REA response to DESNZ Consultation on Hydrogen Blending in the Gas Distribution Network.

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the consultation on Hydrogen Blending in the gas distribution network. We have and continue to engage with the energy department on a wide range of hydrogen and related policy. It should be noted that a number of our members are particularly interested in production pathways other than electrolysis or methane reformation and we have engaged in detail on these 'alternative' pathways.

The REA represents industry stakeholders from across the sector and includes dedicated member forums focused on green gas & hydrogen, biomass heat, biomass power, renewable transport fuels, thermal storage, and energy from waste (including advanced conversion technologies). Our members include generators, project developers, heat suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 500 corporate members of the REA, making it the largest renewable energy trade association in the UK.

The discussion on hydrogen blending is particularly welcomed by the REA members and as such we published our position on hydrogen blending in a combined report with Hydrogen UK back in Dec 2022. In the report we set out the key potential benefits of hydrogen blending which are summarised as follows:

- **Stimulate Demand** – Hydrogen blending breaks the historical 'chicken and egg' between hydrogen supply and demand, by enabling the existing energy system to unlock hydrogen demand and support production.
- **Promote Investment** – Blending makes projects more investible as hydrogen producers are looking for ways to de-risk off-taker demand.
- **Meet Carbon Budgets** – Material environmental benefits are possible without significant hassle or disruption to contribute to achieving the 5th and 6th carbon budgets.
- **Optimise Production** – The gas network is able to store large quantities of energy and can act as a flexible off taker to balance hydrogen production with demand, enabling production to be ran at optimum load factors.
- **Provide Power Demand Flexibility** – Blending can reduce excess renewable electricity being curtailed and could provide one of the lowest cost use cases of hydrogen.
- **Build Social Acceptance** – Hydrogen blending can act as a strategic test case of social acceptance and market frameworks, enabling evidence to be gathered to better inform the 2026 strategic decision on hydrogen heating.
- **Maintain Safety** – All the evidence collated across trials demonstrates the safety of hydrogen blending.

In addition to our response below we would like to take the opportunity to urge the decision on this consultation to be made without delay and by the end of 2023. This will allow the progression of projects and certainty for developers and provide confidence for projects to apply under the HAR2.

We are also encouraged by the inclusion of both the distribution and transmission networks in this consultation. The REA believe the decision on blending is important to help progress the market and the inclusion of both networks will allow the flexibility for hydrogen injection. It will be important that if the decision on blending in the transmission is to be made outside of this consultation that it is also made as soon as possible (no later than 2024).

Consultation questions

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

REA are aware of the work being carried out by industry and government, which includes extensive involvement by members on the implications of blending and the related revisions to current gas safety management regulations. The work of the HyDeploy project, has been acknowledged in the consultation and related workshops. It was also noted that the project is due to submit the comprehensive safety evidence to the Health and Safety Executive (HSE) regarding the safe implementation of hydrogen blends in the GB distribution system and therefore it would be advisable to refer to that evidence in regard to safety or usability information.

The REA are aware that in the HyDeploy project, two phases of demonstrations, involving (in total) ~800 domestic properties have been conducted, and received two hydrogen exemption certificates. This is a strong indication that blending up to 20% can be considered safe into domestic properties. But as previously mentioned it would be prudent to wait for the completion of the ongoing third phase of the HyDeploy project, which is addressing safety aspects, including evaluating higher-pressure networks and connected gas users in the industrial and commercial sector.

REA are aware members will be providing more extensive details on these projects in their consultation responses, but indications are that the process should not raise any concerns up to this volume. It is also recognised that it will be up to the HSE to decide on safety matters. We are unaware of any particular issues for industry from the blended gas, however its recognised from previous work to inject biomethane into the gas grid and the move to hydrogen ready equipment that not only is industry able to make changes where needed, the lead in time for blending could effectively be communicated to those affected to make adequate changes if and where required.

However, it should be noted that some of our members are involved in the transportation of bio CNG or compressed natural gas which is extracted from the gas grid and therefore would be affected by blending above 2% v/v. The impact would be on the ability for the relevant fleet to accept the blended gas and this would also potentially affect the bio-compressors. There may also be some concern about gas engines where they produce back up generation without readjustment so if this were to be introduced a gradual ramp up of blend volume would be helpful but would also be expected as the hydrogen market develops.

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

As mentioned in the response to the previous question, there is a strong indication that the blending up to 20% can be considered safe into domestic properties and the REA are unaware of any particular issues for industry from the blended gas, so should be similar across the distribution network. In addition, its recognised from previous work to inject biomethane into the gas grid and the move to hydrogen ready equipment that, not only is industry able to make changes where needed, the lead in time for blending could effectively be communicated to those affected to make adequate changes if and where required.

However, a significant part of the HyDeploy project has been to understand the impact on variable percentage and REA understand that the Wobbe index of incoming gas can play a more significant impact on the operation of equipment. It would be in this area where the potential impact for variable percentage is possible, requiring more 'control' on ensuring the appropriate range of the Wobbe index or fundamental gas property may be needed to ensure there is no detrimental impact on any systems and technology.

