Department for
Energy Security
& Net Zero

Hydrogen Blending into the GB Gas Transmission Network

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

Closing date: 16 September 2025

July 2025

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.

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 2023 the previous government consulted on the potential strategic and economic value of the blending of up to 20% hydrogen by volume into existing GB gas distribution networks and options for its implementation. We are now seeking stakeholder views to help inform our assessment of the potential strategic and economic value of blending into the GB gas transmission network (National Transmission System [NTS]) and lead options for its implementation, if enabled.

Consultation details

Issued: 23 July 2025

Respond by: 16 September 2025

Enquiries to: hydrogentransportandstorage@energysecurity.gov.uk

Hydrogen Economy Team
Department for Energy Security and Net Zero

6th Floor, 3-8 Whitehall Place
London
SW1A 2AW

Consultation reference: Consultation on Hydrogen Blending into the GB Gas Transmission Network

Audiences: This consultation will be of interest to stakeholders involved in the hydrogen economy and natural gas networks, including, but is not limited to:

- 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 the existing GB gas transmission network, however responses are invited from all parts of the UK. The Department for Energy Security and Net Zero (DESNZ) 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. Outline whether responses should be provided in a particular preferred format, where electronic responses should be emailed to, which address to send hardcopy responses to, whether to use different addresses for responses for the devolved administrations, etc.

Respond online at: https://energygovuk.citizenspace.com/energy-security/hydrogen-transmission-level-blending/

Write to:

Hydrogen Economy Team
Department for Energy Security and Net Zero
6th Floor
3-8 Whitehall Place
London, SW1A 2AW

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

This consultation

This consultation seeks to understand the potential strategic and economic value of blending into the GB gas transmission network. It sets out our assessment of the aspects of commercial, market, technical and billing arrangements that would be needed to accommodate hydrogen blending into transmission networks, should blending be supported and enabled by government. It also considers the implications for existing end users directly connected to the transmission network and developments across Europe in relation to the EU Hydrogen and Decarbonised Gas Market Package. We are seeking stakeholder views on this current assessment of blending, including our minded to position to consider further whether to support and enable transmission blending of up to 2% hydrogen by volume. The assessment in this consultation has been informed using the evidence that has been gathered to date. Government will carefully assess all available evidence to ensure that the potential impacts and costs are weighed against benefits to inform future decisions.

Your feedback will enable us to develop informed policy.

Chapter 2 Role of this consultation: Sets out the role of this consultation in informing policy decision-making around transmission blending. This chapter provides an update on the blending safety assessment and sets out considerations for potential regulatory changes.

Chapter 3 Strategic considerations of hydrogen blending: Sets out the potential strategic role of blending as an offtaker of last resort for all currently eligible hydrogen production technologies and a potential strategic enabler for certain electrolytic hydrogen producers to support the wider energy system, which has been consulted on by the previous government as part of the 2023 consultation on distribution blending[1]. It also considers interactions with the EU regarding the EU Hydrogen and Decarbonised Gas Market Package.

Chapter 4 Impact of blending on end users connected to the GB National Transmission Network (NTS): Considers the potential safety, operability, performance and efficiency impacts and risks on NTS end users of accepting a variable hydrogen blend and whether any modifications to equipment and processes or mitigations would be required and any associated costs of these.

Chapter 5 Implementation options: Sets out aspects of the commercial, market and technical arrangements that could accommodate transmission blending should it be supported and enabled by government.

[1] DESNZ (2023) 'Hydrogen Blending into Gas Distribution Networks – A consultation to further assess the case for hydrogen blending and lead options for its implementation, if enabled.'

Chapter 6 Conclusion: Sets out our minded to position based on current evidence that we will consider further whether to support and enable transmission blending of up to 2% hydrogen by volume.

Economic analysis: Sets out the economic analysis, based on evidence to date, and invites feedback on the economic analysis presented.

The hydrogen economy and hydrogen blending

Low carbon hydrogen is essential to achieve the Government's Clean Energy Superpower and Growth Missions. It will be a crucial enabler of a low carbon and renewables-based energy system and will help to deliver new clean energy industries which can support good jobs in our industrial heartlands and coastal communities. Hydrogen presents significant growth and economic opportunities across the UK by enhancing our energy security, providing flexible, cleaner energy for our power system and helping to decarbonise vital UK industries.

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 facilitate an optimised hydrogen economy both in terms of location of electrolytic production and minimising system costs for consumers.

In 2023, following consultation, previous government published a strategic policy decision[2] which set out that it saw potential strategic and economic value in supporting the blending of up to 20% hydrogen by volume into the GB gas distribution networks in certain circumstances that align with the strategic role of blending.

We are building the evidence base to determine if blending into the transmission network meets the required safety standards, is technically feasible, economic, and supports government's broader strategic and net zero ambitions. This consultation will help inform the case for and volume of transmission-level blending.

[2] DESNZ (2023) 'Hydrogen Blending into GB Gas Distribution Networks: A strategic policy decision'

Chapter 2: Role of this consultation

The responses to this consultation will help to inform the strategic and economic case for transmission-level blending. National Gas Transmission (NGT) have been undertaking trials, demonstrations and tests to gather evidence to demonstrate whether and/or how different levels of blending of up to 5%, 10% and 20% hydrogen by volume can be used safely within the GB gas transmission network. DESNZ will work closely with the Health and Safety Executive (HSE) to ensure any relevant evidence is assessed independently and robustly before any steps to implement transmission blending are made.

We will take a policy decision on whether to support and enable transmission blending following completion of the safety assessment and finalisation of the economic assessment. That decision will consider any implications from the safety assessment and any further evidence gathered on blending's feasibility and economic case, including via responses to this consultation. 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. As such a positive safety case does not mean government would make a positive policy decision to support and enable transmission blending. To enable transmission blending will also require a positive safety case and positive policy decision on distribution blending as - once hydrogen is injected into the gas transmission network - it could flow downstream into the lower pressure gas distribution networks (GDNs).

If the outcomes from this consultation, safety review, finalisation of the economic case and distribution blending policy decision support a future decision to enable blending into the GB gas transmission network, government would then look to start the legislative process to implement amendments, working with industry and networks to define and deliver the technical implementation activities and processes required. Given likely timescales for this, we do not anticipate blending at a commercial scale to commence before 2028 at the earliest.

Chapter 3: Strategic considerations of hydrogen blending

In December 2023 a strategic policy decision[2] was published by the previous government which set out that it saw potential strategic and economic value in supporting the blending of up to 20% hydrogen by volume into the GB gas distribution networks in certain circumstances that align with the strategic role of blending, as set out in the government response[3] to that consultation and below for convenience.

Strategic role of hydrogen blending

As an offtaker of last resort (or minority offtaker) blending could 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") thereby impacting the production project's revenue, or an offtaker is delayed in being able to purchase the hydrogen when the producer becomes operational. We envisage that this would apply to all types of low carbon hydrogen production projects. Blending may also help to mitigate cross-chain volume risks relating to development of hydrogen transport and storage (T&S) infrastructure, for example if an infrastructure project is delayed. Having the option to blend could help to reduce investment risk into hydrogen production and in certain circumstances may have the potential to lower production costs.

In addition to this, and in the initial absence of larger-scale hydrogen T&S infrastructure, blending may also have value as a strategic enabler to enable electrolytic hydrogen producers to locate to support the wider electricity 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 envisage that in certain circumstances these projects may be considered to receive the revenue support through the Hydrogen Production Business Model (HPBM) on the basis of them being able to use blending as a majority offtaker from the outset on the basis they will transition to other hydrogen offtakers as hydrogen T&S infrastructure materialises. Further details would be set out in an allocation round's guidance and eligibility criteria, if blending is enabled and supported.

