REA Response:
BEIS Low Carbon Hydrogen Standard Consultation

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the above call for evidence. The REA represents industry stakeholders from across the whole bioenergy sector and includes dedicated member forums focused on green gas, biomass heat, biomass power, renewable transport fuels and energy from waste (including advanced conversion technologies). Our members include generators, project developers, fuel and power 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.

General comments

The REA is highly supportive of the Government commitment to develop a standard and the associated methodology for carbon accounting of hydrogen production and supply chains that can underpin investment in low carbon hydrogen.

In our view, the standard will need to be sufficiently robust to only encourage the development of hydrogen production and distribution pathways that can genuinely deliver low or zero carbon emissions. We also firmly believe that the level of GHG emissions allowed will need to decline over time to be aligned with the Government trajectory to meet its Net Zero Target by 2050. We acknowledge that the standard needs to be set at a level above zero initially, however this threshold cannot be kept flat over time up to 2050, as doing this will undermine efforts to achieve our Net Zero targets.

Q1. Do you agree that the standard should focus on UK production pathways and end uses whilst supporting future export/imports opportunities? Yes/no. Please expand on your response.

Yes. The initial focus should be on UK domestic production to support the emergence of a UK low carbon hydrogen sector in the early 2020s and minimise any delays.

However, given that hydrogen will be an internationally traded commodity, international consistency is seen by our members as crucial to minimise barriers to trade and business operations across borders. It is therefore paramount that the UK standard is suitably aligned with any other standards that have been or are being developed in the EU and beyond, whilst encouraging domestic hydrogen production. Even if this is not possible right from the start, it is essential that work to align the UK standards with other European standards starts immediately, so that international consistency can be achieved as soon as possible and is already in place when the UK is in a position to export low carbon hydrogen to other countries.

In particular, concerns have been raised by members around the potential for 'lower quality' hydrogen (ie with higher GHG emissions) being imported into the UK and sold to the UK market at a cheaper price, outcompeting domestic supplies. Equally, whilst it is important for the UK to support local production of low carbon hydrogen, the standard should not place a barrier to the import from other countries of Europe into the UK of 'high quality' hydrogen (with low GHG emissions). Page 19 of the 2020 EU Hydrogen Strategy has some useful comments about how H_2 is being promoted in many countries around the world – ie the international market is emerging.

By way of example and background, some other standards and GHG methodologies to be considered are listed below:

- The EU Delegated Regulation's criteria for sustainable hydrogen define a minimum required life cycle greenhouse gas (GHG) emissions savings of 73.4% for hydrogen (resulting in $3tCO_2eq/tH_2$) relative to a fossil fuel comparator of 94g CO_2e/MJ.
- The Renewable Energy Directive II introduces a 70% GHG saving threshold for Renewable Fuels of Non-Biological Origin (RFNBOs), although it is still unclear whether the EU will use the same fossil fuel comparator for RFNBOs as conventional renewable fuels (ie 94 gCO_2e/MJ)
- In its recent consultation on the revision of the Renewable Transport Fuel Obligation the DfT have proposed to change the GHG saving threshold for RFNBOs from 60% to 65% against the fossil fuel comparator of 94g CO_2e/MJ. This means that the maximum carbon intensity permitted changes slightly from 33.5 g CO_2e/MJ to 32.9 gCO_2e/MJ, for use of RFNBO hydrogen in transport.
- In terms of methodologies to calculate GHG emissions, the Delegated Regulation also requires that the GHG emissions savings are calculated using the methodology of the international standard ISO 14067:2018 or ISO 14064-1:2018.

We also understand that the European Commission is planning to adopt two Delegated Regulations under RED II and establish:

1. a methodology to assess GHG emissions savings from renewable liquid and gaseous transport fuels of non-biological origin (which include green hydrogen); and
2. a methodology with detailed rules on how electricity obtained from direct connection to an installation generating renewable electricity may be fully counted as renewable electricity where it is used for the production of "renewable liquid and gaseous transport fuels of non-biological origin" (which includes hydrogen) and on how electricity that has been taken from the grid may be counted for this purpose ("additionality requirements"). Under the revised Renewable Transport Fuel Obligation DfT is also establishing rules on additionality requirements and how the electricity used for RFNBO hydrogen should be counted under the Obligation.

In conclusion, consideration needs to be given as a minimum to the above standards and methodologies when developing the UK standard, as well as any other relevant international standards, to ensure these are broadly aligned, there is no significant barrier to international trade across countries and that UK domestic supplies are not placed at any disadvantage.

Q2. Would there be benefits in developing the standard into a certification scheme? Yes/no. Please provide detail.

Yes.

As explained later in the response, combined with self-reporting, a third-party verification process would ensure there is an independent assessment that the relevant hydrogen production and distribution pathway meets the relevant standard. This would improve confidence in the standard and underpin its credibility.

However, some members of the REA have highlighted that it is critical that BEIS does not 'reinvent the wheel' and develop a new certification scheme. Currently established schemes or processes (e.g. those adopted under the RTFO) could be adapted and used for this scope.

Finally, it is essential that any third-party certification scheme or verification process does not result in excessive and disproportionate burdens on the producer.

Q3. a. Is international consistency important, or should the UK seek to develop a low carbon hydrogen standard primarily based on the UK context and criteria set out above? Please provide detail.

Yes, as detailed above, international consistency is essential given that hydrogen is going to be an internationally traded commodity. The UK standard should be broadly aligned to any other standards applied in Europe and elsewhere as soon as this is practically possible, although, as highlighted above, we wouldn't want this process to delay the implementation of a UK low carbon standard. Alignment with the EU standard should be priority as that is where most UK businesses will most likely be doing international business on hydrogen with.

b. If elements of a UK standard differ to comparable international standards or definitions, would this impact the ability to facilitate investment in the UK or cause issues for business operations across borders? Yes/no/unclear at this stage. Please provide detail.

Yes, as explained above, major discrepancies in the standard may result in cheaper, low-quality hydrogen being imported into the UK and outcompete domestic supplies. Such imports of poor quality hydrogen would also work against the UK achieving its Net Zero goal.

While the above should be the primary concern, similarly we do not want to place a barrier on the import into the UK of high-quality hydrogen that can help meet UK demand once the market is more established, should there be market demand and available supply.

c. If answering yes to 3b, what elements of existing low carbon hydrogen standards or definitions are most important to ensure international consistency?

The GHG emissions threshold, the boundary of the system and the methodology to calculate GHG emissions must be broadly aligned.

Other elements mentioned by members are:

- Scope of analysis (Scope 1-3), point of production vs point of use

- Specification of hydrogen (pressure, composition)
- GWP factors applied.

Q4. a. Should the standard specify a list of hydrogen production pathways, which would be updated periodically or on request? Yes/no.

Yes, a defined list of pathways with default emission values that can be used for the calculations would certainly be useful.

However, it is important that there is flexibility within the standard to use actual values for any production pathway that is not specified in the list, and as an alternative option for any pathway included in the list. In other words, the standard needs not to be restricted to the specific list and must provide the tools for producers of low carbon hydrogen to calculate actual GHG emissions for any included or additional pathways.

BEIS must clearly state how often the list of pathways is reviewed. We would suggest as a minimum every two years.

b. If yes, we would welcome respondents' views on what production methods could have significant potential in the UK in the near term. c. If no, we would welcome respondents' views on alternative options.

The following pathways should be included, but please note there may be additional pathways that have not been included in this response:

Electrolytic (green) hydrogen – all potential configurations should be included.

- Several electrolytic projects are currently being planned and developed in the UK by several developers and consortiums. Electrolysis is suited to rapid deployment and replication.
- Although all possible configurations should be included in a potential list of pathways, the green hydrogen pathways that are seen as having the greatest potential in the UK are grid-connected electrolysers placed at the point of demand (ie remotely connected to the source/s of renewable energy). For this pathway it may be difficult to set default values as the carbon intensity of the grid varies significantly across space and time. However, this could be set as long as there is flexibility for developers to report actual values as an alternative option to better reflect the carbon intensity of the electricity used. The potential for electrolysers co-located with the source/s of renewable electricity is seen as more limited, though possible, as it is often difficult to achieve to develop and obtain planning permission for a renewable electricity generator at the places with the greatest demand for hydrogen (e.g. refuelling stations).
- The [Net Zero Strategy] recently released by Government pledges up to £100 million to award contracts of up to 250MW of electrolytic hydrogen production capacity in 2023 with further allocation in 2024.

