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Response to: Hydrogen Blending into GB Gas Distribution Networks

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Düsseldorf-based Uniper is an international energy company with activities in more than 40 countries. The company and its roughly 7,000 employees make an important contribution to supply security in Europe, particularly in its core markets of Germany, the United Kingdom, 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 2030. 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.

In the UK, Uniper owns and operates a flexible generation portfolio of seven power stations and a fast-cycle gas storage facility.

Consultation Response

We have set out below our answers to the consultation questions. Our views in summary:

- Blending could play an important role in supporting hydrogen production in the early days of market development.

- Certificates for hydrogen blended into the gas network should be tradeable: without commercial value for secondary markets there is no driver for shippers or networks to purchase or accept hydrogen for blending.

- Hydrogen blends of over 2-5% are likely to require changes to grid-connected assets, which will incur costs and may require coordination.

Our views in full:

- **Question 1.**

Uniper operates five power generation gas turbines in the UK, firing natural gas. Our current fleet are all connected at gas transmission system level, although, in the past, we have operated gas turbines connected to the distribution networks. Our responses to Question 1 are based on our recent transmission system level experience, but would equally apply if we had distribution level connections.

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

Yes. We think most gas turbines will be able to operate at blends of approximately 2-5% by volume with no or minimal change to plant or control systems. However, beyond this, we have concerns about useability and equipment integrity. Gas turbines have operating practices and control systems that do not allow operation under unsafe conditions, and these are designed to accept the current fuel composition.

Adding hydrogen to natural gas increases the reactivity of the fuel, leading to an increased risk of unacceptable NOx emissions, combustion dynamics and flashback. Gas turbines are “tuned” to ensure acceptable NOx emissions and combustion dynamics. It is unlikely that typical gas turbines will be able to operate over the full range of allowable natural gas compositions with the full range of 0 to 20% hydrogen addition without re-tuning.

At blends of up to 20% there should be no need for changes to instrumentation and electrical equipment located within the designated hazardous zones, but the changed properties of the gas may have an impact on plume size, and thus the extent of the hazardous zone.

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

Variation of fuel composition is a major concern for gas turbines, which are tuned to optimise performance, emissions and combustion dynamics. Blends will need to be kept within narrow ranges to avoid operational issues and plant outages.

The forthcoming (April 2025) reduction in minimum Wobbe Index allowed under the GS(M)R will allow fuel variability of about ±5% about the mid-point fuel – which should permit hydrogen blends of up to 20%. This is close to the limit of acceptability for many existing gas turbines, however, so there is little scope for additional variation without upgrades to much of the existing fleet.

The impact of the change in chemical properties (i.e. reactivity) of blending hydrogen into natural gas is more difficult to quantify, but can be approximately characterised by the concentration of components that are more reactive than methane. In natural gas this can be represented by the concentration of hydrocarbons containing more than one carbon atom – referred to as C2+. The C2+ content of UK natural gas varies between about 2-15%, but typically individual sites see less variation. At the extremes of current variation, issues relating to fuel reactivity are experienced, e.g. flame stability, dynamics, emissions, and in extreme cases component damage. Hydrogen is significantly more reactive than methane, so it is unlikely that any current gas turbine would be able to accommodate the full range of reactivity variation caused by varying from 0-20% hydrogen, even if it could be tuned to utilise a specified amount.

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

Yes.

Deblending, is unlikely to be efficient or cost effective for our gas generation plant, and therefore we have not assessed the costs of deblending equipment and processes.

It is likely that most of our plant would be able to accommodate blends with up to 5% hydrogen without significant upgrade costs but the gas turbines would need to be re-tuned. Establishing the settings required is a time-consuming and skilled activity normally undertaken by the OEM's engineers. This would cost in the order of £100,000 per turbine.

If upgrades are required the costs could be considerably more substantial. Key costs include:

- Re-assessment of hazardous areas and possible changes of equipment due to increased zone extents. Costs for this are difficult to estimate but could be of the order of £100,000 per unit.

- OEM assessment of starting capability – currently most gas turbines cannot be started with blends in excess of 5-10% hydrogen. If an alternative starting fuel is required a combustion system upgrade would be required and provision of a full alternative fuel system, including fuel storage, would be needed. Based on similar upgrades in the past, a rough order of magnitude estimate would be £6m per unit.

- If the combustion system cannot operate on a high hydrogen blend then, at a minimum, a combustion system upgrade and the implementation of a hydrogen-capable auto-tuning system would be required. Based on similar upgrades in the past, a rough order of magnitude estimate would be £5m per unit. If only controls upgrades with the implementation of hydrogen ready autotuning were required then the cost may be in the order of £2m per unit.

There may also be commercial costs associated with operating on a hydrogen blended fuel, especially toward the 20% end of the range. The use of hydrogen blends at the upper end of the range will need to be reflected in already agreed commercial arrangements such as Capacity Market agreements and the LCHA to account for the impacts on plant of less energy dense fuel, which may require generation units to be derated and affect the ability of CCUS enabled hydrogen production plant to reach target capacity.

These costs are based on large power generation gas turbines (~300MW class) that are more likely to be connected to the transmission network: for smaller plant (~30MW class) connected to the distribution network, evaluation and tuning costs will be similar, but equipment cost will be approximately 25% of large plant costs.