By contrast, Carbon Capture Usage and Storage (CCUS)-enabled and other non-electrolytic hydrogen projects would be unable to support the wider electricity system in this way. The strategic value of these projects is to produce hydrogen at scale in centres of high demand, such as industrial clusters, thus allowing these projects to blend as a majority offtaker risks diverting low carbon hydrogen away from local end users with greater decarbonisation potential. Therefore, government does not envisage awarding the hydrogen production revenue support contract - the Low Carbon Hydrogen Agreement (LCHA) - to support CCUS-

[3] DESNZ (2023) 'Hydrogen blending into GB gas distribution networks: government response'

enabled and other non-electrolytic hydrogen projects to use blending as a majority offtaker from the outset.

Blending could therefore play a role to facilitate an optimised hydrogen economy both in terms of location of electrolytic production and minimising system costs for consumers.

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 we expect to reduce as we progress towards net zero. For this reason, it may only have a limited and temporary role in gas decarbonisation as we reduce the use of natural gas. As set out in the UK Hydrogen Strategy[4], the use of hydrogen would be most valuable where there are limited alternative routes to decarbonisation, such as for industries for which direct electrification is not an option.

It is also important that we avoid distorting the offtaker market and reduce the risk of blending ’crowding out’ other offtakers of hydrogen who require it to decarbonise by targeting blending in circumstances where it has potential to reduce overall costs.

The primary strategic role of blending is not to decarbonise the existing gas network or to facilitate a transition to heat decarbonisation. Whilst there would be some carbon savings as low carbon hydrogen displaces natural gas, the main objective of blending would be to support hydrogen production in a targeted way where it has potential to reduce risk and cost at a project or system level.

Transmission-level blending

The NTS is the high-pressure gas pipeline network used to transport gas throughout England, Scotland and Wales. It transports gas at pressures of up to around 94 bar (approximately 94 times the normal atmospheric pressure). 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 has direct interconnections with Belgium and the Netherlands to trade gas and receives pipeline gas exported directly from Norway's offshore fields[5]. It also delivers gas via interconnector pipelines to Northern Ireland and the Republic of Ireland. The NTS connects to gas storage facilities and 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. NGT are the owner and System Operator (SO) of the NTS.

Gas is transferred from the NTS to lower pressure Gas Distribution Networks (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

[4] DESNZ (2021) ‘UK Hydrogen Strategy’

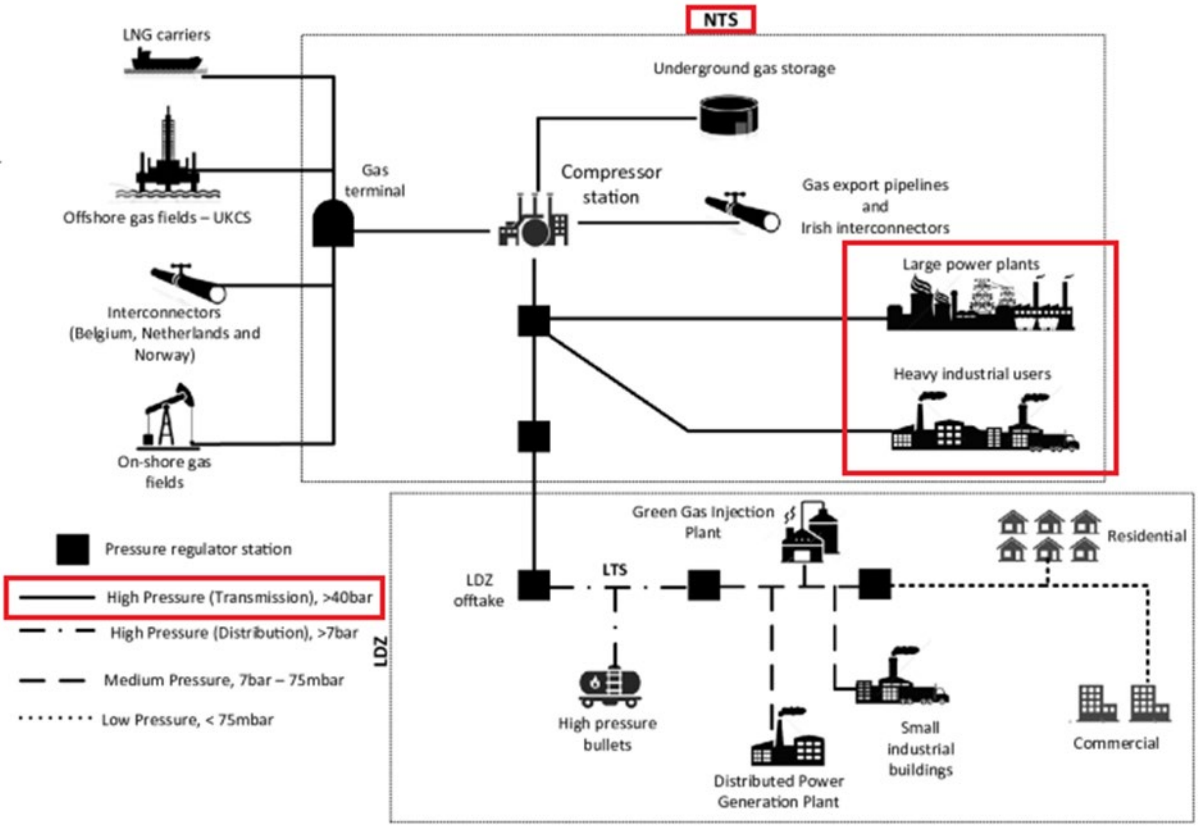
[5] Norway’s upstream pipelines export gas directly from Norway’s gas fields only and are therefore not relevant to this consultation as they are not defined as gas interconnectors.

progressively reduce the pressure of the gas in stages. Each GDN is comprised of four tiers of pipeline pressure, as outlined below:

- 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.

Figure 1: Diagram showing interactions between the NTS and GDNs[6]



A diagram showing the full end-to-end structure of the GB gas system, highlighting in red where end-users of the gas transmission network (e.g. large power plants and heavy industrial users) sit within it.

A strategic role for blending at transmission level could include the potential roles already identified at distribution level (i.e. as an offtaker of last resort and strategic enabler).

[5] DESNZ (2025) 'Arup: National Transmission System Hydrogen Blending Study'

The implications of transmission-level hydrogen blending on cross-border trade with the EU via interconnectors is detailed below; Chapter 4 details the potential impacts of transmission-level blending on existing gas end-users connected to the transmission network.

EU interactions

The UK remains a net importer of natural gas to meet its overall demand. The primary sources of imported natural gas for the UK are pipelines from Norway - which constitute the majority of imports - and shipments of liquefied natural gas (LNG), which are playing an increasingly important role. GB also trades natural gas via its interconnectors with Northern Ireland (NI), the Republic of Ireland (ROI)[7], Belgium, and the Netherlands.

EU Gas Package and cross-border trade

The EU Hydrogen and Decarbonised Gas Market Package (consisting of Directive (EU) 2024/1788 and Regulation (EU) 2024/1789) was adopted in May 2024 and the Regulation was applied on 5 February 2025. Member States have until 5 August 2026 to transpose the rules of the Directive into national law.

The Package provides a framework to enable harmonisation of hydrogen blending across Member States to support up to 2% hydrogen blends across EU gas transmission networks. It provides no explicit requirement for individual Member States to blend hydrogen into their transmission systems, noting that EU Member States' right to take the decision on whether to apply blending of hydrogen into their national natural gas systems should be preserved.

Equally, Member States are free to blend hydrogen > 2% by volume into their domestic gas system. They are also free to trade those volumes with neighbouring Member States, but this may be contingent on individual bilateral agreements and there are no provisions within the EU Gas Package to facilitate this.