Biohydrogen from thermal gasification of biomass with and without CCS

- An example of this pathway is the demonstration project being commissioned by Advanced Biofuel Solutions (ABSL) in Swindon using the RadGas technology. Another much larger commercial plant is being developed by the same company with

Progressive Energy at the Protos Energy Park in Cheshire, aiming at producing 350 GWh/year of BioSNG and hydrogen from 133,000 tonnes per annum of refuse derived fuel (RDF), using the same technology as the Swindon plant.

- These types of projects can accept a wide range of biomass including black bag wastes, refuse derived fuel, solid recovered fuel, tyre crumb, and any other dry waste feedstocks. It has been estimated that the UK has bioresource available to produce roughly 100 TWh of biohydrogen and we are aware of around six/seven companies looking into developing these types of projects in the UK. More than 2 million tonnes of RDF are exported into Europe from the UK which could instead be diverted into domestic low carbon hydrogen production.
- It is important that this pathway is included even without CCS, as this pathway can deliver significant GHG emission savings even when it is not combined with carbon capture. When combined with CCS it can deliver significant negative GHG emissions.
- As said above, one of the advantages of these projects is that they can take a wide range of wastes, which are likely to include both, biogenic and non-biogenic fractions. So, it is important that BEIS policy is not too fixated with, or places unnecessary restrictions on the minimum required biogenic proportions in the feedstock mixes. So long as the feedstock used doesn't distort the waste hierarchy then this sort of mixed feedstock should be encouraged.

Hydrogen from the non-renewable (fossil) fraction of waste streams

- The REDII defines 'recycled carbon fuels' (RCFs) as liquid and gaseous fuels (such as hydrogen) that are either produced from liquid or solid waste streams of non-renewable origin or from waste processing gas and exhaust gas of non-renewable origin. This includes fuels derived from non-renewable waste streams e.g. fossil waste (plastic, rubber, gaseous wastes etc.) by means of thermochemical conversion technologies such as e.g., gasification, pyrolysis and liquefaction. Such fuels, although derived from waste fossil carbon, are included in RED II because of their potential contribution to the reduction of greenhouse gases (GHG) and they should be considered by BEIS for the same reason. However, the Commission has not finalised yet the methodology to calculate the associated GHG emissions. Similarly, the Dft included proposals related to supporting RCFs in their consultation on the RTFO earlier this year but they haven't finalised the details as yet and are likely to consult on it again soon.
- It should be noted that in some cases inputs to these plants will include both, a biogenic, renewable fraction and a non-renewable fraction. See our point above about the need for the policy not to be too fixated with the biogenic fractions of the feedstock mixes.
- The pathway described below as 'Hydrogen from the non-recyclable fraction of plastic wastes' is an example of 'RCFs.

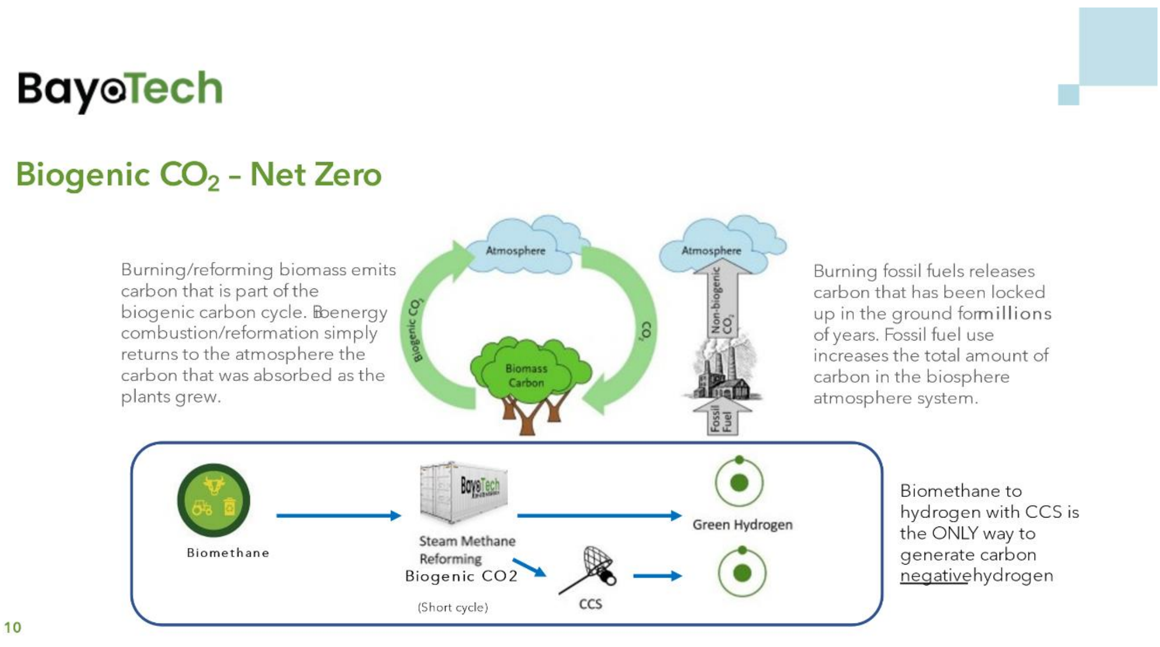
Hydrogen from the non-recyclable fraction of plastic wastes

- An example of this pathway is the waste plastic to hydrogen facility already being developed at the 'Plastic Park' at Protos Cheshire. This is being developed by Peel

NRE using technology from Powerhouse Energy Group. A second plant is being planned in Glasgow. Peel NRE has a collaboration agreement with Powerhouse Energy Group to develop 11 waste plastic to hydrogen facilities across the UK over the next few years, with the option of exclusive rights to develop a portfolio of in excess of-70 facilities. The potential is therefore significant through a replicable distributed model and can be delivered in the near term.

Biohydrogen produced from distributed steam methane reformation of biogas/biomethane from AD plants, with and without CCS

- Small scale, modular units (e.g. those developed and supplied by BayoTech) can be used to convert biogas or biomethane to biohydrogen at an AD plant, or can tap into existing gas pipelines and generate biohydrogen from gas matched to green gas certificates at the point of demand. This enables decentralised production of hydrogen locally and distribution to nearby consumers in efficient high-pressure transport trailers. In the future, when parts of the gas network are replaced with 100% hydrogen pipelines, this solution may be key to minimise the risk of some AD assets becoming stranded. As a nation we are becoming more conscious of waste re-use and avoiding methane produced by biogenic breakdown therefore feedstocks are set to become more distributed and available. These systems can be deployed today delivering low carbon hydrogen to the market at speed. Once CCUS becomes more mature and cost competitive, it can be added to these systems producing a carbon negative hydrogen stream without impacting the supply or availability of the existing hydrogen production.



Blue hydrogen with autothermal reforming (ATR) - We only support a transitional role for blue hydrogen, where the carbon is captured and stored or utilised in an application where the carbon is permanently sequestered

- A number of large-scale blue hydrogen projects are already being developed in the UK, within the key industrial clusters (e.g. Teesside, Zero Carbon Humber, HyNet, Acorn and Cavendish). Our understanding is that all these projects are setting a high bar with >95% CO2 removal from the process being considered a minimum.
- The REA's position on blue hydrogen is that this pathway is an option in the transition towards a net zero carbon economy. We only support a transitional role for blue hydrogen, where the carbon is captured and stored or utilised in an application where the carbon is permanently sequestered.
- To be compatible with net zero, blue hydrogen should achieve high CO_2 capture rates — well above 90% — and very low fugitive [methane] emissions rates. The standard method of grey hydrogen production from natural gas — steam methane reforming (SMR) — can only capture 90% of CO2 emissions. On the other hand, we understand the autothermal reforming (ATR) process, which requires the addition of pure oxygen, can capture up to 98%.
- Please see this recently published paper, which provides a balanced perspective on the impacts on climate change associated with blue hydrogen.

