By email: hydrogentransportandstorage@energysecurity.gov.uk

Uniper UK Limited

Compton House
2300 The Crescent
Birmingham Business Park
Birmingham B37 7YE
www.uniper.energy

Uniper

Registered in
England and Wales
Company No 2796628

Registered Office:
Compton House
2300 The Crescent
Birmingham Business Park
Birmingham B37 7YE

Response to: Hydrogen blending into the GB gas transmission network

16 September, 2025

About Uniper

Düsseldorf-based Uniper is a European energy company with global reach and activities in more than 40 countries. With approximately 8,000 employees, the company makes an important contribution to security of supply in Europe, particularly in its core markets of Germany, the UK, Sweden and the Netherlands.

Uniper's operations encompass power generation in Europe, global energy trading, and a broad gas portfolio. Uniper procures gas—including liquefied natural gas (LNG)—and other energy sources on global markets. The company owns and operates gas storage facilities with a total capacity of more than 7 billion cubic meters.

Uniper intends to be completely carbon-neutral by 2040. Uniper aims for its installed power generating capacity to be more than 80% zero-carbon by the early 2030s. To achieve this, the company is transforming its power plants and facilities and investing in flexible, dispatchable power generating units. Uniper is already one of Europe's largest operators of hydropower plants and is helping further expand solar and wind power, which are essential for a more sustainable and secure future. The company is progressively expanding its gas portfolio to include green gases like hydrogen and biomethane and aims to convert to these gases over the long term.

Uniper is a reliable partner for communities, municipal utilities, and industrial enterprises for planning and implementing innovative, lower-carbon solutions on their decarbonisation journey. Uniper is a hydrogen pioneer, is active worldwide along the entire hydrogen value chain, and is conducting projects to make hydrogen a mainstay of the energy supply.

About Uniper in the UK

In the UK, Uniper owns and operates a flexible generation portfolio of power stations, a fast-cycle gas storage facility and two high pressure gas pipelines, from Theddlethorpe to Killingholme and from Blyborough to Cottam. We also have significant long-term regasification capacity at the Grain LNG terminal in Kent, to convert LNG back to natural gas.

Summary:

- The assessment presented is insufficient to inform a decision on hydrogen blending into the GB transmission network.
- There are both cost and operational implications for electricity and gas supply; due to many sensitive NTS connected users.
- Hydrogen blending into the distribution network could provide the transitional approach to mitigate risks in hydrogen production, alongside direct investment to develop dedicated hydrogen pipelines and storage infrastructure.

Q1a. Do you agree with the assessment of the impacts of blending up to 2%, 5% and 20% hydrogen by volume on NTS end users?

The assessment of the impact of blending presented in this consultation is based on the Arup study, which relied on a voluntary survey of NTS connected sites and users. This study does not provide sufficient evidence to inform government decision-making. More comprehensive assessments are necessary to evaluate the costs, feasibility, required adaptations, and potential disruptions for current NTS end users, particularly those with hydrogen-sensitive infrastructure, such as power generators and gas storage operators. It is expected that these costs will be significant. Without a clear and consistent government policy, investment in feasibility studies and infrastructure modifications will be challenging to justify.

In addition, concerns remain regarding the potential impact on asset integrity related to storage at varying levels of blending. The compressibility and energy density of hydrogen results in a reduction in total energy storage capacity. As a result, this could adversely affect the on-going economic viability of storage facilities, especially throughout the transition period.

Q1b. Are there any further operational and/or financial impacts on end users we should consider? Please provide evidence to support your response.

In principle, the narrower scope should make it clearer what assessments and evidence are needed. However, with the lack of clear policy direction, we are rightly concerned about the potential significant costs of those assessments with no discernible benefit for existing users of the NTS.

From a power generation and combustion perspective, concerns increase with higher hydrogen content, and preliminary site studies indicate even 2% blends may require significant modifications and costs. Technical challenges also arise for gas turbines: variable hydrogen blends can impact machine starting and shutdown processes, and even small amounts of hydrogen can significantly affect the gas quality (in particular, the Wobbe Index), possibly making some gas supplies unsuitable for turbines. Further work with equipment manufacturers is needed to determine safe blending levels and rates of change in gas quality.