It is not believed to be a concern for the overall gas network and the REA understand work is currently underway on evaluating potential impacts.

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)?

As a trade association, the REA would not itself be impacted by blending however as our members are producers or distributers of hydrogen, costs would be more significant if a brand-new network was to be required to support 100% hydrogen and the delays this would have on production delivery. Therefore, it is expected that costs would be significantly less than without blending.

Regarding hydrogen blending, it should be noted that, as our response to question 1A, some of our members would have equipment that would/may need to be changed to manage a change of 20% hydrogen blend. However, as the system is likely to `ramp up` in a similar way to the biogas (biomethane) when it was first introduced the equipment that may be affected such as transportation trucks, compressors, gas engines for back up and CCGT would have time to change over a prolonged period which may tie in with a natural replacement and upgrade programme.

Work by gas network members also indicates that most equipment would be able to cope up to the proposed 20% volume blend, falling in the same group as natural gas. REA understand that HyDeploy is also establishing an asset register to support a comprehensive review of connections to the relevant network and there is recognition a thorough assessment would be a basis for appropriate cost evaluation.

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?

As already responded to question 1A-C, some of our members would have equipment that would/may need to be changed to manage a hydrogen blend of up to 20% and there may be other equipment that would be impacted by variable volumes. It would therefore be dependent on how long those periods of change would normally be programmed and how quickly production of hydrogen was ramped up and affecting volumes. However, it is expected that the initial period of lower blending would allow for enough time to monitor the progress and impact.

The impact may be more in ensuring all the relevant safety outcomes from the Health and Safety Executive (HSE) review. Findings from this review could impact on the time required and affect the response to this question.

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

REA are a trade association so have not responded to this 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.

The REA has members that already manage blending of biomethane into the grid the distribution networks and there can be difficulties based on capacity – where there have been reports that as much of 50% of the time biomethane injection is limited due to capacity as a result of lack/reduction in local gas demand. If this is a current issue for biomethane than it's anticipated the situation would be the same/worsen for hydrogen production. The gas demand is also heavily reliant on seasonal demand and will depend on the region/ network.

Therefore, a consideration of injection into the transmission network would help alleviate the capacity constraints, and due to the much-increased flows, allow more plants the opportunity to have more injection points whilst also allowing for a better ratio and uniform blend. This will be particularly important whilst the hydrogen market is in a period of early operation, allowing de-risking benefits.

As the transmission system is not governed by the Flow Weighted Average Calorific Value (FWACV) billing methodology, this would also have the benefit of addressing the impact of CV billing resulting from GDN blending. The impact of the latter would also increase over time if continued blending is needed. An additional benefit would be a change in the requirement for adding propane to biomethane.

However, an issue that would need to be addressed is the use of some transmission pipes for diurnal storage which would not but suitable for blended hydrogen. The Future Grid programme by National Grid is developing the research to support safe blending into the transmission network, and this will likely form a consideration of the research. This may also provide some operational controls to avoid the possibility of issues for distribution network injection being affected by hydrogen blending in the transmission system. There would also be benefits to the way metering is managed on the transmission network allowing for more accurate billing based on individual gas quality or GSMR.

Although it appears the decision on transmission blending sits slightly outside this consultation, we welcome the inclusion to allow for the discussion, as broadly this would be welcomed by our members. The concern would be to delay the overall decision on blending while the discussion for transmission injection is made. We would encourage a decision to be made on both as soon as possible.

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.

REA supports the strategy for blending of low carbon hydrogen as this will provide a transitional bridge while a network is adequately set up in this emerging market. It will provide the financial security for business that may initially struggle geographically for off takers. Similarly, where a producer would be reliant on a single off taker, this would also allow producers some relief where making sure everything is coordinated to have a route to market in time may be difficult and therefore offer some vital de-risking. It will therefore play a crucial role to support the scale up of the low carbon hydrogen sector at the early stages of the hydrogen economy. Particularly where electrolytic projects may have a more variable production volume than other production such as from natural gas. It can also provide the role of 'reserve offtake' where there's a disruption in demand through changes in economic activity from demand sources. Therefore, it would mitigate risk for all hydrogen production technologies but specifically low carbon hydrogen.

Similarly, the strategy sets the potential value for blending as not only the reserve off taker but as a strategic enabler. This would allow the initial hydrogen projects particularly under HAR1 and 2 a buffer and also help develop hydrogen to power routes for grid balancing to avoid curtailment. It will also allow the relevant storage and delivery infrastructure the time to develop. Storage at present is limited in scale beyond the geological options of salt caverns and depleted gas fields as although tanks are possible, they are currently limited in scalability. This limits the initial geographical options for production but are compounded by costs and regulation.

Similarly, there will be problem when moving green hydrogen by road and therefore use of the existing gas grid will be preferred with the transmission injection having significantly more advantages than the distribution grid (seasonal capacity issues, general capacity, sterilisation, CV related issues etc). Therefore, a decision on transmission blending will be needed to meet the ambitions of scaled up production. There is also a potential issue with the introduction of the EU Decarbonised Gas Package and implications of the need for possible un-blending if the decision is not at least aligned.