Other innovative pathways

Some members of the REA are also looking at is gasification of heavy refinery products (fuel oil) which would produce ash as a by-product. The ash would contain carbon, and that carbon should be included in the carbon captured for the purposes of GHG calculations, i.e. [CO_2 captured] = [CO_2 to storage] + [C in Ash]).

Q5. a. Do you agree that the standard should adopt one label of 'low carbon' hydrogen, or would it be valuable to have multiple categories? b. If multiple categories, what benefits would we get from adopting this approach in terms of emissions reduction and consumer confidence?

We have responded to Q5a and Q5b together. We haven't achieved our members' consensus on this answer, but there is a strong general appetite for incentives or mechanisms that encourage greater carbon savings beyond the minimum required level, without adding excessive complexity.

Multiple categories in the standard

Several members have said they would support multiple categories to be adopted according to the level of GHG emission savings achieved. They believe that hydrogen delivering higher GHG emission savings than the minimum threshold should be given a different label and receive a higher level of financial support. The benefit of providing different categories with different levels of support would be that this approach would clearly encourage investment in technologies and pathways that can deliver better carbon savings, whilst also supporting innovation and best practice. Certain pathways, such as electrolytic hydrogen from onsite renewables and biohydrogen from biomass gasification with CCS/CCUS can deliver zero or negative GHG emissions and can therefore go beyond the proposed minimum GHG emission threshold. This approach would provide transparency to consumers as to the energy source and the GHG emissions associated with the hydrogen being used.

One single value in the standard, with other incentives to encourage greater GHG savings

A simpler approach would be if the standard itself, which sets the minimum required level for hydrogen to be acceptable and eligible under Government support, is a single value but specific incentives are then designed on the top of that to encourage greater savings and/or particular pathways. Options for this approach would include:

1. Differentiating support levels by pathway/feedstock - we do not support this approach as different pathways can still be wide ranging in terms of GHG emissions depending on several factors, so it would be extremely challenging to determine which pathways should or shouldn't receive higher levels of incentives.
2. Giving a premium for hydrogen that achieves a specified level of savings higher than the basic standard.
3. Giving rewards/credits in proportion to levels of GHG savings achieved rather than volumes/masses of hydrogen produced.

Given that BEIS is planning to develop a methodology to measure GHG emissions of hydrogen production, options 2 and 3 above would be our preferred approach if this route was taken. We do not support option 1 for the reasons highlighted above.

One single label

Finally, other members believe a 'multiple labels' approach would add significant complexity – both to the standard and the structure of the hydrogen business model (e.g. there would need to be different strike prices for different categories/labels) - and for this reason they strongly support one single label to be adopted, at least initially, as proposed by BEIS. The 'multiple labels' approach would also require the methodology for determining the GHG emissions of different pathways to be extremely accurate if this would be the basis for determining different levels of financial support.

These members have said that if multiple labels are used, these must be allocated according to the carbon savings achieved as opposed to on the basis of the specific technology or pathway, in line with our comments above.

There may be other ways to drive growth in the hydrogen production pathways that can deliver the greatest GHG emissions savings. For example, Guarantees of Origin (GoO) should be considered by Government as these can play an important role in providing transparency to consumers on the origin of the hydrogen supplied and associated GHG savings and create a market pull for the forms/types of hydrogen pathways that deliver the highest carbon savings. GoO can be used over time to differentiate between hydrogen technologies, to generate premiums and therefore drive markets for low carbon hydrogen with the lowest carbon emissions.

Currently there are registries that issue GoO for biomethane injection in the UK. The biggest such scheme is the Green Gas Certification Scheme (GGCS) which is operated by the REA's subsidiary Renewable Energy Assurance Limited (REAL). The GGCS has been operating successfully since 2011 and is a robust and trusted scheme. The scheme is planning to design and run a pilot for UK H_2 GoO during 2021-22 and would be happy to share its results with BEIS. The GGCS latest annual report can be read here.

We would also recommend that BEIS consider the recommendations set out in the National Grid's Hydrogen Gas Market Plan. In particular, Work Package 3 includes an insight piece on Hydrogen Guarantees of Origin and the role these could play in the pathway to 2050. The final report for this package is due to be published soon.

Finally, it should also be noted that BEIS is also planning to develop policy to support Greenhouse Gas Removal technologies (GGRs), including Bioenergy with Carbon Capture and Storage, as these are seen as essential to meet net zero. The Government has recently published their response to the Call for Evidence on GGRs issued earlier this year. BEIS is planning to consult on their preferred business models to incentivise early investment in GGRs in 2022 and also to explore the role of the UK ETS as a potential long-term market for GGRs.

So, any decision taken by BEIS with regard to supporting hydrogen that delivers negative GHG savings should take into account BEIS future plans on GGRs.

Q6. a. Do you agree that a UK low carbon hydrogen standard should be set at the 'point of production'? Yes/no.

No. The majority of members don't agree with setting the standard's boundaries at the 'point of production'.

Some members, however, believe that inclusion of downstream emissions would add significant complexity for large plants with multiple and often changing users and support the standards' boundary at the point of production.

b. If no, what would the advantages be of the standard making assessments at 'point of use' or 'point of use + in use emissions'?

Downstream emissions

Given that hydrogen could be produced at one point and moved elsewhere, the GHG calculation should include emissions associated with further processing energy (ie compressing) and transport to its place of use. GHG emissions for hydrogen distribution from the point of production to its point of use can vary substantially, depending on the route taken, and these differences should not be ignored. Purification, compression, distribution and leakage in the supply chain could increase the GHG intensity of the hydrogen supplied and need to be considered.

We don't believe this calculation should place an unreasonable burden on hydrogen producers and inclusion of downstream emissions is also in line with the approach taken under other energy policies (e.g. RED, RTFO and RHI[1]).

Under the RTFO, for example, the certificate is awarded at the point at which the fuel crosses the duty point (ie it is committed to being a transport fuel rather than something else). For liquid fuels that will be either the refinery where it is blended into fossil fuel or the point at which it is imported to the UK as a finished fuel. So, there may be some further transport emissions after that point to get it to the place of use, but these will be relatively minor – and in any case, the same transport movements would have occurred had the fuel been 100% fossil.

[1] Though losses in the gas network (shrinkage) are not counted for biomethane in the RHI.

In the case of biomethane used as a transport fuel, the duty point is the point at which the filling station takes the gas out of the network – so there will be next to no further emissions before it is put into the vehicle (assuming fugitive emissions from putting fuel into the vehicle are negligible).

Downstream emissions matter even more where the fuel is moved by road and intended to be used as a transport fuel. Given the relatively low energy density of hydrogen compared to diesel or petrol, those emissions could be significant.

That is because hydrogen is far less energy dense than petrol or diesel and far fewer journeys from a tanker of hydrogen than you do from the liquid fuels it replaces. Those additional road movements need to be taken into account (to give an idea of scale, if you're running HGVs on hydrogen you would get fuel for 5-6 HGVs from a single tanker movement. The equivalent HGV running on diesel (or biodiesel) would get you 20-25 HGVs full). If hydrogen is injected into the gas grid, then there should be consistency of treatment between methane and hydrogen.

If the Government financial support goes to the producer, then there will need to be a robust way of tracking/calculating the additional emissions involved in a way that does not create a disproportionate burden. For example, in the event of a mature market for hydrogen developing, there may in time be opportunities to sell hydrogen to aggregators without the original producer having visibility or control over the final use. Inclusion of downstream distribution emissions would also eliminate the issue associated with including a reference level for purity and pressure, as any emissions associated with the processing required to reach the end user required purity and pressure levels would need to be counted for.

<u>'In use' emissions</u>

Some members agree with BEIS that these emissions should not be included in line with other energy policies. RED, for example, don't measure GHG emissions from the actual use of the fuel (e.g. from burning it at the appliance level). According to these policies, if the fuel being burned is biogenic, then the CO_2 released at combustion is not increasing net atmospheric CO_2.

UK heat and power policies burning biomass don't count combustion emissions, but they do apply a conversion factor when calculating GHG savings. So, a device burning material with 90% efficiency has half the GHG emissions of one burning the same material with 45% efficiency.