From a gas storage perspective, introducing hydrogen blends raises the risk of steel embrittlement, which could damage equipment and potentially cause unsafe leaks. Because these facilities operate in a high-pressure cycling environment, the risks increase over time. To mitigate them, additional safety measures and more frequent maintenance checks are needed, but this also raises operational costs and asset downtime.

As a minimum the site would have to undergo a full hazard and operability study (HAZOP) to ensure all equipment and safety systems were still fit for purpose. Depending on study findings, this may lead to a number of plant modifications and subsequent additional costs.

A key financial issue highlighted is the risk that costs from hydrogen blending, if funded through the Hydrogen Production Business Model (HPBM) and Gas Shipper Obligation (GSO), would be passed directly to consumers, raising energy bills.

In conclusion, while hydrogen blending is seen as a transitional measure, it brings notable operational, technical, financial, and regulatory challenges, which are elevated at transmission level, due to the significant number of sensitive users, consuming large volumes of gas, and which are key to ensuring security of supply in both gas and electricity markets. A clear government policy, transparency on various impacts, and further technical guidance are needed to address these issues effectively.

Q2. 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.

We cannot currently support the hydrogen blending into the GB gas transmission network. However, if it's enabled and commercially supported by government, we broadly agree with the idea of using the existing, known and tested mechanisms. From that perspective, the existing HPBM seems to be the most practical approach.

However, even with the use of HPBM, some adaptations will be required to address at least the following issues:

- addressing current Risk-Taking Intermediary (RTI) restrictions that prevent shippers (and networks) from being eligible offtakers for hydrogen including blended hydrogen;
- clear guidance on how the HPBM integrates with other agreements like the Low-Carbon Hydrogen Agreement, especially regarding technical requirements and metering.

Allowing blending into the gas networks can reduce investment risk and help projects reach financial close by providing a guaranteed, if limited, offtake route. This support is important in the early stages of developing the hydrogen market, alongside the crucial investment in dedicated hydrogen infrastructure. Once that infrastructure becomes available, the benefits of blending will diminish. However, there are, some important differences between blending into distribution and transmission network. Blending into the distribution network provides an opportunity to de-risk projects, without significant sensitive sites being negatively impacted. At the transmission level, the costs and risks to NTC connected sites and users currently outweigh the benefits of blending mentioned above.

Q3. 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.

We do not support the hydrogen blending into the GB transmission network, although broadly agree with the proposal that both the gas transmission network operator and gas shippers should be permitted to purchase hydrogen for blending under the HPBM. Furthermore, clear commercial rules should be established to define purchasing and selling processes for blended hydrogen, the terms of sale, and entry capacity. The introduction of a *"buyer of last resort"* might be necessary to guarantee that hydrogen producers have consistent access to the network.

In addition, achieving cost parity between blended gas and natural gas would be important to ensure sufficient participation incentives. Therefore, making both parties eligible could enhance market access and efficiency; however, this will primarily depend on transparent commercial structures and pricing.

Q4. 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.

In general, using the current gas billing arrangements for hydrogen blending at the transmission level should not lead to higher billable usage and gas bills for NTS end users. However, this depends on monitoring for possible increases in calorific value (CV) shrinkage, which would affect costs, and these would be spread across all NTS flows.

From a combustion perspective, the acceptable level of hydrogen to be safely added to natural gas depends on the types of gases already present. If the natural gas has a lot of heavier components like ethane, propane, or butane, even a small amount of hydrogen could be too much. In some cases, it may not be safe to add any hydrogen at all. Without limits on adding hydrogen to these richer gas mixes, some gas turbines may not work properly with the fuel.

With similar caveats noted in our responses to questions 2 and 3 above- while current systems seem adequate, the funding approach for the hydrogen market is still under review. Therefore, continued clarity on funding and policy changes is essential to ensure metering and billing remains accurate.