As site conditions and plant differ significantly a site by site evaluation would have to be performed. Uniper has five gas power generation sites operating a total of 13 gas turbine units. An initial survey of each site would cost upwards of £15,000, with a detailed assessment including input from the OEM being significantly higher.

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

The time required will be different for different sites/units depending on the amount of work needed to accommodate the proposed changes. If hardware upgrades are deemed necessary, these would normally be planned to occur at the next major gas turbine overhaul, which typically occur at about 3-4 year intervals. Changes to control systems (without hardware upgrades) can be more readily implemented and could be implemented on a shorter timescale. Plant requiring a significant combustion system upgrade would need longer, as such upgrades would need to be synchronised with a major overhaul: around 4-6 years.

It is also worth noting that many OEMs are quoting very long lead times for “standard” components of up to 24 months. If all GT operators in the UK were required to apply upgrades at the same time, then the timescales could conceivably be longer due to resource/engineering/manufacturing constraints in the wider market.

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

There is a wealth of evidence available about the impacts on natural gas fired electricity generating turbines: a good starting point is the ETN Global summary report: Addressing The Combustion Challenges Of Hydrogen Addition To Natural Gas[1]

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

In addition to our fleet of gas turbines, Uniper operates a fast-cycle natural gas storage facility at Holford, which is also connected to the GB gas transmission network.

[1] ETN-Summary-Report-Combustion-challenges-of-hydrogen-addition-to-natural-gas-Nov2022.pdf

Fast-cycle storage facilities run with a set of process parameters that present some specific challenges with regards to hydrogen blends. Most notably, we regularly cycle from high to low pressure (110 to 40 barg) across a wide range of temperature and moisture content. We have undertaken detailed work on the tolerability of different hydrogen blends in these process conditions across all components of the existing facility. The overall conclusion of this work is that significant investment (up to several millions € per site) in replacement components would be required to maintain operation of the facility and its process safety at blends greater than 2%. If useful, we would be happy to share more detail on the technical analysis completed to date.

We recommend detailed cost studies are undertaken ahead of any decision in order to understand the true impact of blending on assets associated with the transmission network.

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

We agree that blending hydrogen into natural gas networks will play a transitional role and that it should be the reserve offtaker for hydrogen producers, but we do not agree that this means that there should not be any commercial value in blending. Blending will support the development of the hydrogen market more broadly than just as an offtaker for producers; it will also support the development of a robust hydrogen shipping market, which will support producers by opening new markets to them and reducing the cost of finding new offtakers. If there is no commercial value in blending for shippers and/or gas distribution network operators (GDNOs), there is no rationale for them to purchase or accept low carbon hydrogen from producers, which would mean that in practice blending would not happen.

There will be routes for government to ensure that blending plays the role of reserve offtaker for producers without undermining the value case for other market participants, such as limiting the return to producers for hydrogen sold for blending to just the strike price – precluding any gainshare for producers.

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

Yes. Hydrogen producers will already be being recompensed through the Low Carbon Hydrogen Agreement (LCHA), so commercially supporting sales of low carbon hydrogen for blending in the same way as all other sales will be straightforward and will reduce administrative costs for producers.

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

We fully support allowing gas shippers to purchase hydrogen for blending. Permitting sales of low carbon hydrogen to risk-taking intermediaries, such as shippers, is a critical step in growing the market and de-risking hydrogen production.

We support allowing GDNOs to purchase hydrogen for blending as the purchaser of last resort, only when there is no other market interest. Allowing GDNOs a freer role in the market would lead to regulated monopolies competing with other market participants, which would decrease the size of the competitive market and have distortive impacts on market pricing and participant behaviour.

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

No. Whilst we agree that the gas network should play the role of reserve offtaker for producers, we do not agree that other players in the blending market should be prevented from deriving additional value from low carbon hydrogen. If there is no commercial value for shippers or networks in purchasing and blending hydrogen into the gas network, there is no reason for them to do it.

Certificates for hydrogen that is blended into the gas network should be treated in the same way as Green Gas Support Scheme certificates. This will support the development of a robust secondary market for low carbon hydrogen.

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

We agree with the free-market approach, but note that without regulatory change it is non-transparent and could be a barrier to blending. At present, connecting to gas distribution networks is almost entirely unregulated: there are no upfront costs or timescales available and connection costs and times are uncapped. There are defined connection protocols for the gas transmission network and significantly more information available to prospective connectees: something similar would need to be adopted for the distribution network to enable low carbon hydrogen project developers to assess whether blending is a practical outlet for their hydrogen.

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

We are not currently considering connecting to a gas distribution network for the purpose of blending, as blending is not permitted under the LCHA. If blending is permitted, we may consider connecting our proposed CCUS-enabled production facility in the Humber, the Humber H_2ub, to the network node at Thornton Curtis: as one of the biggest nodes on the distribution system, this should be well placed for blending hydrogen into the existing system gas. We have not discussed this option with National Gas.

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

Yes, this seems a pragmatic approach.

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

The economic analysis is at an early stage and further work needs to be done to understand the practicalities, commercial implications, and impacts on grid-connected assets of hydrogen blending before a more developed economic assessment can be carried out.

We would question a number of the assumptions that underpin this economic analysis, such as whether blending will happen without any commercial value for secondary markets, the ease and speed of grid connections and the implications this has for reducing project risk and unlocking investment, and the extent to which an electrolytic project could economically run on just curtailed electricity.