There are two good reasons for taking this approach in heat and power sector, but this may not apply to hydrogen combustion:

- There is a significant difference in efficiency levels achieved, so the policies want to push individuals and companies to maximise resource efficiencies.
- To better reflect a preference for using biomass for heat rather than electricity generation.

Some members, however, believe that ‘in use’ emissions should also be included, because different uses of hydrogen and different types of hydrogen being used could have a different impact.

For example, some members mentioned that using 100TWh of H_2 for combustion may have a different impact from using 100TWh of H_2 in the transport sector via FCEV in terms of NOx emissions.

We are aware that the Hydrogen Strategy states on page 82 that “we will support industry to work with the Environment Agency and other regulators to reduce the creation of nitrogen oxide (NOx) emissions that the combustion of hydrogen in an engine or boiler creates, helping to deliver on our air quality targets to deliver cleaner air for all.”

Also, if the hydrogen is not pure (e.g. 90% hydrogen), there will be emissions associated with the contaminants present within the gas) when it is burned at the appliance level.

Furthermore, some members highlighted that green hydrogen production liberates oxygen (which replenishes the atmospheric oxygen that is consumed when hydrogen is utilised) unlike other types of hydrogen. Oxygen depletion is a global problem that is also contributing to global warming, which government should not overlook (see further information here).

Q7. Which chain of custody system would be most appropriate for a UK low carbon hydrogen standard: a mass balance or a book and claim system? Please explain the benefits of your chosen option.

There are differing views from our members on this topic, summarised below. However, the majority of members support a Mass Balance approach, as it is reliable, traceable and comprehensive.

Some members have argued that Book and Claims should be the preferred route for the UK market, as it is simpler. If we are going to see a mass market growth for hydrogen over time, then the Book and Claims approach is by far the most pragmatic approach to adopt.

However, other members have commented that with a Book and Claim system combined with the system boundary at the point of production, it will be far easier for imported ‘lower quality’ and potentially cheaper hydrogen to reach the UK market and outcompete domestic production. So, from a UK producer’s perspective, a mass balance approach with the system boundary set at the point of use would be the preferred option to ensure the GHG impact of distribution is properly taken into account.

Finally, mass balance is the approach adopted in other energy policies (including RED and the RTFO) and it is likely that any EU standard being developed for low carbon hydrogen will be based on a mass balance system, so the mass balance approach would also be good to ensure international harmony. We note that the E4Tech report states “if the system boundary was set at the point of import to the UK, with a book and claim approach, then a default factor would need to be added for transport emissions, which may be difficult to define fairly given the range of possible values for different distances and transport options".

Some members highlighted that Book and Claim could also be potential used to allow grey hydrogen to be used in the UK, supported by the production of green hydrogen elsewhere in the world.

Whatever system is chosen, it important that it provides suppliers sufficient information that they can then provide to their customers on the type of gas product they are using.

Q8. Should other CoC options be considered instead? Yes/no. If yes, please provide detail.

A "book and claim plus" system could be considered. In this system some elements of a mass balance system are introduced whilst maintaining some of the flexibility of a book and claim CoC. For example:

Physical traceability – the UK could be defined as "system boundary" for production and consumption without requiring a physical connection e.g. a pipeline.

Temporal relationship – an annual balancing period between production and consumption could be chosen, in contrast to 3 months in existing mass balancing and unlimited timing in some book and claim systems.

In this way some criticisms of book and claim system could be addressed without imposing the full burden of a mass balance CoC.

Regardless of the CoC method chosen there must be a robust and recognised electronic registry for the issuing of Certificates.

Q9. a. If the system boundary was set at the point of production, should there be defined reference purity and pressure levels for a UK low carbon hydrogen standard? Yes/no.

Yes.

b. If yes, what should they be?

For the reasons highlighted above, the system boundary should be set at the point of use to take into account emissions associated with downstream distribution. This would avoid the issue of having to include reference purity and pressure levels, though under this scenario BEIS may need to consider setting separate thresholds for different uses. This is because different end users have different requirements in terms of purity and pressure and there are significant differences in the GHG emissions associated with processing hydrogen for different end users' specifications. Hydrogen processing for use in heating, for example, may be far less energy intensive than for use in transport (this is not the case for electrolytic hydrogen, which in purity terms would meet both specifications with no need for further processing).

If ultimately BEIS decides to set the system boundary at the point of production, then we would recommend that reference purity and pressure levels <u>are</u> included so that there isn't a perverse incentive to produce hydrogen of lower quality in order to become eligible for financial support from Government, with the burden then placed on someone else to carry out the additional, energy intensive processing required to meet the end user specification.

A member suggested that the pressure reference value should be whatever is expected for the purpose of transporting hydrogen by road. Unless the production facility is connected to a grid that connects directly with end users (whether a dedicated hydrogen one or the existing gas grid) or is used on site, then the gas will definitely be transported by road. There is clearly an energy demand (ie electricity) to compress the gas onto the truck, but it should also be considered whether there is likely to be an energy (heat) demand when taking the gas off the truck and reverting to whatever pressure it is intended to be used at.

Another member of the REA suggested that the pressure level should be the value suited to the suction side of a compressor with a view to minimising the compression energy overhead (e.g. no less than 10 bar and preferably 20 bar), because many applications require hydrogen compression or the feeding of hydrogen into a pipeline network at elevated pressure.

c. If no, what are the benefits to not defining reference purity and pressure levels?

See answer above

Q10. a. Should there be minimum pressure and purity requirements for hydrogen to meet the standard? Yes/no

Yes

Some members commented that if lower-purity hydrogen is allowed, and the balance is carbonaceous species, only the energy content associated with hydrogen should be rewarded.

b. What could the potential implications of setting minimum purity and pressure requirements be?

It would improve confidence that the hydrogen produced is suited to the relevant end use.

Q11. a. Do you agree that embodied emissions should be omitted from the calculation of GHG emissions under a low carbon hydrogen standard, to ensure comparability with global and UK schemes? Yes/no.

No.

b. If no, what are the benefits to including embodied emissions in the calculation of GHG emissions, and what should be done to ensure that hydrogen is on a level playing field to other energy vectors?

There are differing views from our members on this topic, summarised below.

Some members of the REA believe that embodied emissions should be included given that in some cases, for certain supply chains (e.g. UK Solar PV systems) embodied emissions could be significant and therefore cannot be ignored. For example, this recently published report, which includes a Life Cycle Assessment of different Hydrogen Pathways, states that: '*Solar power achieves 1.0 kg CO_2eq/kg H_2 and wind 0.5 kg CO_2eq/kg H_2 in 2030, the difference resulting from the higher embedded capex emissions for solar panels (due to global grid mix assumed for the panel manufacture)'.*

These members have also said that a materiality test should be included so that production pathways with immaterial construction emissions do not have to include them.

Other members, however, believe embodied emissions should not be included, as this is in line with other policies (e.g. RED II, which excludes embodied emissions from construction) to ensure consistency across different policies and not to create advantages or send messages to the market that favour the use of certain technologies / production pathways in certain markets. Inconsistency across policy in the way embodied emissions are accounted may create barriers to market and this should be avoided.

Another consideration for not including them is that there is not much a developer/installer of a given technology can do to change them. They are a relevant consideration for policy at a macro level. When looking at the overall benefits of wind or solar PV, policy makers should look at these factors as well as potentially other areas around broader sustainability of the supply chain producing them.

When looking at industrial emissions from manufacturing and construction then it would make sense to count these emissions, in the same way that you'd be looking at the carbon intensity of your concrete.

Q12. a. Do you agree that a UK low carbon hydrogen standard should include the global warming potential of hydrogen? Yes/no. b. If no, are there other options for accounting for the GWP of hydrogen outside of a UK low carbon hydrogen standard that could support compatibility with existing standards/schemes?

Yes.

A GWP should be included to allow fugitive losses to be calculated.

Assuming it is a material thing then should definitely be included, as it would encourage producers to reduce their emissions.

Global policies are about to aim for far greater production of hydrogen than has been the case up to now. Given the significant potential of this sector to grow, then this will encourage developers to make the right design/engineering decisions from day 1.

Q13. a. Should a materiality threshold for total emissions be included in the life cycle assessments of hydrogen pathways? Yes/no.

b. If yes, what would the most appropriate level be and why?