The current limit for hydrogen within the natural gas network in GB is 0.1% by volume, as set out under the Gas Safety (Management) Regulations 1996 (GS(M)R). If gas blended with hydrogen >0.1% reaches an interconnector it could not currently be accepted by GB. In this scenario the interconnector would temporarily cease activity until such time as the available gas was demonstrably consistent with the quality requirements of the GS(M)R.

We have therefore engaged with policy officials and transmission system operators (TSOs) of neighbouring administrations to understand the implications of the EU Package regarding hydrogen blending and any potential risks to security of supply[8].

[7] Interconnectors between GB and both NI and ROI are unidirectional and only export gas from GB.
[8] Norway's upstream pipelines export gas from Norway only and are therefore not relevant to this consultation as they are not defined as gas interconnectors.

Northern Ireland

NI imports the majority of its gas from GB via the Scotland-Northern Ireland Pipeline (SNIP), a unidirectional interconnector. It is also connected to the ROI via the South-North pipeline which has been utilised when capacity on the SNIP was insufficient. NI has not yet reached a decision on hydrogen blending in their transmission system, but we will continue to engage with policy officials as the policy develops.

Ireland

Ireland is in a similar position to NI, in that it imports the majority of its gas from GB via unidirectional interconnectors. Ireland has not yet reached a final decision on hydrogen blending in their transmission system but have indicated that they would work constructively with GB to be able to accept flows of blended hydrogen if required. Given the lack of export flows from the island of Ireland to GB we do not consider there to be a risk of blended volumes reaching GB in the foreseeable future.

Belgium

In July 2023, Belgium amended its regulations to enable up to 2% hydrogen within local networks without connection to interconnection points or the underground storage facility managed by its TSO, Fluxys. By limiting blended volumes to such local networks they can be isolated from any shared interconnectors. This can be achieved by system planning and management, wherein Fluxys would not permit hydrogen to be blended into the network where it would risk flowing to interconnection points, and any blending flows would be interruptible to ensure volumes could be effectively managed.

However, in a potential future scenario where Belgium accepted blended flows from a neighbouring country (including the UK) they would not be able to effectively prevent those volumes from reaching other interconnection points. Belgium would therefore consult the TSOs of all neighbouring countries before deciding whether to accept those blended volumes. Belgium and the UK are also obligated to cooperate to ensure uninterrupted flows of natural gas by the treaty underpinning the GB-BE interconnector. This is therefore a key consideration by both states when considering hydrogen blending policy.

Netherlands

The Netherlands currently does not allow hydrogen blending in its gas transmission system. If the Netherlands were to decide to allow hydrogen blending, this would require legislative changes. The timelines associated with reaching a decision, making the required legislative changes, and the eventual construction of associated infrastructure (e.g. injection points) mean that any risks to cross-border flows due to regulatory misalignment in the near to medium term are minimal.

In the longer term, as is the case with Belgium, the treaty underpinning the GB-NL interconnector obligates both the UK and the Netherlands to cooperate to ensure uninterrupted flows of natural gas. This would therefore be a key consideration by the Netherlands when assessing whether to enable hydrogen blends in its transmission system, and vice versa.

Summary

Given the positions of neighbouring states, we consider that the risk of any gas blended with hydrogen reaching an interconnector in the short/medium term (i.e. next 3-5 years) is minimal.

We recognise that in the longer term this situation may evolve, and we will therefore continue to engage with neighbouring states as the policy landscape and hydrogen economy across Europe develops.

Chapter 4: Impact of blending on end users connected to the GB National Transmission Network (NTS)

As set out in Chapter 3, the NTS is the high-pressure gas pipeline network used to transport gas throughout England, Scotland and Wales.

Hydrogen has different physical properties and characteristics to natural gas and as such may have implications for end users connected to the network. These users often operate equipment that is sensitive to the quality of the gas supplied. As such, hydrogen being blended into this gas could impact their ability to operate or require them to invest in de-blending equipment (where hydrogen is removed from the gas supply prior to use).

As discussed in Chapter 2, government is working with HSE to review evidence to assess the safety of blending into the existing transmission network.

DESNZ consultation on distribution blending

In the 2023 consultation on distribution blending[1] previous government asked whether stakeholders had any views or concerns with blending into the GB gas transmission network. As set out in our government response to this consultation[2] there was approximately an even split between those who were generally positive about the prospect of transmission-level blending, and those who either had concerns or withheld judgement pending further evidence and consideration. Of those respondents who had concerns some specifically noted that challenges which could be faced by industrial and power generation sites connected to the transmission networks may be more significant compared to users connected at distribution-level, particularly those reliant on natural gas as a feedstock. Some respondents noted that consideration of the possible need for mitigations such as deblending (a process to separate the hydrogen from natural gas) with assessment of associated costs, would be crucial to any government decision on transmission-level blending.

If hydrogen blending into the NTS is enabled by government, it is considerably likely that blend levels across the network would vary. This is likely to be driven by hydrogen producers' requirements to blend a variable profile of hydrogen, seasonal variations in gas demand, and the import and export of any blended gas across interconnectors to/from the UK and EU. It would therefore be difficult to ensure a fixed hydrogen blend percentage is delivered to offtakers.

Before any policy decision on whether or not to support and enable blending into the NTS can be made it is necessary to consider any further potential operability and commercial impacts to network end users of accepting a variable hydrogen blend and the extent to which any mitigations (such as deblending) or modifications to equipment and processes might be required.

National Gas Transmission: Progressive Energy study

NGT commissioned Progressive Energy to assess the potential safety and technical issues relating to the adoption of 100% hydrogen and a variable blend of hydrogen (up to 20% by volume) in natural gas for those sites which are directly served by the NTS. These include power generators, gas compression and storage sites and a range of industrial processes.

This acceptability study[9] included three phases. Phases one and two of this study identified the following selection of technology archetypes that can be widely applied to the NTS directly connected end users: Gas Turbine, Gas-fired Reciprocating Engine (‘Reciprocating Engine’), Indirect Firing, Direct Firing, Chemical Feedstock, Storage, Compression, Expansion and Gas Conditioning. Phase three of this study was focused on identifying the generic impacts of fuel switching from natural gas to a 20% hydrogen blend and 100% hydrogen for each of the technology archetypes.

A gas characteristics review was first conducted to highlight how the gases would behave differently in an industrial setting and identify potential implications for site design and operation. Building on this work, a desktop-based impact assessment was then conducted to investigate the safety, technological and regulatory impacts that could arise during the fuel switching process.

A selection of end users who are directly connected to the NTS were engaged and studied to apply the findings of the impact assessment against real-life applications, and to help understand the extent of changes required for sites to enable a switch to a 20% hydrogen blend. The sites were selected, amongst other reasons, to ensure complete coverage of each of the technology archetypes.

The main conclusion from the acceptability study is that most applications are capable of handling up to a 20% hydrogen blend today, albeit with some level of modification expected (e.g. burner replacement/ compressor upgrades). The level of modifications required increases with the blend percentage, with up to 2% and 5% requiring fewer modifications than 20%.

The study also highlighted that for network end users that use gas as a chemical feedstock for methane reforming process to produce hydrogen, the addition of 20% hydrogen by volume into the feedstock can negatively impact on the volume of hydrogen and carbon monoxide produced as an output.

Compressors are likely to require some of the most extensive modifications for 20% blends, however for up to 5% blends the thermodynamic properties do not change significantly from natural gas.

