPBM contracts already awarded.

Question 4. Do you agree that, if blending is enabled and commercially supported by government, the most appropriate mechanism would be via the Hydrogen Production Business Model? Please provide evidence to support your response.

Further considerations for the Hydrogen Production Business Model

In designing any subsidy support for blending and integrating this within the HPBM, consideration will be given to blending's strategic role as set out in Chapter 3. In particular, we are keen to avoid distorting the offtaker market that could result in blending 'crowding out' other end users of hydrogen who require it to decarbonise by determining any conditions or criteria under which subsidy support may be provided. Any subsidy support provided for blending would need to be reflected in the Hydrogen Production Business Model contract and the Low Carbon Hydrogen Agreement (LCHA), where blending is currently a non-qualifying offtaker. This will include how the LCHA would accommodate blending, interaction with existing design measures within the HPBM (e.g. sliding scale and Risk Taking Intermediaries), technical requirements (e.g. metering and billing) and the level of subsidy support for blending volumes. The work will also consider the potential role blending could play for certain electrolytic hydrogen production projects (as outlined in Chapter 3).

We will continue to engage with stakeholders on the design of any subsidy support for blending as we develop further thinking and policy positions in these areas (via working groups and bilateral engagement), including blending's potential eligibility as a qualifying offtaker for future contract allocation rounds via the Hydrogen Allocation Rounds and the CCUS Cluster Sequencing Process. We currently envisage a Carbon Capture, Usage and Storage (CCUS)-enabled hydrogen project only including blending as a reserve offtaker, but for electrolytic projects there may be a case for supporting blending as a strategic enabler to manage grid constraints as a precursor to regional or national hydrogen transport and storage infrastructure in certain locations. If blending is supported and the HPBM considered the most appropriate mechanism, we would aim to reflect any amendments within a future iteration of the LCHA and consider whether/how these can be reflected in LCHAs previously entered into.

Chapter 5: Market and trading arrangements

This chapter considers the market and trading arrangements for hydrogen blending, if enabled, in the context of the current gas market and trading arrangements, including the question of which market participants could purchase hydrogen produced for blending. In addition, this chapter sets out blending interactions with any low-carbon hydrogen certification schemes and the UK Emissions Trading Scheme (UK ETS).

Which market participants could purchase hydrogen produced for blending?

Under existing gas market arrangements, gas shippers are responsible for bringing gas onto the network, trading it with suppliers to deliver to end consumers and balancing supply and demand across the network. Gas Distribution Network (GDN) operators also have an obligation under the Uniform Network Code (UNC) to procure shrinkage gas to replace gas lost from the network through own use, leakages, theft, or otherwise unaccounted for.

The nature of blending (injecting low carbon hydrogen into the existing gas network to be mixed with other gases) means that once hydrogen is injected it is unlikely to be feasible to determine exactly where on the network the physical hydrogen molecules disperse to and which consumers will receive a blend.

We considered two primary options for blending market and trading arrangements, which are not mutually exclusive, and a third 'hybrid' approach.

- **Network-led approach:** For this option, the GDN operators would act as the buyers for volumes of low-carbon hydrogen that are sold by hydrogen producers for the purposes of blending. Any volumes of hydrogen purchased for blending could be used as part of the GDN operators' existing 'shrinkage gas' obligations. Shrinkage gas accounts for roughly 0.5% of gas transported on the networks (by volume), so could be a smaller scale means of enabling blending.

- **Shipper-led approach:** For this option, gas shippers would act as the buyers for volumes of low-carbon hydrogen that are sold by hydrogen producers for the purposes of blending. Gas shippers could trade hydrogen through existing gas market arrangements.

- **Hybrid approach:** Under this approach, both GDN operators and gas shippers would be permitted to act as the buyers for volumes of low-carbon hydrogen produced for blending, much like how the current gas system operates with natural gas.

Each of these options could theoretically facilitate the implementation of blending and support its strategic objective to accelerate the early growth of the hydrogen economy. Both the network and shipper-led approaches could also achieve the strategic role set out in Chapter 3 of this consultation. As set out in Chapters 4 and 8 of this consultation, the future design of any commercial arrangements for blending, if supported and enabled by government, will consider blending's strategic role.

Both the network and shipper-led approaches could be accommodated with minimal regulatory change. Under the shipper-led approach, gas shippers could buy and sell hydrogen on the basis of energy content as they currently do today with natural gas. This would require minimal change to the current trading arrangements.

The network-led approach alone could potentially limit blending as current 'shrinkage' obligations constitute approximately 0.5% of total gas transported by volume, potentially limiting blending to approximately 0.5% hydrogen by volume. Hydrogen production may not be geographically evenly spread across all GDNs, which may further limit the potential for hydrogen blending in geographic areas with more significant hydrogen production capacity.

We note that sales of hydrogen to Risk Taking Intermediaries (RTIs, which would include gas shippers) are not currently an eligible offtaker under the Hydrogen Production Business Model (HPBM). As set out in Chapter 4 of this consultation, further consideration will be given to the commercial design and integration of blending, if blending is supported by government, within the HPBM.

Lead option for purchase of hydrogen produced for blending

Given the above considerations and based on the evidence gathered and assessed to date, our lead option would be to allow a hybrid approach for blending market and trading arrangements where both GDN operators and gas shippers are able to purchase hydrogen produced for blending, and shippers are able to sell hydrogen produced for blending, if blending is enabled by government.

Question 5. Do you agree with the proposed lead option to allow both gas distribution network operators and gas shippers to purchase hydrogen produced for blending? Please provide evidence to support your response.

Low Carbon Hydrogen Certification Schemes

The government has committed to setting up a certification scheme for low carbon hydrogen by 2025 and consulted in Spring 2023 on proposals for the scheme's design.[12] The scheme aims to provide a way for producers to prove the emissions credentials of their hydrogen and will be initially based on the Low Carbon Hydrogen

[12] https://www.gov.uk/government/consultations/uk-low-carbon-hydrogen-certification-scheme

Standard (LCHS).[13] These certificates would also enable end users to demonstrate and have confidence that the hydrogen they purchased is low carbon. Producers may benefit financially as certificates could provide a 'low carbon premium' where end users see a value in buying certified hydrogen. Other certification schemes for low carbon hydrogen are in existence already (e.g. TÜV SÜD)[14] and further schemes led by industry may emerge. These schemes will likely vary in their design but will provide similar benefits, including if certificates were traded alongside blended volumes of low carbon hydrogen.

After hydrogen has been certified as low carbon hydrogen there may be some scenarios where that certified hydrogen will be blended. When considering how certificates for low carbon hydrogen should be treated in a blending scenario, consideration should be given to blending's strategic role as a reserve offtaker (as set out in Chapter 3) to ensure blending does not 'crowd out' the supply of hydrogen to other offtakers.

If certificates for blended volumes are tradable, this could create a commercial incentive for hydrogen producers to prioritise blending over other offtakers, as they could extract a price premium for certificates issued to gas shippers who could onward trade to suppliers/retail market and extract further value in the form of low carbon energy products and tariffs.

Government is therefore minded to disincentivise certificates (from both the government scheme and similar schemes) from being traded. We intend to preclude the onward sale of certificates after the point of injection when volumes of low carbon hydrogen are blended into gas networks.

We would develop the details of this position alongside the development of the certification scheme and any amendments to the choice of commercial support (see Chapter 4 above) that may occur to accommodate hydrogen blending.

Question 6. Given blending's proposed strategic role as a reserve offtaker, do you agree that certificates for low carbon hydrogen injected into the gas network should be precluded from onward sale after the point of injection? Please provide evidence to support your response.

Interaction with the UK Emissions Trading Scheme (UK ETS)

The UK Emissions Trading Scheme (ETS) aims to incentivise cost effective reductions in greenhouse gas emissions for eligible industry sectors. It is a cap-and-trade system which caps the total level of emissions, creating a market with a carbon price signal to incentivise decarbonisation. Participants in the scheme are required to

[13] https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria

[14] https://www.tuvsud.com/en-gb/themes/hydrogen/hydrogen-services-that-enable-safety-for-your-ideas/green-hydrogen-certification (Accessed in September 2023)

obtain and surrender allowances to cover their annual greenhouse gas emissions. Participants can purchase allowances at auction or trade them amongst themselves, which allows the market to find the most cost-effective way to reduce emissions and for those involved to benefit economically.

Allowing hydrogen to be injected into the existing GDNs will impact ETS participants that receive a blend. Depending on how participants measure their greenhouse gas emissions, they may either be commercially disadvantaged or benefit.

There are two approaches for an ETS participant to monitor their greenhouse gas emissions.

- **Volume-based approach:** A participant monitors their emissions via a calculation-based approach, determined from the volume of gas burned. A participant served with a blend will require a greater proportion of gas (due to hydrogen's lower calorific value (CV)), meaning their calculated ETS emissions would increase, requiring additional ETS allowances to be purchased.
- **Measurement-based approach:** A participant physically monitors their emissions via a measurement-based approach, determined from the concentration of greenhouse gas in their flue-gas flow. This approach could benefit a participant receiving a blend as it reduces their need to purchase ETS allowances as hydrogen releases no carbon emissions when burned.

Further, the geographical location of an ETS participant is an arbitrary factor that could impact fairness under the UKETS. For example, an ETS participant located near a hydrogen injection point is likely to receive a higher concentration of blend than a participant located further away as the hydrogen molecules will have less space to disperse. Under a measurement-based approach, such a situation would result in the farther-away participant being disadvantaged in comparison, through no decision of their own.

Mitigations

The Monitoring and Reporting Regulations (MRR) 2018 govern how ETS participants are required to monitor/report their ETS emissions. These regulations provide ETS participants some flexibility in terms of which methodology they use. Whilst the regulator would need to approve a new methodology/emissions monitoring plan, it is not assessed that this would be challenging, or incur significant costs for participants, given a priority list of ETS participants can be identified based on injection locations.

Other options considered include:

- **Requiring that networks provide CV data of gas to ETS participants:** This option would enable ETS participants to measure their emissions from the CV of gas served.
- **Adjusting how ETS participants measure their emissions:** ETS participants would be required to measure both the volume of fuel burned and

flue-gas emissions. From this they can calculate the CV of the blend received and hence better measure their ETS emissions.