Yes.

Other policies such as RED and RTFO use 1% as a materiality threshold and this seems reasonable. Some members have commented that 2% would also be reasonable, but

5% would be too high if we aim at further reducing GHG emissions of hydrogen over time to reach Net Zero.

Q14. a. Should CCU with proven displacement or permanence be included as an allowable benefit in GHG calculations under a UK low carbon hydrogen standard? Yes/no.

Yes, we agree with the overall principle that if displacement or permanence can be proven then sites should receive an allowable benefit as part of the hydrogen standard. However, as identified in the consultation, suitable accounting rules still need to be agreed to understand how this is demonstrated with suitable assurances provided around how long the carbon remains out of the atmosphere. As such, further analysis and consultation will be needed in order to set out an appropriate methodology before confirming the types of CCU that would benefit.

It is important that a joined-up approach is adopted across different Government departments and policies. For example, any decision made for the hydrogen standard should be aligned with Government policy on GGR, which is being developed by BEIS in parallel and any other relevant energy policies (see here for further information).

Finally, some members pointed out that BEIS needs to bear in mind any interactions with the UK Emission Trading Scheme. Over time companies will not want to use fossil carbon as this means they have to pay the UK ETS tax on it and this makes it unfeasible financially. So, obtaining a credit for fossil use will be effectively cancelled out by the tax paid under the ETS, which makes it pointless. The E4Tech report states "that there are other policies in place that will affect GHG emissions from hydrogen pathways, such as fossil emissions from production plants being covered (and therefore disincentivised) by the UK ETS, and policies to decarbonise various supply chain steps such as road transport."

b. If yes, what should a suitable minimum time be for proven permanence and which applications should be eligible?

This should be consistent with international methodologies on climate change and the IPCC may provide recommendations on a suitable time period that that can be used.

Long lasting needs to be long enough that global annual emissions have declined so far that the impact of some leakage on further climate change would be negligible. In other words, the damage that has been done to the climate has been done but we are not causing further damage.

Q15. Should CCU credits only be allowed for biogenic carbon, and not allowed for fossil carbon sources? Yes/no.

Yes, though some members disagree on this issue.

Q16. As the grid is decarbonising rapidly, so will grid connected hydrogen production pathways. How should government policy take into consideration hydrogen production pathways using grid electricity as primary input energy now? Please explain the benefits to the approach you have suggested.

General, high-level points:

- We support the principle that Government policy should not be available to all hydrogen production pathways regardless of the carbon intensity of their primary energy input, however the rules to account for such energy inputs need to be workable and pragmatic, and they should not constrain sector growth, especially in the initial years of sector development. Low carbon hydrogen is not yet cost-competitive against fossil fuel and overly-prescriptive and burdensome rules may end up hindering the market's growth, reduce the potential for quicker cost reductions and competition. The Climate Change Committee has pointed out that by 2030, significant electrolyser capacity (for hydrogen production) is being planned for in France, Germany and the Netherlands (5 GW, 6.5 GW and 3-4 GW respectively) and the European Commission new hydrogen strategy is aiming to reach 40 GW of electrolyser capacity across the EU.
- Government should recognise and focus on the strong role of electrolytic hydrogen as a key route to enable the development of additional renewables and the integration of increased shares of renewables in the energy system. This is paramount if the UK is to reduce its reliance on imported fossil gas and to stimulate growth and penetration of increased renewable electricity sources to meet demand for a number of markets (power, heat, and transport). We believe it is likely that growth in the green hydrogen sector, especially flexible electrolysers - will actively stimulate new low carbon primary energy sources and allow further penetration of renewables, as opposed to drive additional high carbon electricity generation.
- Electricity can be converted into hydrogen by electrolysis, and later used to generate electricity. The round-trip efficiency of this is currently lower than other storage technologies such as batteries, but the capacity is very much greater, opening up the potential for inter-seasonal storage of renewable energy via geological storage. In light of such longer duration, large scale energy storage is necessary if we are to successfully transition our power system to a net zero world and so hydrogen could play a very valuable role in the mix in a future energy system. In summary, hydrogen production and storage will help accommodate more renewables in the system, unlock this sector's potential and help decarbonise power, transport and heat and Government policy should focus more on this aspect.
- Given the Government commitment in the Hydrogen Strategy to a twin-track approach which support the production of 'blue' hydrogen from natural gas, consideration should be given to any source of fossil gas used for the production of blue hydrogen. The impact associated with different types of natural gas from difference sources is significantly different – for example, GHG emissions associated with producing and importing into the UK liquified natural gas from the Middle East are likely to be much greater than for natural gas from the UK Continental Shelf. BEIS recognise this in establishing the carbon factor for grid gas ie taking different emission factors for different types of natural gas used in the UK. They have the data and hence should apply it for the different sources of natural gas used when producing blue hydrogen.It is paramount that UK policy to support hydrogen does not result in an increased demand in the UK for higher carbon intensive, fossil gas. For example, this recently published report including a LCA of hydrogen pathways states: '*Sweet natural gas sources [ie free from hydrogen sulphide and therefore*

requiring less purification] in combination with high carbon capture rates and transport distances in the low thousand kilometres can reduce GHG emissions substantially: for example, in the case of SMR with a carbon capture rate of 90% and natural gas from Norway transported over a distance of 1,700 km to the German or Dutch North Sea coast, GHG emissions amount to 1.5 kg CO_2eq/kg H_2, and to 2.7 kg CO_2eq/kg H_2 in the case of an SMR with a CO_2 capture rate of 75%'. Also '*SMR without CCS with Russian natural gas transported over 5,000 km (11.0 kg CO2eq/kg H2) show the highest GHG emissions for 2030 of pathways analysed here'.*

When considering upstream emissions from gas production, however, it is important that the following is taken into account:

- Gas molecules are delivered by a common grid. It should be permitted to 'mass balance' gas source across the gas grid, so that blue hydrogen producers can contract for low-carbon gas and this can be counted for in the emissions calculation.
- Default data for different gas sources (e.g. UK Continental shelf, LNG, shale) should be provided, and these default values should be grandfathered for the lifetime of hydrogen production facilities to reassure investors.

Q17. a. What options should we consider for accounting for the use of electricity under a UK low carbon hydrogen standard? Do the options outlined seem appropriate? Are any of these particularly problematic? Please explain your reasoning. b. Of the options considered, should further conditions be included to mitigate any negative impacts or potential unintended consequences, such as driving additional high carbon power generation, and what could these conditions be?

Similar discussions have been taking place during the DfT's review of the Renewable Transport Fuel Obligation (RTFO) and lessons can certainly be learned from this policy.

Physical links

We do not support the option based on physical links, as it is highly restrictive both in terms of load factor and geographical location.

This option is also in place under the current RTFO (though it is currently under review) and has significantly constrained the development of Renewable Fuel of Non-Biological Origin ('RFNBO') hydrogen for supply in the transport sector and as it stands it is certainly a key barrier to future growth. This is because eligibility is effectively restricted to hydrogen produced from electrolysers at the point of renewable electricity production (co-located) and under specific, very restrictive conditions.

In particular, we understand from our members that the 'off-grid' option (electrolyser and renewable electricity source (RES) co-located with the electrolyser absorbing all of the electricity generation) has limited potential for growth, due to a number of reasons including:

- The capacity factor of renewables (RES) places severe constraints on the electrolysers' operating hours as these would be limited to those in which renewable electricity is being generated. Our understanding is that this would only work economically if the electrolyser can source electricity from the grid at times when RES is not generating.

- There is a significant difference in the lead-in times of some renewable electricity projects and electrolysers. Offshore wind generators, for example, would typically take much longer to develop, which creates the risk of having electrolysers ready but not the RES creating a risk for investors.

The option of <u>an electrolyser connected to an existing, but constrained</u> RES is also economically very challenging. Developing an electrolyser solely on the basis of a curtailed electricity source means the electrolyser's load factor may not be sufficient to justify the upfront capital cost of the electrolyser. In order for this model to work financially, the electrolyser would likely need to be connected to multiple sources of renewable electricity which enable the hydrogen production plant to run at a sufficient load factor (typically a load factor between 50 and 60% would be required for the financial model to work).