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[9] National Gas (2025) ‘Hydrogen Acceptability Summary Report.pdf’

If hydrogen blending were to be enabled in the NTS the maximum percentage of hydrogen that could be present in any gas received would be known to end users. However, blend variability is a concern for most end users. NGT are currently exploring routes to mitigate this impact.

The study highlighted that, as most processes are optimised for natural gas composition (the quality of which is tightly regulated), adaptations may be required to manage blend variability. It recommended that sites should conduct a site-specific assessment in collaboration with Original Equipment Manufacturers (OEMs) and site engineers to better understand in detail the potential safety, technical, environmental, and economic impacts of transitioning to a hydrogen blend. It also noted that further work is required to fully assess any potential barriers and develop a complete transition pathway.

Arup survey

The Progressive Energy study did not consider specifically the impacts of lower levels of hydrogen blend (up to 2% and up to 5%) or the cost and time implications of modifications and/or mitigations that could be required. The DESNZ commissioned Arup to conduct a technical survey of OEMs and end users connected to the NTS to assess:

- The extent of any safety, operability, performance and efficiency impacts and risks of accepting a variable blend of up to 2%, up to 5% and up to 20% hydrogen by volume;
- Whether any modifications to equipment or processes or mitigations (such as deblending) would be required and any associated costs of these;
- The timeline for NTS end users to be operationally ready to accept variable blends;
- Technologies offered, any technical and operational challenges, research and development for hydrogen ready equipment and the support OEMs could provide to their customers in a transition to accepting a hydrogen blend.

A workshop was also held with key stakeholders, facilitated by the trade association Energy UK, including offtakers and other interested industry parties, to enable an open discussion on the survey questions.

Of the 54 sites connected to the NTS, responses were received from 11 NTS connected users representing 30 sites. Of these, 24 sites were power generation, three were industrial users and three were storage sites. Survey responses were given a rating of 1 to 5 based on the site's ability to accept a hydrogen blend at the blend percentages of up to 2%, 5% and 20% (where 1 represents blending being possible at the site without modifications, and 5 represents blending being unable to be achieved at the site under any circumstances).

In addition to the survey and analysis of the responses, Arup also undertook a literature review to better understand the types of end users connected to the NTS. The findings are set out in their National Transmission System Hydrogen Blending Study[6].

Key findings from the end user survey

Overall, the responses suggest that while hydrogen blending into the NTS, particularly at the lower percentage blends, could be technically feasible, most sites are likely to require some level of modification or upgrades to equipment and processes which become more significant, complex and costly as the level of hydrogen blend increases. Key challenges raised were around potential variability in the level of hydrogen blend received, timeframes to be blend ready and constraints on OEMs to deliver the required modifications at the same time.

However, feedback received on specific costs was limited with most sites requiring a detailed engineering study with further OEM engagement before confirming what equipment needs to be upgraded and associated costs and technical assurance/warranties on whether existing equipment can accept a hydrogen blend. These studies themselves would incur costs.

Up to 2% hydrogen blends

Thirteen out of the 30 sites who responded to the survey suggested that they could likely receive hydrogen blends of up to 2% with minor or no challenges/modifications. All of these sites are power generation facilities. It is important to note that these sites still suggested that they would require a consultation with OEMs to understand contractual issues associated with receiving hydrogen blends and provide technical assurance.

However, even at a 2% blend many respondents raised concerns that there may be an impact to their operations resulting from variability in the percentage of hydrogen they would receive in their supply, where the percentage of hydrogen volume received may fluctuate between 0% and the maximum blend percentage (2%, 5%, or 20%). Reduced gas turbine performance and efficiency was highlighted by seven sites as the lower calorific value (energy content) of hydrogen would have an impact on the size of equipment required to generate power, which would make the facility less space efficient with a likely reduction in power output.

Safety concerns were raised by nine sites, with the key risk being hydrogen embrittlement. Due to its smaller molecule size compared to natural gas, equipment materials may be susceptible to hydrogen embrittlement and leakage. It is therefore likely that even at the lowest blend percentage, mechanical integrity testing of existing equipment would be required. Several power generation users also raised the requirement for 100% (or very close to 100%) natural gas for safe start up and shut down of gas turbines. This would therefore be complicated by the presence of hydrogen as a pre-blended supply, as opposed to a blend being site controlled.

For the storage sites, the key challenge with accepting a hydrogen blend is a reduction in effective capacity. Natural gas blended with hydrogen has a lower calorific value than natural gas alone, reducing the effective capacity of the gas storage assets in terms of energy content.

The industrial sites who responded indicated they would all require moderate modifications with one site using gas as a feedstock not being able to accept a hydrogen blend of any level and unable to tolerate any costs of deblending.

The survey responses provided very limited estimates for the costs required to be hydrogen blend ready due to lack of OEM technical assurance and uncertainty on what modifications may be required in the absence of detailed studies. One end user estimated that feasibility studies alone could cost ~£1 million and take between 12 to 18 months. Another response estimated that to enable a 2% hydrogen blend the costs for required control system upgrades could be in the region of £10-15 million.

Many respondents highlighted that they do not currently have developed timelines to be hydrogen blend ready. For sites who provided timeline estimates, some anticipate that blending could be achieved as soon as OEM approval and confirmatory studies are provided. Others anticipate that around two years would be required to allow for detailed studies and any equipment upgrades, as well as potential employee equipment and safety training. Respondents representing power generation sites also highlighted that limited OEM capacity and security of supply concerns would preclude the possibility of all sites being retrofitted simultaneously, and so the timeline would need to be further stretched to enable the sites to be modified in sequence.

Up to 5% hydrogen blends

Twenty seven of the 30 sites that responded believe that significant modifications would be required with prolonged downtime and/or significant costs to allow them to accept blends of up to 5%. Reduced turbine operability was a key challenge raised by 22 of the 24 power generation site responses including reduced power output, combustion instabilities and lower efficiency. Fifteen out of 24 power generation sites also mentioned the possibility of increased NOx emissions, which could potentially raise issues with environmental permitting.

The same safety considerations regarding safe startup/shutdown and hydrogen embrittlement and leaks apply to the 5% blending scenario, but with higher risks.

Responses from the storage sites indicated that 5% blending and above would provide substantial technical challenges and likely require significant modification and replacement of surface assets. Greater levels of hydrogen blends would directly impact the storage asset's ability to deliver energy into the gas system. This could have implications in ensuring security of supply, particularly during winter months when demand is highest.

Twenty out of 30 site responses estimate that the long lead times, potentially in the order of three years and longer, would be required to be ready to accept a 5% hydrogen blend. One respondent indicated that OEMs are quoting lead times of up to 24 months for standard components. This therefore becomes an important consideration when considering multiple NTS connected users requiring OEM assessments and/or equipment upgrades simultaneously, if a hydrogen blend is introduced.

Up to 20% hydrogen blends

Twenty nine of the 30 responding sites indicated that significant modifications would be required with prolonged downtime and/or significant costs to allow them to accept blends of up to 20%. All of the 24 power generation facilities who responded to the survey see the variability of the blend being a key technical challenge, with 22 of the 24 facilities highlighting safety issues and a long lead time of procuring the required equipment as barriers in accepting the blended gas. For such significant implications to be foreseen across the board for power generators, this suggests a period of transition to up to 20% hydrogen blending may be long, complicated and at substantial financial cost with potential risk to energy security.

Of the three industrial sites that responded to the survey, two stated that they would not be able to accept up to 20% hydrogen blends, leaving the plant inoperable. Another user stated that the company needs to be protected from the additional costs associated with being supplied with a hydrogen blend to ensure that they can compete internationally.

All of the storage facilities that responded to the survey stated that there would be a long lead time for the required equipment upgrades to accommodate up to 20% hydrogen blends, which would result in a significant outage period that may threaten energy security. As well as the significant costs expected, there would also be a reduction in the storage capacity of the assets, which would reduce the income of each facility and may mean that additional storage assets would be required to give the UK the same storage capacity in terms of energy.