Q5a. 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.

We do not support the minded to position. The government has not adequately assessed the cost of blending even small hydrogen amounts at the transmission level. The impact on sensitive assets connected to the NTS has not been properly evaluated. This should be addressed before any final decision is made.

Q5b. 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.

Enabling blending up to 2% hydrogen by volume into the NTS presents a significant number of technical complexities and will result in significant costs. Those decisions must be supported thorough technical and cost analysis, ensuring alignment with equipment capabilities and billing systems.

From a technical perspective, evaluating the feasibility of incorporating up to 2% hydrogen by volume for gas turbines necessitates manufacturer or experimental validation tailored to each turbine model and configuration. Additional technical challenges persist, especially concerning the dependable operation of turbines using hydrogen-enriched gas.

Similar evaluations are essential for gas storage infrastructure, with particular focus on maintaining asset integrity. As mentioned above, the compressibility and energy density of hydrogen results in a reduction in total energy storage capacity. As a result, this could adversely affect the on-going economic viability of storage facilities, especially throughout the transition period.

Q5c. 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.

No. Determining the appropriate maximum blend level for generators and storage operators has to be conducted through comprehensive evaluation by the original equipment manufacturers (OEMs), with associated costs factored into the process. Furthermore, in the absence of detailed modelling of blended hydrogen flow within networks, this assessment becomes more complex and may result in unnecessary adjustments to offtaker equipment.

We expect equipment changes for any blend, with substantial modifications required at, and above 5%.

For clarity, while we cannot currently support the hydrogen blending into the GB gas transmission network, we also can’t support any future phased approach to increasing blend limits, as each increase would require a dedicated round of technical assessments and equipment upgrades.

Q6a. We welcome feedback on the economic assessment presented and any further analysis on the costs and benefits of transmission blending.

The economic assessment has identified relevant topics, but further analysis on the costs and benefits of transmission blending is required to inform any final decisions. The current economic analysis does not fully address end user cost implications, and site-specific assessments are needed for accurate estimation of equipment modification costs.

Additionally, consideration should be given to both non-monetised benefits (such as carbon reductions from hydrogen blending) and non-monetised costs (including risks associated with stranded assets and inefficient siting of production facilities), along with the following aspects:

- evaluating whether blending remains preferable compared to direct investment in dedicated hydrogen pipelines and storage infrastructure;
- examining alternative risk mitigation strategies for hydrogen projects, such as contractual break clauses in response to increased commercial complexity;
- developing detailed safety, technical, regulatory, and commercial frameworks;
- protecting hydrogen value after blending through approaches such as certification schemes;
- addressing local issues encountered by transmission-connected offtakers, referencing existing practices (e.g., oxygen flow management for sensitive sites) and regional differences in blending capacity;
- identifying systemic synergies and pathways for market development; and
- exploring opportunities for job creation and economic growth.

Finally, the analysis suggests that hydrogen blending volumes may decrease gradually towards 2050, in line with an anticipated shift to dedicated hydrogen networks. However, there is currently no established strategy for managing this transition or aligning it with renewable energy integration.

Q6b. 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?

Modifications or mitigations needed for NTS connected sites to accommodate up to 2% hydrogen by volume cannot yet be fully determined, as detailed assessments and input from OEMs are still required. In addition, site-specific studies would be needed to establish what changes and costs would be involved. As mentioned above, without a clear and consistent government policy, investment in feasibility studies and infrastructure modifications will be challenging to justify.

High demand for OEM expertise means that feasibility studies can take one to two years to complete. If modifications are ultimately required, indicative preliminary quote suggest costs could be between £2 million and £3 million per gas turbine.

Lastly, before any decision is made, government needs to be fully convinced that there are no risks to either gas or electricity security of supply any levels of hydrogen blend into the NTS. We do not believe it will be in this position until it has examined the impacts on NTS users in more detail than the Arup study provided.