However, both of these options are likely to require a substantial number of changes to the regulations and take considerable time to implement and redesign new options for monitoring emissions. This could lead to significantly higher administrative costs on ETS participants. Further, the Environment Agency confirmed that currently the largest participants will determine their emissions from natural gas by measuring the calorific value using gas chromatography and multiplying by the volume of gas burned. In effect this means the second option listed above is already in operation for larger participants with gas chromatographers.

Proposed policy position

The existing regulations provide ETS participants some flexibility in terms of which methodology they use to monitor emissions and include provisions enabling operators to install measurement devices if they require more accurate values. This would allow participants who are adversely impacted by receiving a hydrogen blend to change their methodology and manage the risk of any competitive distortions.

The government therefore proposes to take no action to amend the UK ETS to accommodate hydrogen blending, if enabled.

Chapter 6: Technical delivery models

Current gas delivery models

When discussing technical delivery models for hydrogen blending, we are considering the question of where hydrogen would be injected into the GB gas networks and how this should be managed. As the purpose of this consultation is to better understand distribution-level blending (as explained in Chapter 2), we are focusing on technical delivery model options for inputting hydrogen into the gas distribution networks (GDNs) and not the national transmission system (NTS) in this chapter. Before considering the technical delivery models options for hydrogen blending into the GDNs, it is important to understand how the gas networks currently deliver gas to customers (also referred to as end users) in Great Britain.

The NTS is the high-pressure gas network. It transports gas at pressures of up to around 94 bar (approximately 94 times the normal atmospheric pressure) around Great Britain via thousands of kilometres of pipelines. Gas is input into the NTS from various sources, such as from liquified natural gas (LNG) terminals and gas fields in the UK Continental Shelf. The NTS connects to gas storage facilities and with other nations to trade gas via interconnectors and pipelines. It delivers gas directly to some large-scale end users, such as power stations and large industrial plants, but the NTS transports gas at too high a pressure to deliver gas directly to most end users, such as smaller-scale industries and domestic end users.

Gas is transferred from the NTS to lower pressure GDNs to deliver gas to most end users. The NTS supplies gas to eight GDNs, each covering a separate geographical region in Great Britain. These GDNs receive high pressure gas from the NTS and progressively reduce the pressure of the gas in stages. Each GDN is comprised of four tiers of pipeline pressure, as outlined below:[15]

- High Pressure (HP): Greater than 7 bar
- Intermediate Pressure (IP): 2-7 bar
- Medium Pressure (MP): 0.075-2 bar
- Low Pressure (LP): Less than 0.075 bar

Most end users are located at the lower end of these pressure tiers (such as domestic customers and small businesses), although end users can connect at any tier.

The NTS supplies most of the gas that is transported in the GDNs, although some smaller-scale gas producers also input gas directly into the GDNs. This currently includes producers of biomethane, a low carbon substitute for natural gas, and could

15 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566152/climate-adrep-national-grid-gas.pdf

also include producers of hydrogen in future. Currently, the Gas Safety (Management) Regulations 1996 (GS(M)R) limit the amount of hydrogen in the gas networks to 0.1% by volume, significantly limiting the potential to input hydrogen except where an exemption to the GS(M)R has been granted.

Considerations for delivering hydrogen via gas networks

The current gas delivery model, outlined above, predominantly transports natural gas to deliver to end users. A deviation from this is where biomethane is injected into the gas grid, mostly via the GDNs. However, the chemical and physical properties of natural gas and biomethane are very similar because natural gas consists primarily of methane (along with small amounts of other gases such as ethane, butane and pentane).[16] Some action may be taken to bring the properties of natural gas and biomethane into closer alignment (such as propane 'enrichment' of biomethane, further explored in Chapter 7) but the difference in properties between the two gases is so small that biomethane can be injected into gas networks safely without requiring significant changes to current gas delivery systems and/or current gas infrastructure and end user appliances.

The difference in physical properties between natural gas and hydrogen is much greater. Hydrogen is a small molecule compared to the gases that compose natural gas, for instance, which increases the potential for leakage when hydrogen is transported via gas networks and may increase the likelihood and potential severity of mechanical damage in some conventional gas pipelines. Hydrogen also has different flame properties, which can impact end user appliances designed for natural gas. Benefits of hydrogen use include that, unlike natural gas (primarily consisting of methane, CH_4), hydrogen has no carbon in its chemical formula. This means that when hydrogen (H_2) and oxygen (O_2) combine in combustion, the by-product is water vapour (H_2O) with no carbon emissions released. These different properties mean that some aspects of current gas delivery systems and/or current gas infrastructure and appliances may be unsuitable for use with hydrogen.

This is why the strategic policy decision we intend to reach relates to blending of up to 20% hydrogen by volume. Blending of 20% hydrogen by volume is regarded by industry as the limit by which if exceeded, domestic and non-domestic appliances could start to be negatively impacted, for instance relating to boiler ignition performance. Exceeding the 20% hydrogen blend level may require nationwide retrofitting of appliances and/or gas network infrastructure, which could require significant cost and time. Safety trials and demonstrations are currently being finalised by HyDeploy, an industry consortium, to gather evidence on the impacts of hydrogen blending of up to 20% by volume on GDN infrastructure and connected end users. This gathered safety evidence needs to be presented to and then reviewed by government before any amendments to the GS(M)R are made, which we view as a requirement to enable blending at scale. The Department for Energy Security and Net Zero will continue to work closely with industry and the Health and

[16] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/545567/Material_comparators_for_fuels_-_natural_gas.pdf

Safety Executive (HSE) to ensure that safety evidence is gathered and then independently and robustly assessed.

If hydrogen blending was to be enabled in GDNs and limited to 20% by volume, then there is a question of where blended hydrogen should be injected into the GDNs. This question helps determine how blended hydrogen would be delivered to end users that are connected to the GDN and is explored in the next sections of this chapter.

Technical delivery model options for hydrogen blending

The Gas Goes Green programme, delivered by the Energy Networks Association (an industry body representing the UK and Ireland's energy networks), identified two potential technical delivery models for inputting hydrogen blends into the GDNs and described them as the 'strategic approach' and 'free-market approach', as outlined below.[17]

- **Strategic approach:** This approach would designate locations where injecting hydrogen into the GDNs could occur, based on the most suitable parts of the network for blending (with various considerations for determining this). For example, injections of hydrogen could be designated to take place only at the NTS offtake site (as explored in the appraisal below).
- **Free-market approach:** This is the least-change option. This approach would mimic the existing arrangements for connections to the gas network and would let the market decide where to inject hydrogen into the GDNs.

For both options, it would be for the GDN operators to govern capacity allocation for volumes of hydrogen injected to ensure the maximum blend limit is not breached.

Appraisal of technical delivery model options for hydrogen blending

Consideration was given to the strategic approach, as described by the Gas Goes Green programme, as it theoretically has several potential benefits. If inputting hydrogen into the GDNs was designated to only occur at the NTS offtake site (the point of gas supply from the NTS into a GDN), for instance, then this may offer benefits such as those outlined below.

- **Reduced complexity to allocate gas network capacity:** Hydrogen producers that are connected 'upstream' on the network (i.e., at higher pressure tiers of the GDN, closer to an NTS offtake site) could potentially input enough hydrogen to reach the maximum blend level (e.g., 20% hydrogen by volume) in that region of the GDN. This blended gas would then flow 'downstream' including into lower-pressure tiers of the GDN. For any

[17] https://www-energynetworks-org.webpkgcache.com/doc/-/s/www.energynetworks.org/industry-hub/resource-library/britains-hydrogen-blending-delivery-plan.pdf (Accessed in September 2023)

hydrogen producers connected downstream, if the gas flowing into their region of the network already contains a maximum hydrogen blend level, then this could prevent them from injecting hydrogen (as to do so could breach the maximum blend level). Determining which hydrogen producer should be able to inject hydrogen at different locations across the GDN therefore requires careful management to ensure appropriate gas network capacity allocation (which determines where gases can be input into the network) without breaching the maximum blend level. A strategic approach designating that hydrogen could only be input at an NTS offtake site may help to avoid this complexity, as producers would not be able to connect downstream.

- **More homogeneous blend rates:** Designating that blending could only occur at an NTS offtake site could deliver a more homogeneous blend of hydrogen within a given region of the GDN, as gas flowing from an NTS offtake site should disperse more evenly across the GDN compared to gas input sites that are further downstream. This could feasibly lower any potential need for billing reform (as explored in Chapter 7).

- **Volumes and infrastructure costs:** As there is a greater volume of gas flow at higher pressure tiers of the GDN, this also means there is more capacity available to inject hydrogen upstream, such as at an NTS offtake site. This means that blending infrastructure investments at these locations could enable a greater amount of blending to occur per cost of investment compared to downstream blending infrastructure investments. Additionally, blending costs would likely be cheaper at NTS offtake sites where gas injection infrastructure already exists (see the Economic Analysis section for more details). Note however that designating locations where blending could occur may require additional costs for producers to transport hydrogen to reach those locations.

Despite these potential benefits, the strategic approach has limitations. We consider that the key limitation with the strategic approach is that it would prevent hydrogen producers from being able to input hydrogen into a GDN at locations other than those designated. This could benefit hydrogen producers seeking to blend that are located close to an NTS offtake site, for instance, and potentially limit hydrogen producers seeking to blend that are located elsewhere.

Work is ongoing to assess the most appropriate way to support blending, should blending be supported by government, in a way that best delivers blending's strategic objectives. As the strategic approach for the hydrogen blending technical delivery model could prevent some hydrogen producers from being able to blend based on their geographic location, there is a risk that this could unnecessarily limit the potential roll-out of blending.

We view this risk as outweighing the potential benefits of the strategic approach outlined above. Appropriate design of network capacity allocation within the free-market approach may help to realise any potential benefits of blending for a greater diversity of hydrogen producers, should blending be supported and enabled by government. Decisions relating to factors such as any injection point infrastructure costs could be made on an individual project basis, as is the case for existing arrangements for connections to the gas network.

Lead technical delivery model for hydrogen blending

Our lead option, based on evidence gathered and assessed to date, is to adopt the free-market approach, as described by the Gas Goes Green programme, as the preferred technical delivery model for hydrogen blending, should hydrogen blending be enabled by government. The free-market approach mimics the existing arrangements for connections to the gas network and would let the market decide where to inject hydrogen into the network. Theoretically, blending could occur wherever hydrogen producers apply to connect, which could be at any location and pressure tier across a GDN, thereby maximising the potential geographic extent of blending. It would be for the gas network operator to monitor hydrogen levels across their network to ensure a maximum hydrogen level is not breached, as they do for current gases in the GDNs.