Key findings from OEM survey

The stakeholder engagement survey for OEM’s only returned one formal response from a reciprocating engine manufacturer. This manufacturer stated that for up to 5% hydrogen blends there are no issues for their equipment; with no modifications required or challenges foreseen. They stated that for hydrogen blends up to 20%, a hydrogen blend signal would be required to notify the control system of the blend percentage and allow the ignition to be controlled appropriately. For engines older than five years, the OEM stated that it may be necessary to upgrade the control systems to the latest software, which may require around one working week disruption if replacement of the system is required during a planned outage.

In addition to the survey being completed by the OEM above, two email responses were received from gas turbine manufacturers. One manufacturer suggested that all their current gas turbine models can handle up to 5% hydrogen blends, with higher blends likely to require an upgrade to combustion systems. Regarding any upgrades for existing NTS-connected sites, they advised that the associated costs and schedule are very site specific and would require further investigation to provide specific values of the cost including consideration of auxiliary piping, upgrade of combustors and associated controls, and potentially moving vent stacks. Another respondent also produces gas turbines which are suitable for use with hydrogen blends, however they stated that studies to determine specific power plant conversion requirements would have to be procured at the request of the plant owners.

Hydrogen deblending

Hydrogen deblending is the process of separating out hydrogen from a blended gas stream. It could play a role in helping to manage the needs of certain NTS end users who would be unable to, or face significant safety and technical challenges in, accepting a variable hydrogen blend. However, deblending is a relatively unproven technology on a large scale, such as in a distribution and transmission networks. The International Energy Agency rated deblending as a Technology Readiness Level (TRL) of 4 (early prototype)[10].

As discussed in Chapter 3 the EU Hydrogen and Decarbonised Gas Market Package provides a harmonised approach on blending up to 2% of hydrogen into the natural gas system at cross-border interconnection points between EU Member States. Whilst current evidence suggests that there is minimal risk of gas blended with hydrogen reaching shared interconnectors in the short-medium term, this position could change in the future.

Deblending at UK gas interconnector entry points

There is a potential future scenario where the available evidence supports a future policy decision not to support or enable domestic hydrogen blending into the NTS (for example if it is not deemed safe) but an EU Member State injects hydrogen blends into its transmission network and blended gas reaches its shared UK gas interconnector. There is also a risk of the inverse scenario, where the evidence supports enabling domestic hydrogen blending in GB but neighbouring EU Member States choose not to do so. To ensure continued interoperability and mitigate risks to the cross-border trade of gas with the EU in this scenario, consideration has been given to the feasibility of large scale deblending at interconnection points in the UK.

Initial evidence from NGT suggests that the large scale deblending of hydrogen at a national level could be costly and technically complex. Further work would need to be undertaken to assess the feasibility of developing and operating such large-scale facilities at interconnection points.

Based on current evidence, due to the likely significant costs and technical complexities we do not currently view large scale deblending at a national level as a preferred solution. We will continue to engage with EU Member States and the Commission to explore mitigations in the event of misalignment between UK and EU hydrogen blending policy.

[10] International Energy Agency (2023) 'Global Hydrogen Review 2023'

Deblending at local end user level

An alternative to large scale deblending at interconnectors would be to consider deblending for those NTS end users or applications that cannot accept a hydrogen blend or require significant modifications or changes to their equipment and processes. Engineering studies would be required to assess the suitability of deblending for specific end users who may have different specific requirements for gas quality.

NGT have undertaken several projects, including a Hydrogen Deblending Feasibility Phase 2 project[11] which assessed the feasibility of deblending for a range of applications, gas compositions and volumes and provided some information to enable the costing of deblending solutions. It demonstrated that estimated costs for deblending can vary greatly and increase significantly when attempting to reach very low hydrogen concentrations such as the current regulatory limit of 0.1% contained in the Gas Safety (Management) Regulations (GS(M)R) compared to a 1% hydrogen blend. The Arup study used a range of deblending cost estimates provided by NGT to generate some high-level estimates of deblending costs for a range of archetypes including gas turbines, reciprocating engines and direct and indirect firing processes.

Any decision to implement deblending for an NTS connected user would therefore need to be considered against the cost of equipment modifications or upgrades.

Further work

NGT is undertaking further work to understand:

- Whether it would be possible to isolate blended gas within the NTS to protect sensitive end users; and
- if there are measures that can help manage blend variability to mitigate any impacts on end users.

Question 1.

a) Do you agree with the assessment of the impacts of blending up to 2%, 5% and 20% hydrogen by volume on NTS connected end users? Please provide evidence to support your response.

b) Are there any further operational and/or financial impacts on end users we should consider? Please provide evidence to support your response.

[11] National Gas Transmission (2023) 'Hydrogen Deblending Feasibility Phase 2'

Chapter 5: Implementation options

Our intention is that transmission blending, if enabled, should be implemented in a way that utilises existing gas market arrangements where appropriate to deliver market frameworks that are predictable and enduring. The following sections set out aspects of the commercial, market and technical arrangements that could accommodate transmission blending should it be supported and enabled by government.

Commercial support model

As set out in Chapter 3, in certain circumstances blending has the potential to stimulate an early hydrogen market as an offtaker of last resort through de-risking hydrogen production projects and reducing costs. Blending could also play a role of strategic enabler for certain electrolytic projects in certain locations to support the wider energy system and help manage electricity system grid constraints ahead of the development of regional or national hydrogen T&S infrastructure. However, blending should not ‘crowd out’ other end uses of hydrogen in sectors which are more difficult to decarbonise.

Should transmission blending be supported and enabled by government our aim would be to support it through a mechanism that delivers value for consumers as well as being accessible and effective for hydrogen producers.

In the 2023 consultation on distribution blending[1] previous government assessed options for how commercial support could be provided for hydrogen producers in line with the proposed strategic role of blending. 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 was given to the achievability and deliverability of each option within the required timeframes to realise the strategic benefits. In the government response to the consultation[3] it was confirmed that the most appropriate mechanism, if blending is enabled and commercially supported by government, would be the HPBM.

For these reasons we also consider that, should support be required, the most appropriate mechanism to support transmission blending - if enabled and intended to be commercially supported by government - would be the HPBM.

Further considerations for the HPBM

The same principles would apply when designing any subsidy support for distribution and transmission blending and integrating this within the HPBM, consideration would be given to blending’s strategic role as set out in Chapter 3. In particular, it is important that we 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 LCHA, where blending is currently a non-qualifying offtaker. This includes the interaction with existing design features of the HPBM (e.g. the role of Risk-Taking Intermediaries [RTIs]), technical requirements (e.g. metering and billing) and confirming the level of subsidy support for blended volumes. This work will also consider how any project that has already been awarded a LCHA through earlier allocation processes may be able to request a change to their contract, aligned with our strategic position on blending, to the government-appointed counterparty.

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.

In parallel to the commercial work on the HPBM, we will consider when blending could become an eligible offtaker for future Hydrogen Allocation Rounds (HARs) and CCUS allocation rounds of the HPBM, if it is enabled.

For future HARs and CCUS allocation rounds, we will also consider how to adapt eligibility criteria to be consistent with the two different strategic roles we envisage blending playing, if it is enabled. This means that:

- For CCUS-enabled and other non-electrolytic hydrogen projects, if blending becomes an eligible offtaker, we currently only envisage this for projects where blending is an offtaker of last resort (or minority offtaker). Further details would be confirmed via future CCUS allocation processes, and we might also consider integrating it into an ongoing allocation round, where possible.
- For electrolytic projects, in addition to the offtaker of last resort (or minority) role, we also consider that there may be a case for a project which proposes blending as a majority offtaker (i.e. >50% of volumes) as it could help to optimise the location of electrolysers to help manage grid constraints (i.e. the strategic enabler role) as a precursor to regional or national hydrogen T&S infrastructure in certain locations. This would be confirmed via future HARs and likely considered on a case-by-case basis.