In addition, there doesn't appear to be clarity of what the definition is of 'curtailed' or 'constrained' and how this can be evidenced. More clarity is required on this point.

Electrolyser plugged into the grid

We support the option of <u>allowing electrolysers to plug into the grid but under certain conditions set out below.</u>

This option would only work if the grid average met the CO_2 intensity threshold for qualifying. Under the RTFO the value used for carbon intensity of the grid is the national average of the grid of two years previously. Under this policy electrolysers are currently not allowed to use the actual electricity grid intensity from the time used to produce green hydrogen. This has meant that no projects connected to the grid can in practice qualify under the RTFO.

It would be possible, however, to accurately calculate the carbon intensity of the electricity sourced from the grid: instead of using a national average from two years previously, the actual GHG emission intensity of the grid could be calculated quite precisely, because all electrolysers have half-hourly electricity meters and should therefore be able to compute running average or monthly/annual GHG intensity values for the hydrogen produced in a precise manner, given that the electricity industry publishes carbon intensity values of generation on a similarly short time basis. This carbon intensity value could be checked against the defined threshold. Hydrogen below the carbon intensity threshold would be eligible and this would in turn encourage electrolysers only to produce hydrogen at times where the electricity is below the carbon intensity threshold. Only electrolysers that operate on a base load basis should use the average carbon intensity of the grid.

This does mean the green hydrogen project has to take a risk on the grid hydrogen carbon factor going up or not falling as fast as predicted i.e. this year with low wind, GHG levels will be above 2020.

In the recent RTFO consultation, DfT sought views on whether they should permit fuel suppliers to use local grid GHG emissions factors in RFNBO GHG emission calculations (e.g. circumstances in which this might be appropriate include where there are local grid constraints or other local conditions which mean that the local grid GHG intensity differs substantially from that of the grid on a national basis). We agreed with the approach proposed as it is consistent with their broader approach to allow RFNBO production and electricity generation to take place at different sites and there are regions where electricity is already of low GHG intensity compared to others.

A member has also noted that Government should differentiate between flexible and inflexible (e.g. base load or other fixed operating mode) electrolysers connected to the grid and encourage flexible operation. Whilst operating electrolysers on the grid in an inflexible mode could increase peak demand and result in additional requirements for fossil power generation, running electrolysers in a flexible mode would assist greatly in enabling integration of renewables and should not be seen as another electrical load. To encourage electrolysers to run in a flexible way, the approach above should be combined with appropriate tariffs (e.g. interruptible/time-of-use) and/or PPAs with renewable energy generators that encourage flexibility and discourage inflexibility.

In summary, BEIS should allow electrolysers to be plugged into the grid as they can assist, rather than exacerbate, integration with renewables. Flexible electrolysers, which can turn off during times grid electricity is high carbon ie during peak times (e.g. 4 to 6 pm) or as instructed on a day ahead or week ahead basis as a function of the expected grid GHG intensity. There should be preferential electricity tariffs for electrolysers operating in this mode that are helping to balance the grid.

It should also be noted that electrolysers operating in a flexible mode may need additional storage capacity adjacent to the electrolyser and will therefore have a higher CAPEX. This should be reflected in any fund and producer-led mechanism designed by BEIS to support low carbon hydrogen.

Traded activities

We also support the option based on traded activities, or traded activities plus certain conditions (as long as these conditions are workable and not overly prescriptive), as this option gives more flexibility. It would expand the range of electrolytic projects that can be supported by Government and enable the development of hydrogen production plants at locations where it makes more sense to build them (e.g. in some cases, close to the point of demand as opposed to where the source of electricity is).

We agree that the use of PPAs combined/bundled with Guarantees of Origin for Renewable Electricity could provide a link between the generation of renewable electricity and its consumption, and this is our preferred option. However, more clarity needs to be provided on what sort of PPA would be needed and how the commercial barriers identified below can be overcome. In particular, for PPAs we raised a number of concerns in our response to the recent DfT consultation on the review of the RTFO, which we have copied below. These are largely applicable to BEIS proposals on hydrogen low carbon standard.

If necessary, we could start with the option of grid plugged electrolysers forts and move to the PPA plus GoO approach when available.

<u>Excerpts from REA Response to RTFO consultation</u>

The most common situation would be one in which the generator sells its power to a supplier (via a PPA) and the RFNBO producer [the producer of green hydrogen] buys power from that supplier (also via a PPA). How will the RFNBO producer be able to demonstrate the link between the generator and themselves? We note that the original power could be resold multiple times before it is eventually sold to the RFNBO producer.

If the intention is that the RFNBO producer will need to show the RTFO administrator the original PPA between the generator and supplier, then this is unlikely to be available given that it will contain commercially sensitive information. It would certainly not be in the RFNBO producer's power to compel this information. Moreover, if the generating site is already in operation it is likely to have its commercial arrangements in place and is unlikely to be willing to alter these to assist a prospective RFNBO producer.

Even if the documents were made available, it would not necessarily show that such generation was the electricity that was provided to the RFNBO station or that there was no double counting of the renewable electricity.

We would also note that PPAs come in many forms and may not always be straightforward around volumes and timing of export. They generally involve a commitment by the purchaser to buy all the output of a site over a given period rather than stipulating a specific amount that will be generated (or even a minimum). They may also be power-only, so that the ROCs and/or REGOs are sold separately from the power generated. In those circumstances, the power is effectively being sold as 'brown' power, allowing the renewable benefits to be sold on separately [though note that this issue would be addressed by BEIS proposal that the PPA is combined/bundled with the cancellation of Guarantees of Origin].

Given the above, we would suggest that there needs to be further consideration of how this approach would work in practice and avoid double-counting of renewable electricity.

As a minimum, this would suggest that a flexible and pragmatic approach will need to be taken on how these rules are applied.

Further, as noted in the consultation, there will be losses via the electricity grid so that the renewable energy available to the RFNBO generator will be less than that exported to the grid by the generator.

Under the RTFO policy, the requirements for additionality does not prevent the generating site having received support via the FIT, RO or CfD schemes. We think there is a good rationale for this in that the electricity support schemes drive the production of renewable electricity while the RTFO supports making a transport fuel using that electricity. [We are aware BEIS is seeking feedback under a different consultation on whether the same principle should apply under BEIS support e.g. hydrogen business model and we are providing feedback on this point via this separate consultation].

Care will need to be taken, however, in how this interaction is managed in the context of the UK's future trading arrangements with the EU. Now that the UK has left the EU, there is no mechanism for pre-approval of support schemes, meaning there is the risk that new support measures could be challenged after they have been implemented. In order to avoid disruption to the industry and investors it is essential to avoid this if at all possible.

Cancellation of REGO and potential impact on FMD

If the option of PPAs combined with Guarantees of Origin is chosen by BEIS, any potential impact on Fuel Mix Disclosure (FMD) must be considered.

All electricity suppliers in Great Britain are required to disclose to their customers the mix of fuels used to generate the electricity supplied annually. Renewable Energy Guarantees of Origin certificates (REGOs) are used to prove renewable electricity purchased for supply to customers in GB. If BEIS requires the hydrogen producer to own and cancel the REGO, this will be worthless to the energy supplier who will no longer be able to use the REGO to prove the supply of renewable electricity within the FMD. This issue must be carefully considered. The energy supplier may not make a financial loss if the hydrogen producer pays an equivalent amount of money, but if this happens regularly it may result in the energy supplier reporting a decreased proportion of supplies from renewable energy sources, which could have a detrimental effect on public perception of them – and would be a severe disadvantage to a supplier that marketed itself on the basis of supplying a high proportion or 100% renewable electricity.

It should be possible to prove that the power used by the electrolyser was awarded REGOs at the point of generation, without the need for the hydrogen producer to 'own' the REGOs. The challenge with proving this is that REGOs are not time stamped at present so the suitability of this solution depends on how strict and granular BEIS decides to be on the requirement of temporal correlation.