Note the possibility that a review of blending safety evidence could suggest that blending is not suitable in specific regions of the GDNs. If this occurs, we will consider whether this could still align with the free-market approach and, if needed, consider an alternative technical delivery model.

Question 7. Do you agree with our lead option to adopt the free-market approach as the preferred technical delivery model for hydrogen blending, should blending be enabled by government? Please provide evidence to support your response.

We will continue to work closely with the GDN operators and wider industry to explore the most appropriate means to allocate capacity for hydrogen injections under the free market approach, should blending be enabled by government.

Question 8. If your project is considering connecting to a gas distribution network for the purposes of hydrogen blending, where would that connection be (in terms of geographic region and/or pressure tier on the network)? Please provide an indicative timeframe for when you may want to connect.

Chapter 7: Gas billing arrangements

Blending interactions with current gas billing calculations

UK gas bills are calculated based on the amount of energy a gas user consumes. This energy usage is shown in kilowatt hours (kWh) and is determined by both the quantity (or volume) of gas delivered to a gas user and the average energy content (or average calorific value) of that gas. The calorific value (CV) of a gas shows the amount of energy that is released when burning a certain volume of that gas. Therefore, if gas with a lower CV is delivered to a gas user, then a higher volume of that gas will need to be delivered to provide the same amount of energy, and vice versa.

Hydrogen has a CV of around one third that of natural gas. This means that around three times as much volume of hydrogen would need to be delivered to a gas user to provide the same energy as natural gas. Government is aiming to reach a decision on whether to support blending of up to 20% hydrogen by volume into GB gas distribution networks. Because of the lower CV of hydrogen, a blend of 20% hydrogen and 80% natural gas by volume would provide approximately 86% of the energy of 100% natural gas. Therefore, larger volumes of blended gas would need to be delivered to gas users to deliver the same energy as natural gas.

Because UK gas bills are calculated accounting for the CV of gas served, if larger volumes of blended gas are delivered to gas users to deliver the same energy as natural gas, then this should not impact the outcome of the billing calculation. Note that this assumes the blended hydrogen is sold at the same price as natural gas (as could be the case depending on whether/how blending is commercially supported by government) and note the broader potential costs of hydrogen blending (as explored in the Economic Analysis section of this consultation).

Also note that gas meters in the UK typically record the volume of gas delivered, often shown in cubic metres (m3) or cubic feet (ft3), as opposed to energy usage. This could cause gas customers to be concerned about higher meter readings if they are delivered hydrogen blended gas, although the final billable usage (in kWh) would also account for the lower CV of that gas.

Current Flow-Weighted Average Calorific Value (FWACV) gas billing framework

The current gas billing system calculates an average CV of gas across a region of the gas network known as a Local Distribution Zone (LDZ). This average CV is known as the Flow-Weighted Average Calorific Value (FWACV) and is determined using flow and CV measurements taken at different gas input points to the LDZ. By combining the FWACV with a metered volume of gas usage, a billable kWh can be calculated. This approach is determined by The Gas (Calculation of Thermal Energy) Regulations, under the responsibility of Ofgem.

To protect consumers, the FWACV for the whole LDZ is capped so that it can be no greater than 1MJ/m3 above the lowest CV of gas entering the LDZ. This cap ensures that consumers are billed using a FWACV that is no greater than 1 MJ/m3 above the actual CV of gas they received. This protects consumers who are located close to the injection site of a low CV gas from being overbilled for the energy content they receive. If a low CV gas is added to the LDZ and the FWACV is capped, then some energy usage across the LDZ would go underbilled (as overall energy usage would be calculated using a FWACV capped at a low level). To avoid this, gas network operators currently impose a minimum daily average CV to prevent a cap on the FWACV being imposed.

It can therefore be challenging to add low carbon gases that have a low CV, such as hydrogen, into gas networks under current billing arrangements without causing the FWACV to be capped. For example, biomethane, a low carbon natural gas substitute, has a CV of around 36.5 MJ/m3 compared to a typical FWACV of around 39 MJ/m3. As a result, biomethane may be 'enriched' with propane (a fossil fuel with a high CV) prior to injection into the gas network to ensure that its CV is no more than 1MJ/m3 below the FWACV.[18]

For the purposes of calculating whether a FWACV cap is required, the CVs of gases within an LDZ are normally measured at the entry point where they are injected into the gas networks. An alternative method is that the CV of commingled (essentially, blended) gas downstream of an injection point may be used to calculate whether a FWACV cap is required (so long as no consumers are supplied by the gas before it is commingled and so long as the input gas is compliant with the Gas Safety (Management) Regulations 1996 (GS(M)R). If this method is used, then this may reduce the need to bring the CVs of low carbon input gases in line with the FWACV prior to injection into the gas network, as essentially the input gas will be blended with the existing gas in the network before the resulting CV is used to calculate whether a FWACV cap is required.

Pure hydrogen has a CV of around 12 MJ/m3 and so could feasibly cap the FWACV at a very low level when injected into gas networks if not carefully managed. Even a 20% hydrogen blend has a CV of around 34 MJ/m3, which is not within 1MJ/m3 of a typical FWACV. The next section of this chapter explores how hydrogen blends of up to 20% by volume can potentially operate within current and/or future billing arrangements despite these challenges.

Future Billing Methodology Project

The Future Billing Methodology Project (FBM), conducted by industry (networks, consultants) and approved under Ofgem's Gas Network Innovation Competition funding, produced a report that provides options and recommendations on how the attribution of energy content (CV) for billing could be treated in a future with a wide variety of gas sources.[19] Its main objective was to investigate an efficient route to

[18] https://biomethane.northerngasnetworks.co.uk/wp-content/uploads/2015/11/NGN-Biomethane-Full-document-low-res.pdf (Accessed in September 2023)
[19] https://www.xoserve.com/media/43317/xos1434_xoserve-fbm-consultation-output-v7-final.pdf (Accessed in September 2023)

decarbonise heat whilst maintaining fair and equitable billing. It did not pre-judge the need for a new billing methodology, rather it investigated whether one may be required.

Between 2017 and 2021, the FBM conducted field trials around two biomethane injection sites. The purpose was to compare the results from field measurements (using oxygen tracking) with network modelling to determine whether network models can reliably simulate the travel and mixing of gases across the network and hence could be used to determine more localised CV zones for billing purposes.

The project concluded that the field trials sufficiently demonstrate that the zones of influence exerted by gas supplies onto the network fluctuate throughout the day and seasons, and that network models can reliably simulate the travel and mixing of gases under those varying demand conditions and thus predict CV at a more localised level.

We have assessed this work internally and our experts agree with its options and recommended approach.

Appraisal of Future Billing Methodology options

Utilising the insight gained from field trials and engagement with stakeholders, including via a consultation, the FBM identified and assessed five potential future billing options. They are outlined in the table below.

Table 1: Future Billing Methodology options

Option	Explanation
Option A: Working within existing frameworks	This is the least-change option. It focuses on controlled blending of low carbon gases within the existing Flow-Weighted Average Calorific Value (FWACV) framework set out by the existing Gas Calculation of Thermal Energy Regulations. Due to the lower CV of hydrogen blends compared to natural gas, blending of up to around 5% hydrogen could occur where the blend is a ‘minority energy flow’ (providing a low proportion of the total energy for an LDZ) so that the CV of the blended gas does not exceed 1MJ/m3 below the typical FWACV of an LDZ (which would cause the FWACV to be capped). However, as the hydrogen blend in proportion to the overall energy flow within an LDZ increases, then this may reduce the FWACV to the extent that the percentage of hydrogen within the blend can be further increased without causing the FWACV to be capped. The FBM notes that blends of up to 20% hydrogen could feasibly be enabled within the current FWACV framework, however, only in LDZ networks with access to a significant supply of hydrogen at multiple input points.

	This option would not remove but may reduce the need for propane enrichment of biomethane, should hydrogen blending lower the FWACV for an LDZ where biomethane is also input. This option may require enhanced monitoring and control, with associated costs, and gas network operators would continue to be responsible for this. *FBM estimated implementation costs at 2021-22 prices:* Initial cost - £5.5 million Ongoing costs - £0.5 million per year *FBM estimated earliest implementation date:* 2023 *FBM recommendation:* This option should be implemented. It could be an early route to decarbonise the gas distribution networks without need for changes to gas billing systems and regulations. It could be a long-term solution or used while option(s) that require billing reform are developed.
Option B: Embedded Zone Charging	This option uses network modelling to create separate charging areas around low CV gas input points within an LDZ. Gas users within such a charging area would be billed accounting for the CV of that low carbon gas supply. Gas users that are not in such a charging area would continue to be billed based on the FWACV of other input gases to the LDZ. This could enable hydrogen blends of up to 20% by volume on a 'minority energy flow' basis and could also enable biomethane to be injected without need for propane enrichment. Allocation of gas users to separate charging areas could be done via typified bill-impact analysis or CV modelling at a specific demand level. The report sets out that, whilst zones of influence can be reliably simulated, there are several other factors, such as low carbon gas production outages, inconsistent supply, and maintenance work that could impact on the embedded zone and would need to be considered. Allocating a customer to an embedded zone also remains complex. Neither a typified bill analysis nor utilising a demand level is without risk as they both risk un-allocating energy and over/underbilling some customers. The report also concluded that this option would require changes to the gas thermal energy regulations.