We note that sales of hydrogen to RTIs are not currently an eligible offtaker under the HPBM. Depending on the onward commercial arrangements, this could include gas shippers purchasing hydrogen for the purpose of blending. Further consideration will be given to the commercial design and integration of blending, if blending is enabled by government, within the HPBM.

Question 2.

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

Market and trading arrangements

This section considers the market and trading arrangements for transmission 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.

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 are the primary balancers of supply and demand across the network with NGT, the Transmission System Network Operator, fulfilling the role of residual balancer, demand across the network. NGT also has an obligation under the Uniform Network Code (UNC) to procure NTS shrinkage gas. NTS Shrinkage consists of:

- Own Use Gas (OUG) – the gas required to run the compressor flet and pre-heating of gas;
- Calorific Value Shrinkage (CVS) – the difference between the measured and billed energy entering the Local Distribution Zones as a result of the Flow Weighted Average Calorific Value (FWACV process);
- Unaccounted for Gas (UAG) – the quantity of gas that is lost within the NTS resulting from data and meter errors.

In the 2023 consultation on distribution blending, previous government considered a network-led approach where network operators act as the buyers of low carbon hydrogen produced for blending in lieu of their obligation to purchase shrinkage gas. It also considered a shipper-led approach where shippers act as the buyers for volumes of low carbon hydrogen produced for blending through existing gas market arrangements. Finally, the consultation also considered a third hybrid approach whereby both network operators and shippers could be permitted to act as the buyers for volumes of low carbon hydrogen produced for blending.

Following consultation, previous government concluded that a hybrid approach could be implemented with minimal regulatory change and may offer hydrogen producers the most flexible route to market as a network-led approach alone could potentially limit purchasable volumes of low carbon hydrogen.

We consider this approach could apply to blending into the gas transmission network and are therefore also minded to support a hybrid approach whereby, if blending into the gas transmission network is enabled, the gas transmission system operator and gas shippers can purchase low carbon hydrogen and shippers are able to sell hydrogen produced for blending.

Question 3.

Do you agree with our minded to position, if blending were enabled, to allow both the gas transmission network operator and gas shippers to purchase hydrogen produced for blending? Please provide evidence to support your response.

Low carbon hydrogen certificates for transmission blending

The 2023 Low Carbon Hydrogen Certification Scheme Government Response[12] stated that certificates for low carbon hydrogen should provide a robust and transparent means of verifying the emissions credentials of low carbon hydrogen and outlined the key design features of the certification scheme. Given the complexities of the interactions between blending and certification, we continue to consider further our position (for both distribution and transmission). We aim to explore how certificates could operate in a blending scenario ahead of any final policy decision on whether to support and enable blending.

Technical delivery model

In the 2023 consultation on distribution blending, previous government considered the question of where hydrogen could be injected into GB GDNs and how this should be managed. The government response to that consultation supported the high-level principle of a 'free-market' approach, as described in the Gas Goes Green Programme[13], as the preferred technical delivery model for blending, should blending be enabled by government. This approach would avoid undue discrimination regarding connections and capacity allocation and could also benefit a wider diversity of hydrogen producers of different sizes at different locations.

Through appropriate design of technical models we view that some degree of strategic planning may need to be realised across distribution and transmission networks to help mitigate risks in relation to 'network sterilisation', whereby hydrogen producers wishing to connect in the lower pressure tiers of the network may prevent access to capacity which limits the volumes of hydrogen that can be injected into the high-pressure parts of the network.

We will continue to work closely with gas network operators and wider industry to explore the most appropriate means to deliver blending, considering interactions between distribution and transmission including, but not limited to, connections processes, capacity allocation, trading arrangements and network charging.

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[12] DESNZ (2023) 'Low Carbon Hydrogen Certification Scheme – Consultation Outcome'
[13] Energy Networks Association (2021) 'Gas Goes Green – Delivering the Pathway to Net Zero'

Gas billing arrangements

As discussed in the previous section any hydrogen which is injected into the NTS has the potential to flow downstream into the GDNs.

In the 2023 consultation on distribution blending, previous government concluded that, based on evidence gathered and assessed to date, government intends to work within existing gas billing frameworks should blending be enabled by government. This approach was supported by the Future Billing Methodology Project conducted by industry with funding agreed under Ofgem's Gas Network Innovation Competition, which provided options and recommendations on how the attribution of energy content (Calorific Value (CV)) for billing could be treated in a future with a wide variety of gas sources.[14] The CV of a gas shows the amount of energy that is released when burning a certain volume of that gas.

Although hydrogen blending under existing billing arrangements 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 set out in chapter 3. Significant amounts of hydrogen blending could be achieved under existing billing regulations and this is the lowest cost and quickest to implement option.

NGT bills shippers on an energy basis for the transportation and consumption of gas to and from NTS connected sites. Shippers bill the gas suppliers (they may be the same organisation), who in turn bill the site via separate arrangements. This energy usage is measured in kilowatt hours (kWh) and is determined by both the quantity (or volume) of gas delivered to a gas user and energy content (or CV) 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.

Unlike the majority of users connected the gas distribution network, NTS connected sites have equipment (such as gas chromatographs) that measure the CV of the gas delivered to the end user. This measured CV is used in the billing calculation and multiplied by the volume of gas delivered to determine the energy usage for billing. Any increase in the volume of gas delivered will be offset by the lower CV of that gas and therefore should not result in an increase in the billable energy usage (in kWh) and the cost of bills. Note that this assumes the blended hydrogen is sold at the same price to the end user as natural gas (as could be the case depending on whether/how blending is commercially supported by government and how market participants choose to transact for any hydrogen that is blended).

[14] Cadent Gas Ltd. (2022) 'Future Billing Methodology: Recommendations'

Question 4.

Do you agree that working within the current gas billing arrangements will not result in an increase in billable usage and gas bills for end users connected to the NTS, should transmission level blending be enabled by government?

Please provide evidence to support your response.

Blending interactions with gas meters

NGT have confirmed that all current meter technologies are suitable for up to a 10% hydrogen blend with natural gas. For blends of 20% hydrogen or above, some types of meters will require recalibration. By the end of the RIIO-3 price control period (31 March 2031) NGT intends to replace all turbine meters with more accurate, blend-ready technology and ensure all fiscal metering at network exit points is ultrasonic.

NGT have also confirmed that an upgrade to some gas analysers installed at NTS entry, exit, compressor and process control sites will be required to enable accurate measurement of hydrogen blend content in natural gas (in addition to other components in the gas). NGT is currently undertaking works to prepare this gas analyser fleet in readiness for the possible introduction of hydrogen blends.

Chapter 6: Conclusion

As set out in Chapter 3, we consider that the strategic role blending hydrogen into the existing gas transmission network could play would be analogous to its role at distribution level (i.e. as an offtaker of last resort and strategic enabler) in certain circumstances through mitigating risks and lowering costs for hydrogen projects and the wider energy system.

However, there are further complexities regarding transmission level blending that require consideration alongside any potential strategic benefits. These include interactions with the EU and continued interoperability of the cross-border trading of gas through interconnectors. We will also consider any impacts on end users connected to the NTS of accepting blended gas, such as industrial, power and gas storage sites.

