CLEAN AIR TASK FORCE

Consultation Response: Hydrogen Blending into the GB Gas Transmission Network

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Source: https://energygovuk.citizenspace.com/energy-security/hydrogen-transmission-level-blending/consultation/intro/

Consultation questions

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

Answer:

Blending hydrogen into the National Transmission System (NTS) will affect all users of the gas network at the transmission and distribution levels across the UK, since gas distribution networks (GDNs) source their gas from the NTS. Therefore, when considering the costs versus benefits of hydrogen blending, the impact on users connected directly to the NTS and those connected indirectly through their local GDN should be taken into account.

Previous work has suggested that impacts on most end users at a 2% blend would be negligible. Within the Arup survey on the impact on users connected to the NTS, most sites indicated that an engineering study would be required to confirm any necessary upgrades. Such studies require funding, and even if they were not required, some level of work is necessary to ensure that OEM warranties on natural gas-powered equipment are not voided. All of this would impose a time and cost burden, and while only 30 sites responded to the survey, the number of sites that would need to assess the impact of a hydrogen blend would be significant, given that this would affect all gas network users. Some of the costs could be offset through running an education campaign, but even then, there would be a significant total expenditure to understand and mitigate the impacts of a hydrogen blend at a national level.

End users surveyed were concerned about the variability of the blend level. The planned use of hydrogen blending as an offtaker of last resort would result in varying concentrations of hydrogen, both geographically, depending on distance from the blending point, and over time, as natural gas flow rates vary seasonally [1]. This presents a particular challenge for gas network operators and end users, as concentrations of hydrogen could vary between 0% and 2% by volume over relatively short time periods, and equipment could not easily be optimised for one fixed gas specification. This could result in increased emissions as the burners operate with reduced efficiency, impacting both carbon emissions and air quality.

End users would need to invest in engineering studies and any required site mitigation measures, regardless of whether the upstream hydrogen producer injects into the NTS. This risks significant national expense and uncertainty for little benefit.

1. National Gas: Hydrogen Blends in the NTS a theoretical exploration, 2021.

1b. Are there any further operational and/or financial impacts on end users we should consider? Please provide evidence to support your response.

Answer:

Costs of hydrogen
Production costs for hydrogen in the UK are significantly higher than the cost of natural gas, with HAR1 awarded strike prices averaging £241/MWh. The cost implications for end users' gas bills would depend on the selected commercial arrangement. Unless the cost differential is fully passed on through the Hydrogen Production Business Model (HPBM), it will result in higher gas bills for end-users.

Costs for network improvements
As discussed in answer to question 1a, while the direct impact on users and network assets is likely to be minimal at a 2% hydrogen blend, some level of network change may be required. Currently, such costs are socialised across all network users, and unless a different financing model is implemented, the cost burden for any changes necessary to enable a 2% hydrogen blend may be borne by end users of the network.

This could include the cost of additional gas meters, which may be required for variable levels of hydrogen blend over time and across regions to ensure that each charging area has a representative CV for billing purposes [1]. There are other potential network costs, and work is ongoing under FutureGrid Phase 2 on compression and deblending (deblending is unlikely to be feasible at a 2% blend) [2]. Any reduction in compression efficiency or any additional infrastructure costs would result in an additional cost burden for consumers. Likewise, if specific, highly sensitive users require deblending, which would be challenging at a 2% blend, with the further complication of dealing with the deblended hydrogen, especially if the gas in the grid is already at a 2% hydrogen blend, it is unclear how these costs would be distributed.

This will also increase project costs, including for the grid connection, additional piping, and compression, which, depending on the scale of the hydrogen plant, could be significant. This is discussed further in response to question 6.

[1] ARUP: National Transmission System Hydrogen Blending Stakeholder Engagement Report, 2025
[2] National Gas: Future Grid Phase 2 Compression Progress Report, 2024

2. Do you agree that if transmission 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.

Answer:

We do not consider the HPBM to be an appropriate mechanism to support hydrogen blending into the NTS.