	FBM estimated implementation costs at 2021-22 prices: Initial cost - £162.5 million Ongoing costs - £2.4 million per year *FBM estimated earliest implementation date:* 2026 *FBM recommendation:* Development of this option should be explored, but Option C should be prioritised ahead of this, as Option C requires comparable cost and effort with a greater degree of benefits.
Option C: Online CV Modelling	This option would use measured CV at all gas input points, alongside live data from the local transmission system, to inform detailed modelling of output CVs at gas meter point level across the LDZ. The report estimates that up to 500 extra CV Determination Devices (CVDDs) would need to be installed for verification. This option could provide a consistent method for billing across the range of potential gas transition scenarios. This could enable hydrogen blends of up to 20% by volume on a ‘minority energy flow’ basis and could also enable biomethane to be injected without need for propane enrichment. It may also improve the attribution of billable CVs to gas users in comparison to the existing FWACV billing arrangements. It would require the use of additional software with streamlining and automation of certain processes. Organisations across the gas industry would need to invest in significant system development to transition. Regulations do not currently allow different CV models to operate within the same LDZ, which means regulations would likely need to change to make this option viable. *FBM estimated implementation costs at 2021-22 prices:* Initial cost - £189.2 million Ongoing costs - £5.4 million per year *FBM estimated earliest implementation date:* 2027

	FBM recommendation: A feasibility study for this option should be commenced in parallel to implementation of Option A. This option could deliver one consistent methodology to enable a range of potential gas transition scenarios and could help deliver the benefits of biomethane and hydrogen blending at greater scale.
Option D: Zonal CV measurement	This option builds on Option B and would involve breaking the entire LDZ into physical zones using strategically placed CVDDs. Meter points in each zone would be allocated to a specific CVDD for billing. The report estimates that up to 10,000 extra CVDDs would need to be installed across a single LDZ. The technological readiness of CVDDs, installation, maintenance, power supply (each device requiring land access rights) and data communication pose significant potential challenges. *FBM estimated implementation costs at 2021-22 prices:* Initial cost - £500.6 million Ongoing costs - £7.0 million per year *FBM estimated earliest implementation date:* 2030 *FBM recommendation:* This option is not recommended due to the high cost and complexity associated with using CVDD technology at this scale.
Option E: Local CV Measurement	This option is an extension of Options B and D and would install CVDDs at local level throughout the LDZ. They could potentially be linked to point of use (e.g., a property's smart meter) to ensure each customer pays for the CV of gas they directly receive. The report estimates that up to 44,000 extra CVDDs would need to be installed across a single LDZ. As with Option D, the technological readiness of CVDDs, installation, maintenance, power supply (each device requiring land access rights) and data communication pose significant potential challenges. *FBM estimated implementation costs at 2021-22 prices:* Initial cost - £909.6 million

	Ongoing costs - £16.7 million per year *FBM estimated earliest implementation date:* 2035 *FBM recommendation:* This option is not recommended due to the high cost and complexity associated with using CVDD technology at this scale.

The main recommendations from the FBM are that both Option A and Option C are taken forward. A short summary is below.

- Significant amounts of hydrogen blending can be achieved under the existing billing regulations (Option A), which is the lowest cost and quickest to implement option. This may not be limited to around 5% hydrogen blending by volume in practice – higher blends of up to 20% by volume could potentially be facilitated in LDZs with access to a significant supply of hydrogen at multiple input points. In a situation where a limit of around 5% hydrogen by volume is required, it would still mean around 9TWh of hydrogen could be blended annually.[20]
- The FBM recommends that a feasibility study into the concept of online CV modelling for billing (Option C) should be undertaken to further understand cost, timescales and benefits, but notes that this is not a pre-requisite for hydrogen blending. The timescales to deliver the feasibility analysis and subsequently introduce operational changes make this a medium to long term option.

In practice this would mean Option A is adopted in the initial years of hydrogen blending, should blending be enabled by government, whilst Option C may be investigated further over a more suitable timeline.

Lead option for blending gas billing arrangements

Our lead option, based on evidence gathered and assessed to date, would be to adopt Option A (working within existing frameworks) from the Future Billing Methodology Report as the preferred approach to billing, should hydrogen blending be enabled. In practice, this option should not require immediate changes to the existing gas billing methodology. This should ensure that the pace of rollout for hydrogen blending, if it is enabled by government, is not delayed by a need for changes to billing arrangements.

[20] Note that if gas consumption falls and the volume of gas in the network decreases, the amount of hydrogen that can be blended would also decrease.

Although hydrogen blending under Option A would likely limit the permitted level of hydrogen blending to be below 20% by volume across the GB gas distribution networks in practice (to ensure that variations in gas CV are maintained within current regulatory limits and ensure fairness for consumers), we do not view this as being incompatible with our strategic objectives for blending (as outlined in Chapter 3).

We assess that a decision on whether to undertake a feasibility study into the concept of online CV modelling for billing (Option C) can be taken separately to a policy decision on hydrogen blending. We do not intend to announce further details on this option as part of our intended policy decision in 2023.

Question 9. Do you agree with our lead option to adopt Option A (working within existing frameworks) from the Future Billing Methodology Report as the preferred approach to gas billing, should blending be enabled by government? Please provide evidence to support your response.

Blending interactions with gas meters

As part of the HyDeploy project, the TÜV SÜD National Engineering Laboratory carried out a test programme to determine the accuracy of a sample of domestic and industrial gas meters when receiving hydrogen blends of up to 20% by volume. The resulting report, which indicates that gas meter performance and accuracy with hydrogen blends of up to 20% by volume may be comparable to their operation with natural gas, will be submitted to and assessed by government, including as part of the wider hydrogen blending safety review. Should any modifications or cost requirements be identified as necessary to ensure that gas meters can perform within operational limits when receiving hydrogen blends of up to 20% by volume, this would be factored into the economic assessment of blending.

Economic analysis

Context

This economic analysis is based on current evidence to help inform a strategic policy decision on whether to support blending of up to 20% hydrogen by volume into GB gas distribution networks. As blending trials progress and safety evidence is reviewed, further costs may be revealed. Subject to the outcomes of the safety review, the Health and Safety Executive (HSE) may consult on amendments to the Gas Safety (Management) Regulations 1996 (GS(M)R). An Impact Assessment, and cost benefit analysis, would be completed alongside this. The costs and benefits associated with blending will therefore be considered again in the future and may include additional evidence, if revealed through the safety review.

A positive strategic decision on blending would not predetermine that any hydrogen is produced for blending, or that any costs associated with blending will be incurred. In addition to being dependent on the safety case, and the policy design of potential government support (see Chapter 4 for details), there are many future decision points where the government will have control over whether a project may receive support for hydrogen produced for blending. As set out in Chapter 3 of this consultation, blending may only have a limited and temporary role and should only be supported in so far as it supports hydrogen economy development without ‘crowding out’ other end user sectors. If hydrogen is blended into the gas network, this would displace natural gas use and contribute to reducing emissions. However, it is not the intention that the maximum amount of hydrogen (e.g. up to 20% by volume) is produced for blending so that blending contributes the maximum to emissions savings, as this is not a strategic objective for blending. Additionally, the analysis in this chapter does not suggest that a specific amount of hydrogen should be produced for blending. The opposite is true, if a positive strategic decision is made, the implementation will be dependent on specific use cases and should maintain optionality and flexibility.

Even if there is a positive decision to enable blending, and if production projects can apply to receive government subsidy support for blended volumes and amendments to the GS(M)R are made, it is possible that no blending will occur. If demand and hydrogen transport and storage infrastructure develop and production plants secure consistent and reliable offtakers, volume risk may not present a problem. Even if blended volumes turn out to be very low, it may still be beneficial to make a positive decision to support blending. By having blending as a reserve offtaker in the event that offtaker demand falls away, there is the potential for financing and therefore subsidy costs for all projects to be lowered, even if no volume risk materialises and no projects use blending as a reserve offtaker. This is discussed in more detail later in this section.

The corresponding analytical annex provides more detail on the economic analysis, including descriptive case studies and non-monetised benefits, costs, and risks. The annex also includes sensitivity analysis on the quantitative analysis presented in this section, and a description of the method and assumptions.

Rationale for blending

Based on evidence to date, our working assumptions on the potential benefits of blending, described throughout this section, are driven by two technoeconomic characteristics of blending:

- Firstly, blending can act as a flexible, reserve offtaker as the network can receive variable blends of hydrogen up to 20% by volume.
- Secondly, based on evidence to date, the main additional costs necessary to allow blending are costs associated with building injection point infrastructure. The amount of injection point infrastructure needed will increase as amounts of hydrogen produced for blending increase. Evidence to date indicates that there is a relatively low one-off upfront cost necessary for billing (billing costs are discussed in Chapter 7 and later in this section). Note that further upfront costs could be identified by the review of blending safety evidence (as discussed in Chapter 2), such as if physical changes to the gas network are required ahead of blending.

If we consider volume risk from a producer's perspective, there are two main circumstances where a plant may need a reserve offtaker, like blending, to overcome volume risk.

- Blending may be able to play a role in managing the risk of hydrogen producers being unable to sell enough volumes of hydrogen, for example, if an offtaker (e.g. an industrial facility) is no longer able to buy hydrogen from the plant, impacting the production project's revenue.
- Blending may also help to mitigate volume risks relating to the development of hydrogen transport and storage infrastructure, for example if an infrastructure project is delayed.

In the short term, limited storage supported via the HPBM has some potential to help mitigate volume risk. In the longer-term we envisage that the availability of larger-scale storage and the liquidity of the market may help mitigate volume risk further. However, larger-scale storage has long-lead times for development, and we do not currently expect larger-scale facilities to be in operation until the late 2020s, or early 2030s. Exports could also have a role to play in mitigating volume risk. However, for hydrogen to be exported, hydrogen transportation and storage infrastructure will also be needed and the HPBM, for example, does not subsidise export volumes. Storage and exports are therefore not likely to be able to offer the benefits blending could provide in managing the examples of volume risk described above in the early years of the hydrogen economy. As described in Chapter 3, in addition to mitigating volume risk, blending may also have value in enabling electrolytic hydrogen producers to support the wider energy system. This could be beneficial for electrolytic hydrogen producers located behind electricity network constraints using excess renewable electricity that would otherwise have been curtailed, for instance.

Supporting certain types of projects may provide more benefits and pose fewer risks compared to other uses of blending by production plants. Future work will need to consider the potential value in supporting different categories of production projects.

This will depend on the types of production projects that come forward, the severity of volume risk these plants face and their potential to mitigate network constraints. For any benefits of blending to be realised, this may be dependent on potential government support to be designed in such a way that blending is a transitional offtaker and is only available for projects where blending provides sufficient benefits.

Whether blending could be beneficial for a project will depend on a range of factors, including the planned location, the availability of hydrogen transportation to reach appropriate injection points on the gas network, and the distance to those injection points. Even for projects which do face some volume risk, blending may not be economically viable if a production plant is located far from an injection point, or where the costs of injection point infrastructure are high.