Chapter 4 sets out a summary of the findings from current evidence relating to the impacts of blending on end users connected to the NTS. This evidence suggests that whilst most applications are capable of handling a hydrogen blend of up to 20% hydrogen by volume, the majority of NTS end users will require some degree of modifications or upgrades to equipment and processes, which become more significant, complex and costly as the level of hydrogen blend increases.

Even at the lowest percentage blend (up to 2% hydrogen by volume), the majority of respondents to the Arup survey raised concerns that there may be an impact to their operations resulting from variability in the percentage of hydrogen they receive in their supply, including reduced performance and efficiency, and for storage sites a reduction in capacity.

As set out in Chapter 3, the EU Hydrogen and Decarbonised Gas Market Package provides a harmonised approach on blending up to 2% of hydrogen into the natural gas system at cross-border interconnection points between EU Member States. However, there is no requirement for EU Member States to apply blending in their national gas systems and, as a third country, the EU Gas Package does not apply to the UK or its interconnection points. There is therefore further engagement required with neighbouring Member States to understand their long-term policy aims regarding hydrogen blending and how this might interact with the UK. However, given we do not consider that EU Member States would be likely to accept blends of greater than 2% by volume in the nearest future, there is a strategic rationale to not consider percentages greater than this within the GB gas transmission system.

A 2% hydrogen blend on the NTS equates to an annual injection of approximately 4.7 TWh of hydrogen in 2025, reducing to around 1.9 TWh in 2040 as gas use declines (see Figure 3 in the Economic Analysis section for more detail – note that in practice we would not expect blending to reach the 2% cap for a whole year if it is to remain a flexible offtaker).

Based on current evidence, government is therefore minded to consider further the case for transmission blending for blends up to 2% hydrogen by volume at this time. If blending is introduced, we will consider any potential impacts and whether increasing the 2% limit would be appropriate. Government will carefully assess all available evidence to ensure that the potential impacts and costs are weighed against benefits to inform future decisions.

Question 5.

a) Do you agree with our minded to position, if blending were enabled, to consider further whether to support and enable transmission blending of up to 2% hydrogen by volume? Please provide evidence to support your response.

b) Do you have any further concerns on enabling blending up to 2% hydrogen by volume into the NTS? Please provide evidence to support your response.

c) Is there a maximum level of blend that would be feasible with minimum modifications for sites connected to the NTS? Please provide evidence to support your response.

Economic analysis

The question at hand is whether to enable hydrogen blending into the NTS up to 2% by volume.

As with blending hydrogen into the distribution network, transmission level blending may be able to function as a reserve offtaker for hydrogen producers to manage demand volatility and uncertainty.

Transmission blending, however, may also impose costs on end users of the NTS, and these end users would not directly benefit from transmission blending. Many end users have indicated the need to make system modifications in order to accept blended gas, and in some cases may not be able to accept it at all. They will also have to conduct feasibility studies to determine what modifications may be necessary.

There is considerable uncertainty around the size of these potential costs to end users, due to very limited data. The evidence we do have, however, suggests these costs could be large.

The economics of transmission blending are therefore more complex than for distribution blending, as it would no longer simply be a case of a given hydrogen producer weighing up the costs and benefits for themselves. It would impose costs on third parties (NTS end users) who do not benefit from blending, and it is not clear that any potential system benefits would outweigh these additional costs.

As such, this assessment cannot provide a clear economic rationale for transmission blending and instead recommends further work be done with NGT and industry on:

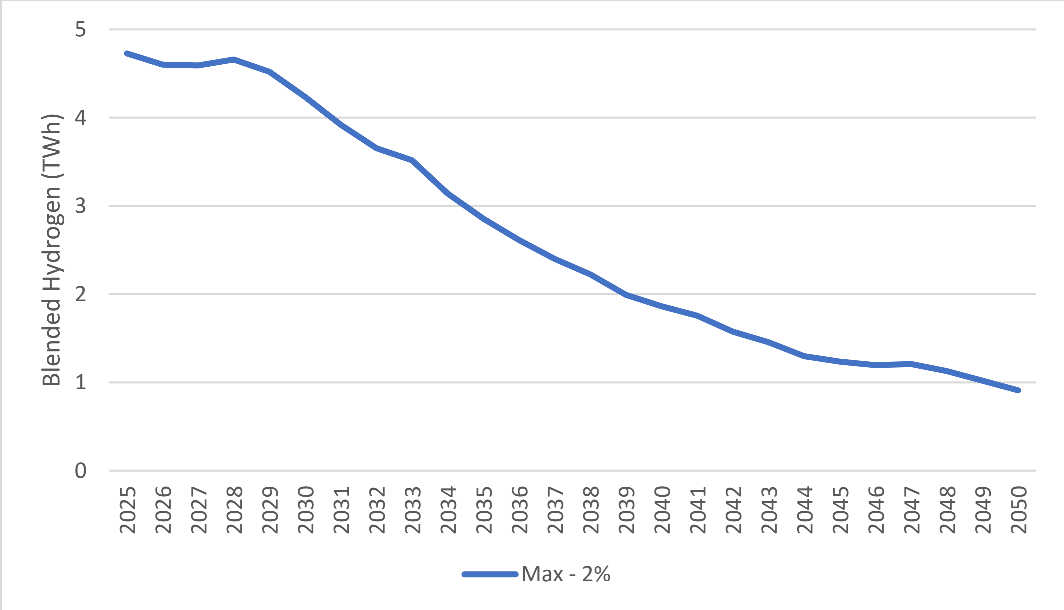
- Whether it would be possible to isolate blended gas within the NTS to protect sensitive end users; and
- What modifications might be necessary for NTS end users to accept blended gas and the practical feasibility and costs of these modifications.

The sections below detail, in order: monetised costs; non-monetised benefits; and non-monetised costs.

Monetised costs

Blended volumes

Figure 3: Potential volumes of blended hydrogen between 2025 and 2050 (TWh)



A graph showing the maximum potential volume of hydrogen in TWh which could be injected into the NTS from 2025 to 2050 if restricted to a hydrogen blend of 2% by volume. The volume is shown to decrease from ~4.7 TWh in 2025 to ~0.9 TWh in 2050 due to the expected decrease in overall gas volumes in the NTS, resulting in a proportionally lower volume of blended hydrogen.

This assessment concerns the economic impacts of a decision to allow hydrogen blending into the NTS of up to 2% by volume. In practice, if blending is to remain a flexible offtaker, then there will need to be less than 2% blended hydrogen in the NTS in general. Throughout this assessment we assume that both electrolytic and CCUS-enabled hydrogen can be blended.

As we are dealing with a much lower volume cap (2%) than with distribution-level blending, the overall volumes come out lower than for distribution blending despite the greater volume of gas circulating in the NTS. These figures also do not consider simultaneous distribution-level blending; in practice both transmission and distribution blending would be happening simultaneously. Potential blended volumes decline over time as natural gas and NTS use decline.

Enabling costs

Enabling blending into the NTS will require a) some upgrading of the network, primarily gas analysers and flow meters; and b) the construction and operation of injection point infrastructure connecting hydrogen producers to the NTS.

Hydrogen can be injected into the NTS at different locations, either through existing connections (with expansion and/or upgrade for hydrogen) or new ('greenfield') connections. For a given producer, the cost of doing this would have to be surpassed by any savings from blending for transmission blending to be an economically viable option for the producer.

These costs would primarily be the one-off Capex of constructing a given connection to the NTS, and then some ongoing Opex costs of maintaining and operating the injection point. These costs will be site-specific and depend on the type of connection used. Initially these costs would be incurred by NGT, the operator of the NTS, and then recovered from users via network charges.

NGT would also have to upgrade the infrastructure of the NTS to accept blended gas, mainly by replacing flow meters and analysers. The costs of this would be recovered from users via network charges.