The role of NTS blending as an offtaker of last resort does not provide a meaningful solution to manage volume risk for projects under the HPBM. This is due to the high costs and complexities of establishing transmission connections, as well as the requirement for hydrogen projects to be located in proximity to NTS assets to access this route. The overall costs of enabling a 2% blend in the NTS would significantly outweigh the limited benefits of reducing volume risk for HPBM-supported producers.

The HPBM already incorporates a sliding scale approach to mitigate volume risk, and this mechanism could be adjusted further if evidence showed that volume risk was materially inflating strike prices in hydrogen allocation rounds. This would offer a more targeted and cost-effective means of support than enabling NTS blending.

The HPBM should consider other options for derisking projects, which may provide equivalent or better protection at a lower cost to the UK. Including a greater focus on stimulating demand rather than production and focusing hydrogen into regions where common infrastructure could be built, and multiple producers share the volume risk.

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.

Answer:

We agree that allowing both the gas transmission network operator and gas shippers to purchase hydrogen for blending could create a broader market. However, any mechanism must recognise and preserve the low-carbon credentials of hydrogen sales.

To achieve this, we recommend decoupling the certification of hydrogen from the physical product. By enabling purchasers to account for the environmental attributes of the hydrogen they buy—separately from the blended physical molecules—market participants would be incentivised to procure blended volumes of hydrogen, as these could contribute to mandated or voluntary emissions reduction targets. This approach would build on existing frameworks such as the Renewable Energy Guarantees of Origin (REGO) and Renewable Gas Guarantees of Origin (RGGO) schemes, which are already well understood by market participants.

5a. 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.

Answer:

We would not support the blending of hydrogen at any concentration into the gas network at the transmission or distribution level under the HPBM.

The UK should seek to collaborate with the EU and its member states to understand developments in the EU regarding hydrogen blending, including the likelihood and timing of natural gas incorporating a hydrogen blend arriving through one of the interconnectors. Maintaining a significantly different acceptable gas specification than EU partners may cause interoperability challenges, and international collaborative efforts could mitigate these.

Hydrogen blending is not a viable decarbonisation pathway
While it is recognised that this consultation does not focus on blending at 2% as a climate solution, CATF urges the UK government to consider the broader implications of putting hydrogen into the natural gas system. The abatement cost, whilst acceptable when being used in hard to abate sectors, should not be acceptable when blending into the gas network.

At 2%, hydrogen blending would reduce the emissions of the received gas by just 0.62%. These emissions savings could be offset by any subsequent reduction in burner efficiency caused by a variable gas supply; in the worst case, emissions could increase and air quality decrease as a result of a variable blend. This would be a highly inefficient use of a valuable resource with limited climate benefits. Deployment of low-carbon hydrogen should be prioritised in 'no regrets' end-use sectors where there are simply no other decarbonisation options or where alternatives are less feasible, either technically or economically.

Blending itself does not represent a long-term solution for mitigating climate change, as the use of unabated natural gas should be phased out, reducing the volume of gas that can be blended.

The costs do not outweigh the benefits
Supporting hydrogen blending at 2% at the transmission level under the HPBM as an offtaker of last resort would not outweigh the costs that existing users of the gas network across the UK would face due to this change in gas specification. The work required of OEMs and site operators to understand any potential impacts could be significant, and the cost burden would quickly add up when applied to all users across the UK.

This must be weighed against mitigating Volume Risk for a small number of HPBM-supported projects, for whom injection into the gas network cannot be a priority, given the HPBM's role as an offtaker of last resort. Additionally, there are significant challenges for hydrogen projects seeking to inject into the transmission network, which could limit the volume risk mitigation that could be achieved. Further details of these challenges are provided in response to question 6.

[1] National Gas: Future Grid Phase 1 Closure Report, 2024
[2] National Gas: Future Grid Phase 2 Compression Progress Report, 2024

5b. 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.