Cost assessment

Using the evidence to date, we have identified four categories of blending costs. How these categories of costs could be funded is subject to this consultation, and further policy design work.[21]

- The costs of producing hydrogen to be blended.
- The costs of any transport and storage infrastructure necessary to link the producers and offtaker – a gas network injection site, in the case of blending.
- The costs of any infrastructure to inject hydrogen into the gas network for blending.
- Costs to the networks to enable blending (e.g., billing reform, monitoring of blends).

Based on evidence to date, for blending to be implemented there is some infrastructure necessary to allow accurate billing, described in more detail in Chapter 7. In this analysis, the costs associated with Option A are considered[22] and most of these costs are included in the injection site infrastructure costs, described in Table 3 later in this section. In addition to those costs included in the injection site costs, there is an upfront, one-off system cost of around £300,000 necessary to blend hydrogen within existing frameworks.[23]

This economic analysis is based on current evidence to inform a strategic policy decision in 2023. As trials progress and government completes a safety review of blending, further costs may be identified. It is not currently feasible to quantify theoretical additional costs or say that, for instance, if additional potential costs are

[21] This analysis assumes that the Gas Safety (Management) Regulations 1996 (GS(M)R) are amended and there are therefore no costs of going through a blending GS(M)R exemption request process.
[22] The costs associated with Option C have not been included in the analysis in this chapter as Option C is not necessary to enable blending, and the decision on whether to undertake a feasibility study into this option will be taken separately to a policy decision on hydrogen blending. Please refer to Chapter 7 for more details.
[23] This figure is based on evidence provided by the gas networks.

below a certain level, then blending could still offer value for money. Work is ongoing to explore three potential categories of costs that may be necessary to enable blending. The evidence at the moment is inconclusive and these costs have therefore not been included in the analysis.

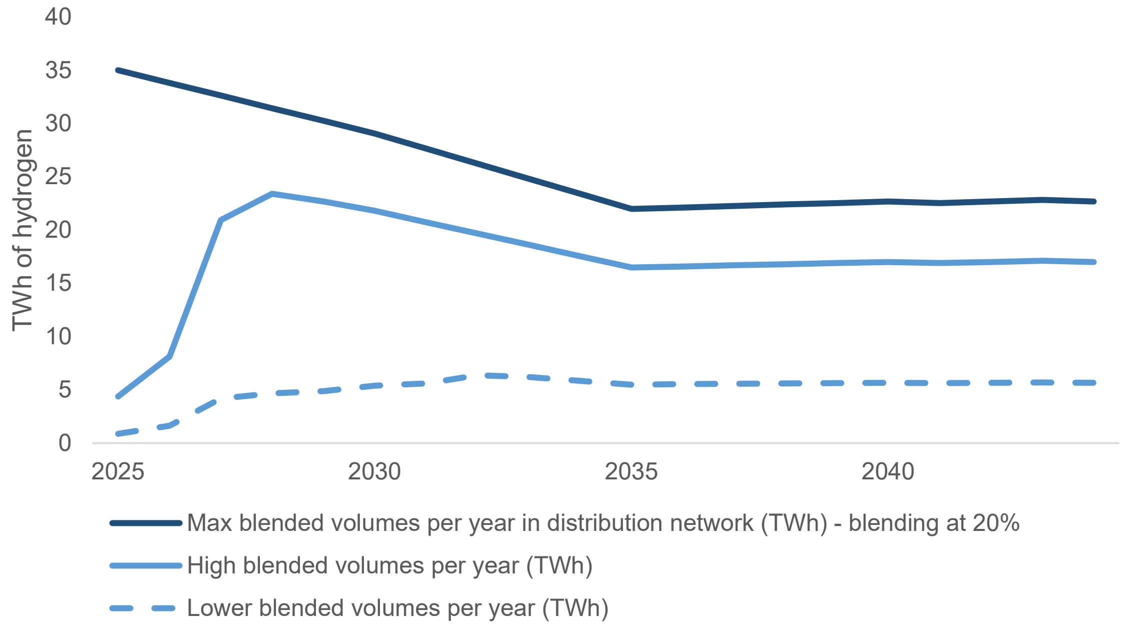
1. There could be costs to users if they are not able to receive blended gas – whether this is a safety or operational risk. For example, there may be costs associated with deblending if users cannot use blended volumes of gas and need to de-blend hydrogen at the point of use. The Hydeploy trials have been gathering evidence to test the safety of blends on industrial users and we have not received any evidence to date that mitigations such as deblending are necessary for industrial users connected to the gas distribution network. However, this consultation seeks to further understand the potential impact of receiving variable hydrogen blends of up to 20% hydrogen by volume on industrial users connected to the existing gas distribution network such as power generators. Through Question 1 in this consultation, we would like to understand if any mitigations may be required such as deblending.

2. Another potential cost is the cost of updating some legacy gas meters that may not be able to work with blended volumes of gas within acceptable accuracy tolerances. It is not currently clear whether costs may be required to address interactions between blending and legacy gas meters, so this has not been included in this analysis.

3. Some areas of the GB gas distribution network are made of old iron main which can be subject to embrittlement by hydrogen. The Iron Mains Risk Reduction Programme already addresses the replacement of 'at risk' iron gas mains as these pipes can crack and be a gas leakage risk. This programme intends to have replaced all pipes by 2030. If blending is to be rolled out nationally from 2025, premature replacement of pipe and equipment may be necessary, ahead of the current programme. However, before government have completed the safety assessment, we do not know what the directive will be regarding the iron mains risk for hydrogen blending. A potential outcome is that hydrogen can only be blended into areas of the distribution network where the pipes and components (for example, valves etc.) are not made from old iron. In this instance, it is likely that in the early years blending would only act as a flexible offtaker in specific parts of the GB gas distribution networks rather than blending being the driver to accelerate the iron mains replacement programme. As stated throughout this chapter, whether blending offers value for money will be considered on a project-by-project basis. This will depend on the specifics of the production plants operation and location and may depend on its proximity to an area of the gas distribution network with modern pipes.

High and lower blended volume scenarios

Figure 1: High and lower blended volumes scenario, compared to the maximum blended volumes - 2025 to 2045



As set out in Chapter 2, any policy decision in 2023 would be a strategic decision on whether to support blending of up to 20% hydrogen by volume into GB gas distribution networks. In this cost assessment, for the high scenario, we assume high blended volumes are 15%, rather than the maximum of 20%. This is because if we are blending at 20% then blending would no longer be a flexible offtaker. 5% less than the maximum is an illustrative assumption as there is currently no evidence on the volumes of hydrogen that could be blended whilst still maintaining flexibility. This will be dependent on the location of production projects and the injection sites used. To blend at 20%, consistent blends would need maintaining and storage infrastructure will likely be needed. If blending is to fulfil its strategic role, flexibility is key. In a high blending scenario, we would not be reaching high blend rates of 15% initially as this is higher than total low carbon hydrogen supply estimates. We have assumed 50% of estimated low carbon hydrogen production is blended up to a maximum of 15%.[24] In this scenario, between 2025 and 2028, 50% of hydrogen produced is blended and from 2029 onwards 50% of hydrogen production would exceed the 15% cap, so the high blended scenario is equivalent to 15% blends from 2029 onwards. In the lower scenario the maximum blending rate achieved is 5% and 10% of hydrogen produced is blended up to the 5% cap. Like the 15% cap in the high scenario, 5% is an illustrative assumption for the lower scenario. However, based on data from the Department for Energy Security and Net Zero's current market intelligence, a plausible low scenario could be zero volumes of blending.

[24] This is an average across the whole grid but a higher proportion of estimated hydrogen production could be blended in some locations. 50% is an illustrative assumption to derive a high scenario for blended volumes and should not be interpreted as a prediction of how much we expect projects to blend.

As there is insufficient project data available to build up reasonable assumptions for a trajectory of potential blended volumes, these assumptions are illustrative but capture a potential range for the volume of hydrogen that could be blended.

Injection site costs

Hydrogen could be injected at various points in the gas distribution network, and there are pros and cons of using different locations. The three models for injection into the gas distribution network are presented in the table below and are described further in Chapter 6. The Energy Network Association's Gas Goes Green project produced a functional specification for injection points. The project provided three case studies and associated indicative costs to the Department. These costs are estimates and the actual costs per site will vary.

Table 2: Models for injection into the GB gas distribution networks

Type of hydrogen injection site	Description of site	Costs (£, in 2021 prices)	Capacity (hydrogen energy – MWh/yr)	Capacity and cost comparison
Hydrogen injection at a National Transmission System (NTS) offtake site	Injection point furthest 'upstream' on the gas distribution network – these are sites where the NTS branches into the gas distribution network where there is already infrastructure	CAPEX - £2,503,000 OPEX – £37,500	2,794,000	These injection points have the highest capacity – the modelled hydrogen energy these sites can receive is 75 times more than the hydrogen energy the two alternative sites can receive. The capital costs for this type of site are around double the costs of an LDZ PRS site, as slightly more construction is needed for a higher volume injection point. The costs are 75% of the costs of a Greenfield site because most of the infrastructure is already present.
Hydrogen injection within Local Distribution Zones (LDZ) Pressure Reduction Site (PRS)	Injection point 'midway' in the gas distribution network – these are sites where there is already infrastructure	CAPEX - £1,025,000 OPEX – £37,500	37,000	LDZ and Greenfield injection sites have the same capacity, but LDZ sites are three times cheaper as there is already infrastructure on site, reducing the construction costs.
Hydrogen injection at a Greenfield site	Injection point furthest 'downstream' on the gas distribution network – these are sites where there is no infrastructure already	CAPEX - £3,340,000 OPEX – £37,500	37,000	

Although it costs less to blend further 'upstream' on the network, there are fewer potential locations so if a production plant is located far away from a cheaper injection site, it could be more cost-effective to blend further 'downstream' on the network to reduce transportation costs. Chapter 6 has more details on injection sites and technical delivery models and presents the lead option that blending would be implemented so that hydrogen could be injected at any suitable injection point. This would mean that individual production projects may be able to choose the most efficient injection point for their operation, based on the specific costs for that project.