Temporal correlation

The rules around demonstrating temporal correlation must be workable and pragmatic and must be aligned with what can be realistically achieved under current PPAs commercially available in the market and existing Guarantees of Origin for Renewable Electricity. Once more granular information matching generation with consumption becomes available, the rules may need to be re-considered. For example, we know that industry is innovating on this topic and a number of demonstration projects are being run under the EnergyTag initiative to move towards increased temporal granularity. This initiative is aimed at defining and building a market for hourly electricity certificates that enables energy users to verify the source of their electricity and carbon emissions in real time. Further information about this initiative can be found here. The report states:

'Given the fact that CO_2 emissions from the power grid can vary from hour to hour, hourly certification of electricity (including CO_2 emission factor) is therefore crucial to allocate CO_2 emissions of renewable and low-carbon hydrogen production in a

meaningful way. Such hourly certificates will facilitate the development of future hydrogen certificates which are crucial to the development of an efficient hydrogen market.'

It would be useful for BEIS to understand what the timeframe of this initiative is and when it is expected that more granular certificates will start to be made available in the market. Until that point, however, careful consideration should be given to any requirements placed to ensure they can be implemented in practice and don't place excessive burden on producers.

Generally, Government should consider the extent to which this degree of temporal correlation is actually needed in order to align electrolytic hydrogen production with periods of 'excess' renewables. We would note that electrolysers are already exposed to price signals on low or negative pricing, which already gives them some incentive to respond accordingly to a certain extent. We would expect the strength of those signals to increase over time, while the average GHG emissions of the electricity grid will reduce.

Finally, if BEIS decides to adopt these rules, these should be as aligned as possible to those set out under the RTFO by the DfT. In the RTFO consultation DfT suggested a 30-minute time period[2] and, based on industry feedback, we think this time interval is feasible, but further clarity needs to be provided on the evidence required to verify this time interval. An excerpt from our response on this proposal can be found below, which is still very much in line with our thinking.

<u>Excerpts from REA Response to RTFO consultation</u>

In general, a 30-minute time period seems appropriate, although we would note that this may not occur in all PPAs - co-located private wire PPAs may be less likely to do so, for example.

It is unclear what the evidence requirements on the RFNBO for this will be. In order to demonstrate the correlation, would the RFNBO producer need to provide the invoicing information between the generator and the initial purchaser? If so, then this would appear to be more commercially sensitive than the underlying PPA. If this is not required, then how is the temporal correlation to be shown with this level of granularity? The generator could make a statement to that effect but it is unclear what incentive there would be for the generator to do so or what audit/enforcement powers would exist so that the RTFO administrator could confidently rely on it.

Even if these issues are addressed, it is unclear how the RFNBO producer could ensure they only took electricity from the grid at the right time unless they also had constantly-updated live information from the generating site. This would be a very high level of ongoing co-operation, even if it was in practice reasonable to operate the RFNBO plant in such a flexible way – in other words, making a decision every 30 minutes whether to continue or shut down.

[2] For background, a 30 minutes time period would also fit with upcoming move to half hourly settlement for domestic and commercial premises.

DfT should consider the extent to which this degree of temporal correlation is actually needed in order to align RFNBO production with periods of 'excess' renewables. We would note that RFNBO producers are already exposed to price signals on low or negative pricing, which already gives them some incentive to respond accordingly. We would expect the strength of those signals to increase over time, while the average GHG emissions of the electricity grid will reduce.

It would also be important to take into account the use of battery storage. Where electricity is generated at a time when the site is constrained and used later by the RFNBO plant, the relevant correlation must be when the electricity was generated rather than when it was used.

<u>Other relevant points to traded activities</u>

As mentioned above, the definition of 'curtailed' or 'constrained' electricity needs to be clarified and any evidence required to demonstrate that the electrolyser is using curtailed electricity.

It is also unclear what configurations would be allowed under traded activities. For example, whether an electrolyser remotely connected to a RES via a PPA plus GoO will need to evidence that they are only using curtailed electricity (and, if yes, what evidence will be required), or other configurations will be allowed. We hope the latter.

Finally, it is crucial that the PPA can be amended over time to include additional sources of renewable electricity. As highlighted before, the economic case for electrolysers that rely on electricity constrained off the grid is often dependent on being able to access multiple sources. These may not all be available at the same time, so it is important the PPA is not rigid but set up to allow more additional RES to be added when these become available.

Q18. What evidence should BEIS consider ahead of making decisions around the use of electricity as primary input energy for hydrogen production?

See answer above

Q19. How should low carbon electricity use in hydrogen production be accounted for in order to support the deployment of hydrogen production via electrolysis, whilst avoiding unintended consequences such as increased generation from high carbon power sources (impacting grid decarbonisation)?

See answer above

Q20. Should a UK low carbon hydrogen standard include a requirement on additionality and why? Please explain the benefits to the approach you have suggested.

High level points about additionality

The REA supports the principle of additionality: overall, we agree that any additional demand for electricity should be matched by additional generation of low carbon electricity.

However, the associated rules need to be pragmatic and workable and not limit growth of green hydrogen production, especially in the initial years.

In addition, in our view this principle needs to be considered within the wider energy policy context. It is discriminatory to scrutinise only the electricity that is used to produce electrolytic hydrogen. The principle should apply to all new electricity demand, including that required for power, electrification of heat and decarbonisation of transport (EVs). Substantial increases in electricity demand are a direct consequence of decarbonisation pathways for heat, transport and other sectors. These risks are best managed at the macroeconomic policy level rather than by individual hydrogen producers.

With the above in mind, we consider that the best option is not to place additionality requirements specifically on hydrogen, but ensure additionality is managed through other policy instruments, such as renewable electricity or carbon intensity targets for the power sector. A fund contribution could also be acceptable if focused on future projects where costs are relatively low e.g. offshore wind at strike price of £40MWh.

We strongly discourage BEIS from adopting the 'New built requirement', as this would significantly constrain the sector growth, doesn't work in practice and is discriminatory as outlined above. We would also not support the 'Pay existing levy' option, since it would also discriminate against hydrogen production.

If BEIS decides to include additionality requirements for hydrogen, then we support the suggestion made by some members that the requirements should only be triggered when the use of grid electricity for low carbon hydrogen production exceeds a defined annual limit over a certain period (e.g. X TWh/annum). It is unlikely that the limit would be exceeded in the early years of market development as many electrolysers in early applications are likely to be small and medium scale.

Q21. Should additionality considerations also apply to renewable heat and other input energy vectors such as biomethane, in the same vein as for low carbon electricity and why? Yes/no. Please explain the benefits to the approach you have suggested.

Yes, as this would provide a level playing field across technologies and energy vectors.

Q22. a. Should waste fossil feedstocks be considered with counterfactuals under a UK low carbon hydrogen standard? Yes/no. Please explain the benefits to the approach you have suggested. b. What are the potential implications of supporting the use of any particular waste streams in hydrogen production?

Yes.

We consider that waste fossil feedstocks should be considered with counterfactuals. The RTFO consultation earlier this year proposed a methodology for how this should be done, including an appropriate GHG calculation methodology to take into account likely displacement effects from use of that fossil feedstock. We understand that DfT intends to publish further information on its emerging thinking either this Autumn or early in 2022. Whatever approach is adopted should be mirrored in the hydrogen standard. As with the comments earlier, the UK approach should also be closely aligned with parallel policy development in the EU.

Q23. What is the most appropriate way to account for hydrogen produced from a facility that has mixed inputs (high and low carbon)? Please explain the benefits to the approach you have suggested.

Member feedback is that the approach should be aligned with the one used in RED.

We would support the option of averaging consignments whenever this sort of process occurs. It's overall GHG emissions savings that are important, after all. The producer should still report GHG emissions associated with each consignment, but the average GHG emission value should be checked against the benchmark.

If BEIS wishes to provide an incentive to achieve better than the minimum GHG savings, then it would make sense to make some of the rewards be proportional to the amount of savings.

Q24. What are the most appropriate units to calculate GHG emissions of low carbon hydrogen?

The unit gCO_2e/MJ LHV (Lower Heating Value) proposed by BEIS seems the most appropriate, and as explained by BEIS is in line with most existing standards and policies.

However, is worth noticing that the RHI is paid out and gas through the grid is traded on Higher Heating Value.

Q25. What allocation method should be adopted for by-product hydrogen and why?