Overall, NGT estimates these enabling costs to be c.£300m in total if all hydrogen production sites choose to blend; the actual costs could be lower if not all sites decide to blend. For hydrogen producers, if transmission blending were to go ahead and be taken up, this would be cost-neutral as their savings from reduced project financing costs (see section on Non-Monetised Benefits) would have to outweigh these enabling costs in order for them to proceed with blending. If they did not proceed, then most of the enabling costs would not be incurred as injection point infrastructure would not be required.

Non-monetised benefits

Bringing forward production

Like distribution blending, as an offtaker of last resort, transmission blending could play a role in managing the risk of hydrogen producers being unable to sell sufficient volumes of hydrogen. Blending may also help to mitigate cross-chain volume risks relating to the development of hydrogen transport infrastructure. In the initial absence of larger-scale T&S infrastructure, transmission blending could have value as a strategic enabler to enable electrolytic hydrogen producers to locate to support the wider energy system. This could be beneficial for electrolytic hydrogen producers located behind network constraints using excess renewable electricity that would otherwise have been curtailed.

We envisage that in certain circumstances these projects may have value in using blending as a majority offtaker from the outset on the basis they will transition to other hydrogen offtakers as hydrogen T&S infrastructure materialises.

Reduced project financing costs

Transmission blending being able to operate as a reserve offtaker would potentially reduce the riskiness of some hydrogen production projects by guaranteeing demand and hence revenue for the project. This reduced risk could in turn reduce project financing costs and so reduce the effective production costs for producers. To an extent, this benefit could be realised even if no physical blending in fact occurs, with the existence of transmission blending as an option de-risking hydrogen production projects.

Wider hydrogen economy

Blending could play a role to facilitate an optimised hydrogen economy both in terms of location of electrolytic production and minimising system costs and reducing investment risk into hydrogen production. It may also stimulate hydrogen supply chains and encourage increased investment into the UK hydrogen economy by improving investor confidence.

Curtailment

As mentioned above in the initial absence of larger-scale T&S infrastructure transmission blending could have value as a strategic enabler to enable electrolytic hydrogen producers to locate to support the wider energy system. This could be beneficial for electrolytic hydrogen producers located behind network constraints using excess renewable electricity that would otherwise have been curtailed, reducing electricity curtailment payments.

Carbon savings

Substituting natural gas in the NTS for low-carbon hydrogen, and this blended gas being used by NTS offtakers, will generate carbon savings by reducing the unabated use of natural gas.

Non-monetised costs

Stranded assets

As blending is time limited, given declining natural gas demand over time, there is a risk that transmission blending could leave stranded assets (like with distribution blending). Transport infrastructure built to move hydrogen to the blending injection point, and the injection point itself, may become redundant in time.

Incentivising inefficient location of production sites

As with distribution blending, transmission blending may incentivise production sites to be located where it is favourable for them to inject their hydrogen into in the NTS rather than where there is long-term hydrogen demand and offtakers. This could potentially be mitigated through the hydrogen funding allocation processes.

Value for money

There are other methods of supporting decarbonisation than hydrogen, in particular electrification. Given the potential costs of blending hydrogen in the NTS, electrification may be a more cost-efficient method of decarbonising an end user of natural gas.

NTS end user modifications

According to the Arup survey published alongside this consultation, many end users (offtakers from the NTS) indicated a need to, in some form, modify or upgrade their systems in order to accept blended gas. The Arup research gave each end user a score from 1-5 based on the site's potential ability to accept a hydrogen blend, between 1 (blending is possible at the current site, without modifications) and 5 (blending could not be achieved). Upgrades and modifications to accept blends will impose costs on these end users, who will not directly benefit from transmission blending. We do not have site-specific estimates of these costs. One site, which was rated a '3' in the survey, reported that upgrading its control systems would cost c.£10-15m. Given the user survey results, this – if representative – implies potentially significant modification and upgrading costs for end users as a result of transmission blending.

Separately, sites wishing to upgrade their systems will be required to go offline, potentially for extended periods of time, which will impose additional costs. Moreover, many NTS offtakers are power plants, and so them going offline or reducing generation would have implications for the power system. There are also indications that even with modifications power plants may need to reduce generation due to fluctuations in the composition of their gas input.

In addition to any direct monetary costs of infrastructure and systems modifications and upgrades, there will also be the need for end users to pay to conduct feasibility studies to determine what modifications would be necessary.

In the event NGT is able to isolate blended gas to protect sensitive end users, then these costs would (at least partially) no longer be relevant. There could be some additional Capex and Opex costs incurred by NGT to do this, which have not been estimated. It is not yet clear whether this is technically possible.

NTS end user deblending costs

Sites which are unable to accept blended gas under any circumstances will have to deblend their gas input to separate out the hydrogen from the natural gas. Deblending technology is unproven at scale and estimating its costs is therefore complex and highly uncertain.

NGT's Hydrogen Deblending Phase 2 Technical Report[15] estimated deblending costs to be in the range of £31.8-64.5 per 1000 cubic metres of gas input for deblending from 20% to <0.1%. This is, of course, different from the potential scenario considered here of deblending from 2% to <0.1%, though the cost implication is unclear. There is less hydrogen to separate out but more natural gas to process, and it is also more difficult to separate out lower proportions of hydrogen.

The Arup report published alongside this consultation used a range of deblending cost estimates provided by NGT to generate some high-level estimates of deblending costs for a range of archetypes including gas turbines, reciprocating engines and direct and indirect firing processes. This indicates deblending costs could be in the order of millions to tens of millions of pounds per site per year.

In addition, sites which deblend will then have to dispose of the hydrogen they have separated out, incurring additional costs.

Question 6.

a) We welcome feedback on the economic assessment presented and any further analysis on the costs and benefits of transmission blending.

b) Please provide any additional information on the costs of any required modifications or mitigations required for NTS connected sites to be able to accommodate a blend of up to 2% hydrogen by volume. If you do not currently have this information, how long do you expect it take to assess what mitigations might be needed and what the costs of these could be?

[15] National Gas Transmission (2023) 'Hydrogen Deblending Phase Two Combined Final Technical Report'

Consultation questions

1.
   a. **Do you agree with the assessment of the impacts of blending up to 2%, 5% and 20% hydrogen by volume on NTS end users?**

   b. **Are there any further operational and/or financial impacts on end users we should consider? Please provide evidence to support your response.**

2. **Do you agree that if transmission blending is enabled and commercially supported by government, the most appropriate mechanism would be via the HPBM? Please provide evidence to support your response.**

3. **Do you agree with our minded to position to allow both the gas transmission network operator and gas shippers to purchase hydrogen produced for blending? Please provide evidence to support your response.**

4. **Do you agree that working within the current gas billing arrangements will not result in an increase in billable usage and gas bills for end users connected to the NTS, should transmission level blending be enabled by government? Please provide evidence to support your response.**

5.
   a. **Do you agree with our minded to position to only consider further whether to support and enable transmission blending of up to 2% hydrogen by volume? Please provide evidence to support your response.**

   b. **Do you have any further concerns on enabling blending up to 2% hydrogen by volume into the NTS? Please provide evidence to support your response.**

   c. **Is there a maximum level of blend that would be feasible with minimum modifications for sites connected to the NTS? Please provide evidence to support your response**

6.
   a. **We welcome feedback on the economic assessment presented and any further analysis on the costs and benefits of transmission blending.**

   b. **Please provide any additional information on the costs of any required modifications or mitigations required for NTS connected sites to be able to accommodate a blend of up to 2% hydrogen by volume. If you do not currently have this information, how long do you expect it take to assess what mitigations might be needed and what the costs of these could be?**

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