The following analysis assumes a set amount of hydrogen is produced. The production volume scenarios are the high and lower volumes described in Figure 1, above. The production costs are an estimate of the total cost of producing, transporting, and storing those volumes of hydrogen. The blending infrastructure costs use the estimates for injection sites costs in Table 2, above, to calculate how much it could cost for the injection points necessary to inject the corresponding volumes of hydrogen. These costs also include the upfront cost necessary for billing. The method to derive these costs are described in the Annex of this consultation. In addition, the sensitivity analysis in the Annex outlines the impact on this analysis of changing production and injection site costs.

Table 3: Estimated production, transport, storage and blending infrastructure costs in two production volume scenarios (£m, 2021 prices, rounded to the nearest £10m)

	Production, transport, and storage costs	**Blending infrastructure costs**	**Infrastructure costs as % of production, transport and storage costs**
High production volume scenario	£29,120	£840	2.9%
Lower production volume scenario	£8,290	£200	2.4%

The total estimated blending infrastructure costs are 2.4-2.9% of the estimated costs of producing, transporting, and storing the total hydrogen volumes in the high and lower production volume scenario. Therefore, based on this analysis and assumptions, if blending lowers production, transport, and storage costs by around 2.4-2.9% then blending could offer value for money compared to the counterfactual, where the counterfactual is producing hydrogen but not allowing any volumes to be blended. This analysis makes the following implicit assumptions:

- The sales value of blended volumes of hydrogen is the same as the sales value of hydrogen for other offtakers.
- The monetised benefits per unit of hydrogen produced for blending – greenhouse gas emission savings and air quality benefits – are the same as the benefits per unit of hydrogen produced for other offtakers.
- The transport and storage costs necessary to produce hydrogen and inject this into the gas network for blending are the same as the transport and storage costs needed for alternative offtakers.

Depending on the potential policy design and the fuel types that might be displaced by producing hydrogen for offtakers other than blending, the first two assumptions may not always apply but are pragmatic for this analysis. The transport and storage costs that may be necessary for blending will be higher than the costs for alternative offtakers for some projects, and lower for others. There is insufficient evidence to make an overall assessment about whether transport and storage costs for hydrogen produced for blending would be higher or lower, and this assumption is therefore reasonable for this analysis.

The production volume inputs are illustrative amounts, indicating the theoretical amounts of hydrogen production that could be blended. This analysis does not imply that we would need to blend these volumes of hydrogen nationally, at a cost that is around 3% lower than producing hydrogen for use elsewhere, for blending to potentially offer value for money. As discussed in the financing risk section, blending has the potential to lower production costs even if no hydrogen is ever blended.

The estimated costs in this analysis are very uncertain. Actual costs will depend on the design of any potential government support for blending, and the growth of the hydrogen economy. In addition, the production, transport, and storage cost estimates may be improved as we gather more evidence on potential costs, especially from projects applying for the first rounds of HPBM support. Because of this uncertainty, it is not possible to calculate the total reduction in production costs that blending may lead to. However, as the injection point costs are relatively low, and blending may lead to some cost savings, we assess that blending has the potential to contribute to a reduction in production costs that is greater than blending infrastructure costs, either at a system level, or on a project-by-project basis. Providing the optionality for projects to blend could therefore be favourable overall.

Financing risk

Currently, hydrogen production projects do not have an offtaker of last resort and if volumes sold fall to zero, plants would receive no subsidy support. Blending could make some projects more investable as it reduces volume risk (where an offtaker can no longer purchase hydrogen from the producer). Whether blending is a viable reserve offtaker for a specific project will depend on the characteristics of individual projects, for example, their location and proximity to injection sites. If blending can lower investment risk, this may reduce the financing for production projects, and in turn reduce the commercial support required as government takes on less risk.

The electricity Contracts for Difference subsidy scheme introduced an offtaker of last resort mechanism with a similar objective to the potential strategic role of blending as a reserve offtaker. It provided eligible generators with a guaranteed ‘backstop’ route-to-market where the price was set to ensure it was a genuine last resort. The purpose was to provide comfort to lenders and investors and aimed to reduce the cost of investment in electricity, boost competition amongst generators and offtakers, and lower the costs of government subsidy, and therefore costs to consumers. There have been no applications to the offtaker of last resort scheme since its launch. This should not be interpreted as the scheme not working. Just by being in place, the offtaker of last resort policy is likely to have reduced the cost of investment by lowering risks. Although we don’t have the evidence to quantify, for instance, how much the Weighted Average Cost of Capital (WACC)[25] for hydrogen production may reduce by, there is the potential that risks will be lowered, and therefore costs reduced, without any costs associated with blending being incurred.

[25] The WACC is the amount of money a company needs to pay to finance its operations.

As described in the cost assessment section above, if blending reduces production, transport, and storage costs by between around 2.4-2.9% (see Table 3 in the cost assessment section above) then this would offset the additional costs necessary for blending infrastructure. Making a positive decision on blending and providing support for blended volumes could offer benefits even if no, or very little, hydrogen is ever blended. Depending on the policy design, the benefits of lower financing risk may be realised even if no hydrogen injection infrastructure is built, but projects had the option to finance this if they needed a reserve offtaker. Alternatively, a project could finance construction of an injection point site to be ready for the start of their operation. This could act as an insurance policy so projects had the option of blending hydrogen, but the insurance policy may never be invoked if a plant did not face volume risk. These scenarios are illustrative and whether costs can be recovered will depend on the design of any potential support. If blending is not a viable reserve offtaker, for example there is no suitable transportation, then the effect on lowering financing risks will be less.

There are other commercial-based solutions to managing volume risks for hydrogen producers, for example, the HPBM sliding scale and take-or-pay agreements.[26] However, these may reduce the volumes of hydrogen produced and increase the cost of government support per unit of hydrogen sold. A potential benefit of blending is that if utilised, this would mean low carbon hydrogen is being produced and used to displace fossil fuels.

Production, transport, and storage costs

The costs in Table 3 include production, transport, and storage costs. Because blending could be a flexible offtaker, hydrogen produced for blending may not require as much storage infrastructure as is needed for offtakers with fluctuating operating patterns that misalign with hydrogen supply. The transportation costs needed for hydrogen produced for blending could be more or less than transport costs for other offtakers and this would depend on the location of potential injection sites and the infrastructure needed for a producer's other potential offtakers. The impacts of blending on potential government support, which would make up a portion of the production, transport, and storage costs, will depend on the design of potential support and the specific use cases supported.

By mitigating for volume risk, blending could enable plants to maintain their production profiles, potentially reducing production costs per MWh of hydrogen produced. An increase in load factors, compared to ramping down, decreases the levelised cost of hydrogen,[27] as the capital and fixed operational costs are spread over a larger volume of hydrogen output. Blending a proportion of hydrogen produced incurs additional costs to cover blending infrastructure costs and, depending on the change in load factors, blending infrastructure costs may be outweighed by the reduction in production costs. As discussed in the volume risk section, demand volatility, caused by expected and unexpected offtaker outages – both short and longer term – can negatively impact a project's revenue. While storage infrastructure could help with this, the availability of larger-scale storage (or transport to connect across regions) will not be available in the short term. Blending can therefore help provide an offtaker of last resort to a producer.

Question 10. We welcome feedback on the economic analysis presented in this section and corresponding annex. Please provide evidence to support your response.

[26] With a take-or-pay agreement, the buyer is obliged to either take an agreed amount of commodity from a seller or pay a penalty if it cannot take the commodity.
[27] The Levelised Cost of Hydrogen (LCOH) is the discounted lifetime cost of building and operating a production asset, expressed as a cost per energy unit of hydrogen produced (£/MWh).

Consultation questions

1. a) Do you have any concerns around the safety or usability of hydrogen blends of up to 20% by volume in the GB gas distribution networks?

   b) If so, is this dependent on whether the blend is a fixed or variable percentage (up to 20% by volume)?

   c) If applicable for your project, do you anticipate any cost impact to your business (e.g. from replacing equipment, adjusting production levels or requiring deblending equipment and processes)?

   d) If applicable, how long would you require to prepare your facilities to accept fixed or variable hydrogen blends? Would there be a substantive difference depending on whether the blend is a fixed or variable percentage?

   e) Please provide supporting evidence about any impacts you may expect and estimates for the costs of mitigation, if applicable.

2. Do you have any additional views or concerns associated with blending hydrogen into GB gas transmission networks that have not been identified within this chapter? Please provide evidence to support your response.

3. Do you have any comments on our views of the strategic role of blending, as described in this chapter? Please provide evidence to support your response.

4. Do you agree that, if blending is enabled and commercially supported by government, the most appropriate mechanism would be via the Hydrogen Production Business Model? Please provide evidence to support your response.

5. Do you agree with the proposed lead option to allow both gas distribution network operators and gas shippers to purchase hydrogen produced for blending? Please provide evidence to support your response.

6. Given blending's proposed strategic role as a reserve offtaker, do you agree that certificates for low carbon hydrogen injected into the gas network should be precluded from onward sale after the point of injection? Please provide evidence to support your response.

7. Do you agree with our lead option to adopt the free-market approach as the preferred technical delivery model for hydrogen blending, should blending be enabled by government? Please provide evidence to support your response.

8. If your project is considering connecting to a gas distribution network for the purposes of hydrogen blending, where would that connection be (in terms of geographic region and/or pressure tier on the network)? Please provide an indicative timeframe for when you may want to connect.

9. Do you agree with our lead option to adopt Option A (working within existing frameworks) from the Future Billing Methodology Report as the preferred approach to gas billing, should blending be enabled by government? Please provide evidence to support your response.

10. We welcome feedback on the economic analysis presented in this section and corresponding annex. Please provide evidence to support your response.

Next steps

The purpose of this consultation is to further understand the potential strategic and economic value of blending and to seek feedback on lead options for the potential implementation of blending, if blending is supported and enabled by government. This will help to ensure that hydrogen blending policy development accounts for stakeholder feedback and relevant considerations to best meet the policy objectives set out in this consultation.

This consultation will be open for six weeks closing on 27 October 2023. The Department for Energy Security and Net Zero will analyse all responses and address any relevant points made by stakeholders to ensure we can fully achieve our policy aims.

On-going engagement will form an important part of our work. We intend to continue to engage with stakeholders such as through working groups and bilateral meetings.