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.

If blending is enabled and commercially supported by government, the most appropriate mechanism currently available would be the hydrogen production business model. Although the alignment within this model may not completely lend itself to blending, it is the most appropriate and would keep hydrogen production under a consistent model. It may become apparent that there is a need to set a specific model to cover blending, to ensure flexibilities to make the suggestions identified within the responses for this consultation, however this should not be the reason to create a delay in the blending decision.

The concern remains on the decision not to allow the use of hydrogen certificates where blending has taken place. Although the REA understand that the preferable hydrogen pathway would be from producer to direct off take, the dots may not align at least for a period of time, and this will restrict the ability to move hydrogen production from 1GW in 2025 to 10GW by 2030. Although there is a need to ensure that 'quality' hydrogen is being produced and caution should be made to ensure due diligence checking being maintained, the gas grid may only be needed by some producers on an occasional and/or initial period of time. This allows the flexibilities and assurance to investors by reducing risks. The 'blend' will still be contributing to the decarbonising target and there is still value accordingly, such as with biomethane injection. There could be some additional or proportionality limits set such as with a materiality threshold. to encourage blending as a temporary assistance rather than competing with seeking off take contracts where the most benefit could be. There will also need to be consideration of the costs of associated injection infrastructure if the grid is to remain as a reserve off taker as this differs from biomethane. Some suggestions made in the REA discussion paper on financial support suggested the materiality threshold of e.g., 30% would provide the support but limit potential long term investments being made solely on blending provided this wasn't too commercially restrictive. This could also be a flat proportion applied equally or a tracker threshold based on underlying market factors.

It was also suggested in an REA discussion paper on financial support for blending published last year, that eventually the move to a mechanism that would follow the Green Gas Support Scheme may provide a route for remuneration although this is best kept under the HBM given timescales and maybe reviewed at a later date.

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.

The REA supports the options identified in the consultation and agree the hybrid approach to allowing both networks and shippers to buy blended hydrogen would allow a more balanced approach. There would be some benefit to allow networks to consume blended hydrogen to meet their shrinkage requirements whilst also allowing the shippers to trade hydrogen to meet their methane energy balancing needs.

However, we recognise that there might be some disparity with how the biomethane model works as currently this exists for shippers only and as such this is a system that's already working. However, there is no perceived 'tension' that should exist between these two purchasing options. Incentives could be used to encourage the preferential purchase of low carbon hydrogen rather than methane for particularly 'shrinkage' thus providing stimulation. This also recognises that networks will have to provide a role in flow management for CV constraints, limiting or curtailing hydrogen flows.

6. Given blending's proposed strategic role as a reserve off taker, 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.

REA supports the government approach to encourage the ability for production to be co-located to end users, where possible and within hydrogen clusters is a perfect example of the whole systems approach. However, there is a need to build production to meet the 10GW of hydrogen by 2030. The approach, although well intended to provide some assurances for long term goals, may be counterproductive.

A secondary hydrogen certifications market could help with the government's aim to provide value for money, as this could enable a move away from subsidies. The example in this would be through the biomethane market where the certificates are built into business modelling, especially where they are not tied into the consumption of specific units of energy. This can also add an additional benefit in meeting the UK emissions Trading Scheme (ETS) whilst also allowing flexibilities for industries geographically struggling to meet decarbonisation targets. Therefore, this is considered a missed opportunity and would encourage this to be reviewed. The full benefit of de-risking will only be unlocked if low carbon hydrogen is sufficiently renumerated.

It was also suggested in an REA discussion paper on financial support for blending published last year, that eventually the move to a mechanism that would follow the Green Gas Support Scheme may provide a route for certification and remuneration.

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.

Yes, we agree with the lead option to adopt a free market approach. The networks would allow injection, with injection points increasing as production ramps up. This would be based on demand but should be managed to ensure the system wouldn't be affected from sterilisation, using some agreed methodology. This approach should be optimised to ensure the system was fair and allow the market to dictate where to inject.

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.

As a trade association the REA would not have a specific project and therefore are not in a position to answer this 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.

Utilising a methodology for billing that is currently known and in place, will be preferable to trying to provide an alternative which would take significant time to and work to investigate. Therefore, we agree with the lead option to adopt Option A to work within existing frameworks from the Future Billing Methodology Report. This is based on the need to make a decision without delay as it should be recognised that biomethane projects currently run under this system and this does have a knock on to making the costs for injection into the distribution network expensive and the highest in Europe. Some of our members have proposed amendments to the detailed rules which are reported to be 'not fit for purpose' so have called for a major reform at a later date.

It was also suggested in an REA paper last year that eventually the move to a mechanism that would follow the Green Gas Support Scheme may provide a route.

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

The consultation document and specifically for this question, the economic analysis, has been well documented, carefully considered and easy to follow. We have no further comments for specific feedback other than points previously raised about how the mechanism might work to advantages.