Answer:

Reducing network capacity risks increasing emissions from backup fuels. Blending hydrogen into the gas network at 2% by volume would increase the required gas volume by 1.4% to maintain the total energy content. This would impact both the storage capacity of natural gas and the network's transportation capacity. Some regions of the UK gas network are already capacity constrained. As a result, some industrial end users are on 'interruptible contracts', which constrain their consumption over winter. They therefore use a backup bunkered fuel supply, typically kerosene, during these months, which has significant associated emissions.

Even a slight reduction in the supply of natural gas to these facilities would make them more reliant on backup fuel options, which would swiftly negate any potential environmental benefits of hydrogen blending.

5c. 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.

Answer:

N/A

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

Answer:

Blending at 2% as an offtaker of last resort does not mitigate volume risk for hydrogen project developers. This is due to several challenges faced by hydrogen project developers, summarised below:

1. **Access to NTS infrastructure**

For blending to be an appealing backup offtaker, the production site would have to be relatively close to existing NTS assets. This is unlikely to be the case for most projects, and National Grid estimates that connection costs increase by £2m per km of additional required pipeline in ideal conditions [1]. This would quickly become prohibitively expensive for most projects.

2. **Timeline and costs of a transmission connection**

Applications for transmission connections typically take around 36-42 months from application to connection, with significant upfront application fees [2]. The applicant must cover the infrastructure costs required, estimated at ~£2m for a non-standard design on a greenfield site, excluding any additional pipeline length. There would be further costs for the required blending infrastructure to ensure a proper hydrogen-natural gas mixture and to regulate the hydrogen flow, to ensure that the 2% blend is not exceeded, which may be costly [3]. There are also ongoing operational costs associated with a transmission connection, even when it is not in active use.

Therefore, hydrogen projects would have to commit to the capital and ongoing operational costs upfront in case customer demand for hydrogen declined, or apply once this event seemed more certain. In the latter case, there would be a significant delay between customer demand declining and demand from blending coming online.

3. **Hydrogen blending cannibalisation risk**

Hydrogen blended at an individual site would not result in an even mix across the country but would instead be mixed with the gas flowing past that location. Suppose another hydrogen project were to be developed and blend hydrogen upstream of that. In that case, projects risk the passing of natural gas being already saturated with hydrogen, which would reduce the acceptable volume of hydrogen they could inject into the NTS.

For blending to be a credible volume risk mitigation measure as an offtaker of last resort, projects would need to be guaranteed blending capacity. It is unclear how this would be managed if hydrogen projects had not committed capital to making the connection, but instead wanted to retain this option for the future.

4. **Hydrogen volume enabled by blending**

Natural gas demand and flow through the NTS is highly seasonal, with demand peaking in winter and diminishing greatly in Summer. This would significantly change the acceptable volume of hydrogen for blending throughout the year. Likewise, natural gas flow rates are dependent upon location; for example, St Fergus is a major natural gas terminal supplying around one third of total UK natural gas demand, and with a very high natural gas throughput, it represents one of the largest potential sites for blending in the UK. Blending at 2% into all the natural gas processed at this terminal could be enabled by 110MW of hydrogen production capacity in summer and 250MW in winter [4], a relatively modest requirement compared to the UK's current hydrogen deployment ambition. At other locations, which are typically smaller in scale, 2% blending would not create a substantial hydrogen demand for most projects.

5. **Additional project requirements**

The National Transmission System (NTS) operates at 70 bar; most electrolysers operate at atmospheric pressure or, at most, produce hydrogen at 30–40 bar. For hydrogen projects to inject into the NTS, additional compressors would need to be installed, incurring further costs and complexity, despite the potential for it never being required. These compressors would need to be kept with an inert gas when not in operation, meaning that they couldn't instantaneously come online and would have to vent the hydrogen after use.

[1] National Gas: Connection Charging Statement Revision No.15, 2025

[2] National Gas: Gas Connection Application Guide, 2025.

[3] ARUP: National Transmission System Hydrogen Blending Stakeholder Engagement Report, 2025

[4] Pale Blue Dot, Aberdeen Vision Project, 2020.

6b. 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?

Answer:

N/A