Analytical Annex

Case studies

The following case studies describe two illustrative projects where blending may be beneficial. In these case studies, we assume the projects receive support through the HPBM, the lead option described in Chapter 4, to provide a more detailed description. Potential subsidy support is however subject to consultation and further policy design. The first case study (Producer X) describes a project where blending acts as a reserve offtaker, while the second case study (Producer Y) describes a project where blending acts as a strategic enabler for electricity system balancing.

Producer X is an electrolytic production plant which receives a HPBM contract and has an estimated operational date in the mid-2020s, with a predicted load factor of 60%. Producer X has secured hydrogen offtakers in industry, transport, or power for 100% of their projected production volumes and has an above ground storage tank to manage some mismatches in supply and demand. Two years into operation, an industrial site which uses 30% of the hydrogen produced by the plant, goes bankrupt. The production plant manages to find an alternative offtaker, but this takes over two years as the new site needs to upgrade its equipment to be hydrogen ready. During these 2 years, the production plant blends 30% of its production volumes into the gas distribution network.[28]

Injection point infrastructure will be needed, and if this project is in a dense industrial area, it is more likely that there is a suitable injection point close by. This injection point may already be receiving hydrogen injections from other production plants in the area, thereby lowering the costs for injection. The hydrogen will also need to be diverted to an injection site. If the project is already planning to supply hydrogen to offtakers via a virtual pipeline, for example by trucking, these trucks could be utilised to transport hydrogen to an injection point. The flexibility of blending means hydrogen can be produced for blending over different time periods. In this example, the project could blend hydrogen for two years before an alternative offtaker comes online and depending on the availability of injection site infrastructure and transportation, could blend hydrogen for e.g., a few months if a different offtaker needs to shut down for an extended period due to technical issues. The HPBM sliding scale minimises the volume risk faced by production plants. However, this only applies when sales volumes fall below a certain level after a qualifying event. Assuming that is 50%, then if 30% of a plant's sales fall away, the sliding scale cannot be relied on. Alongside the sliding scale, blending could therefore also reduce financing risks.[29] In this case study, hydrogen production capacity which has been subsidised and built is utilised, with the hydrogen displacing fossil fuel alternatives. If the production plant can minimise the need to ramp down, this could also reduce the risk of equipment damage and therefore maintenance costs.

If offtakers go offline, and sales volumes reduce by around 30%, for example, the payments made by government to the producer will decrease. Therefore, because blending enables the producer to continue to sell volumes of hydrogen, the costs to

[28] The Low Carbon Hydrogen Agreement (LCHA) has a production cap to limit the volumes of hydrogen produced by a plant in receipt of HPBM support: https://www.gov.uk/government/publications/hydrogen-production-business-model. If blending is supported through the HPBM, the cap mechanism could provide a limit on the amount of hydrogen which a plant could produce to be blended.
[29] This is described further in the economic analysis section of this consultation.

government could be higher even if the overall costs per unit of hydrogen produced are lower, because the payments will not fall as production profiles are maintained, despite the loss of offtaker. If a higher proportion of a producer's planned offtake is reduced, and this falls below the threshold for the sliding scale, instead of invoking payments through the sliding scale mechanism, the plant could receive support for the blended volumes, meaning the government is subsidising hydrogen production, use and carbon abatement, rather than paying higher amounts through the sliding scale for less hydrogen production, use and carbon abatement. The effect of blending on potential government support costs will depend on its potential interaction with the sliding scale, and the level at which this is set.

A moral hazard in this case study is that supporting blending could disincentivise production plants from finding new offtakers. If a decision is made for blending to be supported by the HPBM, detailed policy design work would be required to mitigate this risk. This case study is therefore illustrative and does not indicate any decision about the appropriateness of any support option or its design.

Producer Y is an electrolytic hydrogen production project in its early concept stages, planning to locate in Northeast Scotland, and connect to an offshore wind farm to produce hydrogen from electricity that would otherwise be curtailed.[30] If this project goes ahead, the estimated operational date is in 2030. Unlike the other case study described above, which is further developed with definite offtakers and has received HPBM funding, this project does not have definite offtakers. Producer Y, like many other early concept projects, has a barrier of volume risk stemming from uncertainties around future hydrogen transport and storage infrastructure and at scale adoption of hydrogen. Its commercial case relies on blending being its only (or majority) offtaker before larger-scale transport and storage infrastructure opens new markets for the producer.

If Producer Y has certainty that it is eligible to participate in a Hydrogen Allocation Round with blending as a majority offtaker, because of its location and potential role in mitigating network constraints, Producer Y could become a commercially viable project and secure financing. If the project is awarded a Low Carbon Hydrogen Agreement, this could drive potential offtakers in the vicinity to switch to hydrogen as certainty of supply is now guaranteed, because blending has provided revenue certainty. For example, hydrogen use for road transport could emerge because supply is more certain. As a result, when the plant does become operational, a portion of the offtake could be used by end users in e.g. transport, power, and industry, while the remaining production volumes are blended. Hydrogen transportation and storage infrastructure is likely to grow most in the 2030s, meaning that new offtake markets could become available for Producer Y. The hydrogen produced for blending from Producer Y could then be phased out and all the hydrogen supply from this project could be injected into 100% transportation infrastructure for a range of end users which are further afield from the producer's location.

[30] Curtailment is a purposeful reduction in electricity output and occurs for two main reasons: oversupply, where there is not enough demand for the electricity produced e.g. due to high wind speeds, or transmission constraints, where there is not enough transmission infrastructure to transport the electricity to useful demand.

Supporting this plant would enable the build of hydrogen production capacity and if the project mitigated network constraints,[31] this could reduce curtailment payments. However, there is no guarantee of future hydrogen offtakers and uncertainty remains around the pace and scale of transport infrastructure development. Therefore, in this case study, if 100% hydrogen transportation infrastructure isn't developed in a suitable location, there is a risk that Producer Y could become a stranded asset. In addition, by allowing and subsidising blending in this case study, this may incentivise projects to take greater risks and oversize, rather than 'right-size' for future demand, although this can, in part, be mitigated by the allocation round's eligibility and competitive nature.

Non-quantified benefits

Bringing forward production and demand

In addition to optimising production for projects which have secured offtakers for 100% of their supply at the outset of their project (described in the first case study), if we support blending as an offtaker in locations where electrolytic projects can mitigate network constraints (described in the second case study), blending may bring forward additional production capacity. Supporting additional production capacity could increase total production costs, and total support costs, if, for example, blending results in greater production capacity receiving support. Although production and support costs may increase, there are longer term benefits, described in this section, that may result from growing the hydrogen economy more quickly. In addition, by bringing forward additional production capacity, blending could increase the certainty of supply, which could in turn bring forward hydrogen demand.

Wider hydrogen economy benefits

There are some benefits to the wider hydrogen economy which could result from bringing forward production. By bringing forward some production (e.g. electrolytic projects in certain locations in the UK), blending could support the government's ambition to have up to 10GW production capacity. Further, as described in the Chapter 3, blending could bridge the gap while there is volume risk because production projects are reliant on transport and storage infrastructure. If enabling hydrogen blending brings forward additional production capacity, this could stimulate hydrogen technology supply chains, improving supplier capability and reducing costs over the longer term. Additionally, making a positive strategic decision on hydrogen blending has the potential to improve the global image of UK hydrogen development and increase the opportunity for private investment. However, this may be outweighed by some negative views on the use of hydrogen for blending.

Consumer acceptance

Consumer research conducted alongside the hydrogen blending trials at Keele University and Winlaton found that there was limited understanding and high levels of unfamiliarity of the public in relation to hydrogen and its potential role in the energy study.[32] During the study however, there was strong support for the use of blended hydrogen in the home, in response largely to the perceived environmental benefits. The study concluded that "experiencing

[31] Transmission network constraints occur when the electricity transmission system is unable to transmit power to demand locations due to congestion on the network – i.e. the maximum capacity of the circuit is breached. When constraints occur, National Grid Electricity System Operator (ESO) manage this by paying generators to switch-off (turn-down) in locations where the network is congested and paying generators to switch-on (turn-up) in locations closer to demand.
[32] https://hydeploy.co.uk/app/uploads/2018/02/customer-perceptions-report.pdf (Accessed in August 2023)

hydrogen in the home through a 20% blend could help pave the way to greater acceptance of 100% hydrogen”.[33]

Curtailment

Curtailment is a purposeful reduction in electricity output and occurs for two main reasons. Firstly, because of oversupply, where there is not enough demand for the electricity produced due to e.g. high wind speeds and secondly, because of transmission constraints, where there isn’t enough transmission infrastructure to transport the electricity to useful demand. As described in the second case study above, theoretically, a potential monetised benefit of hydrogen blending could be a reduction in curtailment payments if hydrogen was produced from electricity that would otherwise be curtailed. Hydrogen produced for blending may be more suitable to alleviate network constraints than hydrogen produced for other offtakers, as blending is a flexible offtaker. This potential monetised benefit has not been included in the quantitative analysis presented in the economic analysis section because this benefit would be dependent on more detailed policy design. Further, we do not have robust projections of when blending may ramp up and down, and therefore how these timings may align with high levels of curtailment. The decision not to include this as a monetised benefit does not negate the Department for Energy Security and Net Zero’s position on the value of hydrogen in decarbonising the power sector.

Non-quantified costs and risks

There are some non-monetised costs and risks which could result from a positive decision on blending. These should be considered, and potentially mitigated, in any commercial support and allocation policy design.

Stranded assets

If producers intend to blend and are not located close to the existing gas network and/or a suitable blending injection point, they may require new 100% hydrogen transport infrastructure to transport their hydrogen to a suitable injection point on the gas network to enable blending. As blending can only be time-limited, given our transition away from natural gas, there is a risk that new 100% hydrogen transport infrastructure developed for blending, especially physical pipelines as opposed to vehicular hydrogen transport, may become obsolete and the assets may become stranded. This could also occur if those producers switch from blending to alternative offtakers where this infrastructure could not be repurposed. On the other hand, transportation infrastructure for blending may be able to assist a potential future transition to 100% hydrogen for heat and/or other end users. Whether a pipeline will be a stranded asset will likely depend on how far ‘upstream’ on the network the injection point is. For example, it is more likely that pipelines further ‘upstream’ on the distribution network may be needed in lower hydrogen demand scenarios whereas the conversion of the full distribution network will only be needed in a scenario where there is widespread use of hydrogen in heat.