The same approach adopted under the RHI (ie on an energy basis) could be followed but expanded so that GHG emissions for certain co-products that don't have an energy content are allocated on the basis of other criteria. Members who commented on this question would support a use system expansion (ie consider emissions saved by displacing the co-products in their market, through the best available technology).

Regardless of the option a default value should be agreed for all co-products and applied consistently.

Q26. Should the standard allow for negative emissions hydrogen to be reported? Yes/no.

Yes.

it would be useful for the standard to allow for negative emissions to be measured and reported as this is certainly possible producing hydrogen from biogenic sources if combined with carbon capture and storage.

Q27. a. Should non GHG impacts be taken into account? Yes/no. b. If yes, what criteria or factors should be taken into account and how? c. If no, please set out your rationale for your answer

No

This would add significant complexity and would not be aligned to other policies/standards.

It would be useful to undertake further research to understand whether these should be included in the future, but we feel that inclusion at this stage may delay the implementation of the standard.

In addition, wider environmental impact are already covered by existing regimes (EA permitting, BAT etc.).

While it is important that added value to the UK supply chain be considered in the round and could be considered for this standard, it could also be covered in the Business Model proposals.

Q28. Given the many potential end uses of hydrogen, and the rapid expansion of low carbon supplies required, do you agree that an absolute emissions threshold be adopted, rather than a percentage saving based on a fossil comparator? Yes/no. Please provide detail.

One positive aspect to using a percentage of savings is that it is easier to understand and because it is used in the RED is also easier to compare to other countries. However, we don't feel very strongly about this point.

Q29. Should the standard adopt a single threshold or several, and why?

See our answer to question Q5.

Q30. a. Should the GHG emissions threshold be set at a higher level in the early stages of hydrogen deployment, with a trajectory to decrease over time? Yes/no.

Yes.

It is paramount that there is a clear downward trajectory to 2050 if we are to achieve our net zero target.

Please explain the benefits to the approach you have suggested. b. If yes, should this decreasing trajectory be announced from the offset? Yes/no. Please explain the benefits to the approach you have suggested.

Yes, there should be visibility from the start on the trajectory so that developers and producers can plan accordingly.

Q31. What would be an appropriate level for a point of production emissions threshold under a UK low carbon hydrogen standard? Please set out your rationale for your answer.

The suggested threshold of 15-20g CO_2e/MJ LHV seems reasonable if the boundary is set at the point of production.

Given the complexity of potential end uses, an absolute carbon intensity value (as calculated on whole production pathway, including getting it to point of use as a minimum) would be our preferred option. Having said that, from an industry point of view it makes no real difference – a % saving relative to a given comparator is just another way of saving a maximum carbon intensity.

A member of the REA suggested that a suitable trajectory would be, for example but further consultation or stakeholder engagement will be required to test these suggested trajectories.

15 g CO_2e/MJ from 2030, 10 g CO_2e/MJ from 2030 from 2035 and 5 g CO_2e/MJ from 2040.

Another important point made by a member is that the hydrogen production plant should identify the expected life of the plant. The GHG intensity of the plant should be related to the expected average across that duration. This is because over that period of time the GHG intensity of the grid will almost certainly decrease and using an average across that period allows this to be taken into account (as opposed to use the initial year of operation as the reference point).

Q32. a. Could some net zero compliant hydrogen production pathways be disadvantaged by the introduction of an emissions threshold set at 15-20gCO_2e/MJLHV? Yes/no.

b. If yes, please explain which methods are likely to be disadvantaged and why.

Yes, hydrogen production pathways that can already deliver net zero or negative emissions immediately would likely be penalised by a higher threshold (as these would receive the same subsidy and support as plants that deliver lower GHG performances), however this issue would be addressed over time by setting a trajectory of declining thresholds which is aligned to our Net Zero Target.

In the short term it would also penalise grid connected electrolysers if the average carbon intensity of the grid is used. This can be addressed if BEIS adopt the approach identified above for grid connected electrolysers to encourage electrolysers' operation in a flexible mode via a specific electricity tariff or PPAs. Under this scenario the carbon intensity of the electricity used would be below the average carbon intensity and would likely comply with the threshold.

Q33. a. How could we ensure that a low threshold does not negatively impact projects on a trajectory to net zero and learning by doing at the early stages of hydrogen market development? b. What impact could this have on the UK achieving 5GW production capacity by 2030?

Setting a higher GHG threshold initially and a declining trajectory over time (as previously suggested, for example every five years) will enable the sector to grow in early years of market development whilst also ensuring that our Net Zero Target is met.

Q34. a. Should the UK low carbon hydrogen standard provide for some limited leeway on the threshold for existing hydrogen production facilities? Yes/no.

No.

A member commented that existing hydrogen production plants should be incentivised to implement carbon capture, even if they cannot meet the standard threshold. Others commented that any existing grey hydrogen production plants should not be allowed any leeway as they need to transition to lower carbon hydrogen as soon as possible.

However, any low carbon hydrogen plants supported by Government under Government incentives for low carbon hydrogen should be grandfathered for at least 15 years – this is in line with other forms of renewable support and will provide investor certainty.

Please explain the benefits to the approach you have suggested. b. If yes, is a 10% leeway suitable? Yes/no.

NA

Q35. What would be an appropriate level for a UK low carbon hydrogen standard if it were considering point of use emissions? Please set out your rationale for your answer.

The issue is that different markets require different specification for the hydrogen. For example, purity and pressure required for use in transport are higher than the specification required for combustion for heating. Transportation of hydrogen from the point of production to the point of use may also vary significantly. Use of hydrogen as a feedstock in manufacturing processes such as ammonia production will also different emissions.

In addition, some members highlighted that hydrogen distribution is likely to be outside the control of the hydrogen producer so there may need to be a separate standard and threshold for the distribution side.

Q36. Which type of organisation would be best placed to deliver and administer a Low Carbon Hydrogen standard? Please include examples where possible of effective delivery routes for comparable schemes.

Delivery and administration:

- BEIS should be strongly encouraged not to invent their own system
- BEIS should use existing infrastructure through schemes that are already in place such as under RED and the RTFO.
- There may be scope for third party organisations with experience in the management and development of industry schemes to undertake this role such as REAL who run the GGCS scheme, and the Biofertiliser Certification Scheme and Compost Certification Scheme (which are much more like the proposed H_2 standard than the GGCS).
- This could mirror the use of 'voluntary schemes' under the RED and RTFO. Once BEIS has taken a view on the robustness of a scheme, the detailed implementation

and auditing is carried out by the schemes themselves – greatly simplifying the process for government and industry

Q37. Should default data, actual data or a hybrid approach be used to assess GHG emissions? Please explain the benefits to the approach you have suggested.

As specified earlier in the response, a hybrid approach would be the preferred option. Having a list of default values would help industry initially and be more cost and time effective, but when these are not available (and if they were available), industry should still have the flexibility to measure and report actual values. These default values could be refined over time as the sector develops.

Similar approaches are used under a number of other energy policies including RHI, RTFO, FITs and RO.

Q38. What should the options be for reporting and verification of low carbon hydrogen? Do any of the options outlined seem appropriate? Are any of these particularly problematic?

Most members so far have been supportive of Self-Reporting, as this option is seen as the most time and cost-effective option. A similar approach is adopted under other energy policies like the RHI, and RO. However, like in these other policies, we would also recommend an annual third-party verification process to ensure the standard is robust and credible.

Q39. Are any other options not listed here that are better suited for low carbon hydrogen reporting? Any thoughts on how possible trade-offs between accessibility and robustness or between accuracy and simplicity could be addressed?

A materiality threshold should be used to prevent unnecessary time expenditure on items that do not have a material effect on emissions.

A member highlighted that there should be a distinction between elements that are within a producer's control (such as capture rate) and those that are outside its control (e.g. hydrogen distribution network). A simpler approach should be sought for those elements outside the producer's control.

Q40. What would be an appropriate frequency for verification or audit?

Once a year - this would fit with other equivalent schemes.

Q41. Over what period of time should the standard be introduced?

As soon as possible. And clarity is required on this, even before any financial incentives are put in place to enable project pipelines to be further developed.

Q42. Do you have any other comments relating to the carbon standard proposals set out in this document?

No further comments.