Slowing demand deployment for favourable offtakers

A potential risk of supporting blending is that it could disincentivise sales of hydrogen to alternative offtakers and slow the development of other end use markets. In addition, it may be hard to design an effective transition from blending once demand from alternative offtakers

[33] Note that the level of consumer engagement in blending trials is likely to be higher than any potential engagement with blending outside of a trial area.

ramps up. Effective policy design to incentivise offtakers other than blending should mitigate this risk.

Slowing roll-out of heat decarbonisation options

Another potential risk of supporting blending is that this could delay the roll-out of alternative heat decarbonisation options, for example heat pumps. We are clear that blending is not a substitute for actions that deliver full decarbonisation of heating such as accelerating deployment of heat pumps and low carbon heat networks and considering the potential role of 100% hydrogen for heat in the longer-term. It will be important that there is consistent messaging that the objective of blending would be to support wider hydrogen economy growth, rather than to decarbonise heat.

Incentivising inefficient location of production sites

By enabling blending, we could inadvertently incentivise the location of production close to sites most suitable for blending injection, rather than sites with availability of long term offtakers. Whether injection sites will be in different locations to longer term offtakers depends on the take up of hydrogen, which is very uncertain. Like the above non-monetised costs, this risk could be managed through the design of potential support and due diligence to assess projects future offtakers.

Sensitivity analysis

The figures presented in Table 3 of the economic analysis section are estimates of the potential costs of hydrogen production, transport, storage and blending infrastructure costs, which are based on several assumptions. This section explores the impact of changing these cost estimates.

If injection costs are higher than estimated, and production costs remain the same, then injection point costs would be a higher proportion of production costs. Likewise, if injection point costs are lower than estimated, injection point costs would make up a lower proportion of total production costs. In the below table the high injection point cost scenario represents all hydrogen produced for blending being injected into LDZ or Greenfield sites and the low injection point cost scenario represents all hydrogen produced for blending being injected into the NTS offtake site. The range of injection point costs as a proportion of production costs is between 0.1-11.1%. Because it is cheaper to inject hydrogen into NTS offtake sites, it is more likely that a higher proportion of hydrogen produced for blending will be injected into these sites. Injection point costs may therefore be closer to the low injection point costs scenario below in the below table, although this depends on the location of production plants.

Table 4: Sensitivity analysis – blending infrastructure point costs as a proportion of production, transport, and storage costs in a high and low cost scenario (£m, 2021 prices, rounded to the nearest £10m)

	Production, transport, and storage costs	Blending infrastructure costs	Infrastructure costs as % of production, transport and storage costs
High production volume scenario	£29,120	£840	2.9%
High blending infrastructure costs	£29,120	£3,240	11.1%
Low blending infrastructure costs	£29,120	£30	0.1%
Lower production volume scenario	£8,290	£200	2.4%
High blending infrastructure costs	£8,290	£900	10.9%
Low blending infrastructure costs	£8,290	£20	0.2%

If production, transport, and storage costs are higher than estimated, and blending infrastructure costs remain the same, then blending infrastructure costs would be a lower proportion of production, transport, and storage costs. Likewise, if production, transport, and storage costs are lower than estimated, blending infrastructure costs would make up a higher proportion of total production, transport, and storage costs. The below table compares the proportion of blending infrastructure costs if production, transport, and storage costs are 25% higher or 25% lower than the high and lower volumes scenario. In this sensitivity analysis, the range of blending infrastructure point costs as a proportion of production, transport, and storage costs is between 1.9-3.8%.

Table 5: Sensitivity analysis – blending infrastructure point costs as a proportion of production, transport and storage costs where production costs are either 25% higher or lower (£m, 2021 prices, rounded to the nearest £10m)

	Production, transport, and storage costs	Blending infrastructure costs	Infrastructure costs as % of production, transport and storage costs
High production volume scenario	£29,120	£840	2.9%
25% higher production and T&S costs	£36,400	£840	2.3%
25% lower production and T&S costs	£21,840	£840	3.8%
Lower production volume scenario	£8,290	£200	2.4%

25% higher production and T&S costs	£10,363	£200	1.9%
25% lower production and T&S costs	£6,218	£200	3.2%

The costs affecting this analysis are very uncertain and will also change on a project-by-project basis. If costs associated with blending outweigh the potential benefits, it may not be beneficial for projects to blend. This may be apparent on a project-by-project basis and could also be true at a system level. As estimates of the costs of production, transport, storage, and blending infrastructure improve, these estimates can be updated. Based on the figures presented in the economic analysis section, and in this sensitivity analysis, we still assess that blending has the potential to contribute to a reduction in production costs that is greater than blending infrastructure costs.

Method and assumptions

Production, transport, and storage costs

- These costs are an estimate of the total cost of producing, transporting, and storing the volumes of hydrogen presented in Table 3 of the economic analysis section, and in the sensitivity analysis section above.
- To come up with these estimates we needed to make several assumptions, including for example, the proportion of production from different technologies, and the types of transport and storage infrastructure used.
- The production costs are based on costs published in the Hydrogen Production Costs report which have been updated to reflect revisions to the Green Book energy price series published last year.[34] These figures include the costs of CCUS transport and storage for blue hydrogen.
- Hydrogen transport and storage costs are based on levelised costs and proportions presented in the Hydrogen Infrastructure Requirements up to 2035 report published in 2022.[35]
- As production cost estimates are refined based on project data, and our estimates of transport and storage costs improve, this analysis can be updated.

Blending infrastructure costs

- The blending infrastructure costs are an estimate of the costs of injecting hydrogen into the network, and any upfront costs necessary to enable accurate billing.
- We assume that 50% of the hydrogen produced for blending is produced in a cluster and that hydrogen produced in clusters is injected into the network at NTS offtake sites. This is based on analysis of the locations of the projects interested in blending in the Department’s production pipeline based on market intelligence and 50% of these are in

[34] https://www.gov.uk/government/publications/hydrogen-production-costs-2021
[35] https://www.gov.uk/government/publications/hydrogen-infrastructure-requirements-up-to-2035

industrial clusters. To inform estimates of injection site costs it is assumed that between 2025 and 2045, 50% of the hydrogen produced for blending is produced in a cluster.

- It is not definite that if a production plant is located in a cluster, and it planned to blend hydrogen that it would use an NTS offtake site. However, NTS offtake sites are more common in denser areas, like industrial clusters, so in order to estimate the proportion of hydrogen produced for blending that could be injected into different sites, and the associated costs of these, the analysis presented in Table 3 assumes 50% of the hydrogen produced for blending is produced in a cluster and therefore 50% of hydrogen produced for blending is injected into the network at NTS offtake sites.

- This assumption does not mean that, for example, all hydrogen produced in clusters would need to use this specific injection site. As highlighted in the economic analysis, the exact implementation would be dependent on specific projects. The purpose of this analysis is to illustrate the potential scale of the costs, not to make forecasts on how we predict blending may grow.

- To calculate how many NTS offtake injection sites will likely be needed to receive the hydrogen produced for blending, we first estimated the number of industrial clusters there would likely be per year. Government's aim is to have 2 clusters from 2025 and 4 from 2030.[36] Assuming there is a maximum of 7 industrial clusters in 2045, the number of clusters increases by 2 every 5 years.

- Next, the hydrogen produced for blending in clusters (50% of the total hydrogen produced for blending each year) is divided by the number of clusters that year to estimate the hydrogen produced for blending per cluster.

- The analysis uses the capacity of an average NTS offtake site (provided by the Gas Goes Green project and presented in the economic analysis section) to calculate the whole number of NTS injection sites needed per cluster to receive the amount of hydrogen produced for blending in that cluster. This is then multiplied by the number of clusters to get the number of NTS injection points needed in total. In both the higher and lower scenario, this is a maximum of 7. In the lower scenario, each individual site will receive less hydrogen – equivalent to operating at a lower load factor.

- The remaining 50% of hydrogen produced for blending is assumed to be injected into LDZ and Greenfield sites and that this is split equally between the two types of sites – 25% of the total for each. This 25% is an arbitrary assumption. To calculate how many LDZ and Greenfield injection sites are needed, this analysis uses a similar method as for NTS offtake sites but does not need to consider the number of clusters.

- Based on evidence to date, for blending to be implemented there is some infrastructure necessary to allow accurate billing. In this analysis, the costs associated with Option A (described in detail in Chapter 7) are considered.

- Most of these costs are included in the injection site infrastructure costs, described above. In addition to the injection site costs, there is an upfront, one-off system cost of around £300,000 necessary to blend hydrogen within existing frameworks.[37] This one-off upfront cost has been included in the blending infrastructure costs presented in

[36] https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest/october-2021-update-track-1-clusters-confirmed
[37] This figure is based on evidence provided by the gas networks.

Table 3 of the economic analysis, and the sensitivity analysis presented at the start of this annex.

- As described in Chapter 7 there is evidence that Option C (described in detail in Chapter 7) may provide benefits as gas in the network becomes more heterogenous and could enable more flexible blends of hydrogen up to 20% by volume. The costs associated with Option C have not been included in the figures presented in the economic analysis section as Option C is not necessary to enable blending, and the decision on whether to undertake a feasibility study into this option will be taken separately to a policy decision on hydrogen blending. Please refer to the Chapter 7 for more details.

Air quality impacts

This economic analysis assessment makes a pragmatic assumption that all hydrogen produced for consumption (whether for blending or other uses), displaces natural gas and the monetised benefits associated with this are the greenhouse gas emission savings, and air quality benefits, per the Green Book guidance. There is some evidence that hydrogen production and use may have detrimental impacts on air quality, for example due to changes in NOx emissions. For NOx emissions, a literature review by the National Centre for Atmospheric Science in 2022 concluded that reports are highly variable and "for a 5% hydrogen blend, changes in NOx emissions, when compared to burning pure natural gas, vary over the range –12% to +39%, with a mean change across 14 studies of +8%".[38] In the future, as the evidence base on air quality improves, these potential impacts could be included in the monetised costs of blending.

[38] https://online.ucpress.edu/elementa/article/10/1/00114/183173/Emissions-of-NOx-from-blending-of-hydrogen-and (Accessed in September 2023)

www.gov.uk/government/consultations/hydrogen-blending-into-gb-gas-distribution-networks

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