Hydrogen Europe

Hydrogen Europe Position Paper

Low carbon hydrogen: key principles for a coherent methodology in the upcoming Delegated Act

May 2024

Summary of policy recommendations

General recommendations

- Speedy adoption and simplicity **of the rules are of the essence.**
- **Ensuring** consistence with RFNBO DAs **(DA 2023/1184 and 2023/1185) by:**
    - **Keeping the same greenhouse gas (GHG) reference of 94 gCO2/MJ for calculating the 70% threshold in both transport and industry applications**
    - **Allowing for the same electricity sourcing strategies** for both RFNBO and low carbon hydrogen producers
    - **Same rules for allocation of GHG emissions to hydrogen and other co-products.**
- When policy options chosen under the upcoming Low carbon hydrogen DA deviate from the methodology under the RFNBOs DAs, this should be considered as grounds for the revision/amendment of the existing rules under the RFNBOs DA.

Specific recommendations

Some rules for low carbon fuels should be adapted to the various low-carbon production pathways, with different sets of factors to be considered. New rules need to mirror these fundamental differences and for this reason we propose:

- **A distinct regulatory framework for using dispatchable low-carbon electricity** that will reflect the characteristics of dispatchable sources and enable low carbon hydrogen producers to sign PPAs with low-carbon electricity sources.
- **Clear and unambiguous rules for establishing emissions from the use of waste heat:** while full carbon intensity of waste heat should be accounted for, waste heat used for high temperature electrolysis should not contribute to the energy character of the final fuel (i.e. the character of produced hydrogen should be defined by electricity inputs).
- **Increased accuracy and flexibility of natural gas upstream emissions accounting** by using project specific values.
- **Tailoring the allocation of emissions to by-product hydrogen** following a similar approach as for the RFNBOs and RCFs for existing installations, where a substitution approach should be adopted, while for new installations, the emissions should be allocated based on relative energy content (in case hydrogen is co-produced with other fuels) or based on economic value in other cases.
- **Equal recognition of all carbon removal solutions** to make sure that other (than CCS) means of permanent and long-lasting CO2 and carbon binding technologies are given the possibility of being deduced from the carbon footprint of a fuel, bringing the approach in line with the new Certification Framework for Carbon Removals.
- **A scientific approach to introducing a methodology dealing with hydrogen leakage, based** on careful evidence-based and fact-checking processes to be carried out in close collaboration with the industry, preceded by a definition of what constitutes hydrogen leakage and an extensive testing campaign.

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1. Introduction

1.1.1. Low-carbon hydrogen: in search of precise criteria

Low carbon hydrogen (LHC) can be produced by employing a wide range of technological pathways such as the following, but not limited to:

- Electrolysis (low and high temperature);
- Reforming with carbon capture (SMR, ATR with CCS);
- By-product hydrogen not classified as Recycled Carbon Fuel (RCF);
- Methane splitting (pyrolysis of methane).

The definition of what constitutes low-carbon hydrogen is provided in the Directive on common rules for the internal markets in renewable and natural gases and in hydrogen (part of the Gas & Hydrogen Package)[1], in article 2(10)):

''Low-carbon hydrogen' means hydrogen the energy content of which is derived from non-renewable sources, which meets the greenhouse gas emission reduction threshold of 70% compared to the fossil fuel comparator for renewable fuels of non-biological origin set out in the methodology adopted according to Article 29a(3) of Directive (EU) 2018/2001. It also details what is considered as 'low-carbon fuels', of which low-carbon hydrogen is a sub-set[2].

Following article 9(5) of the same directive: "*by … [12 months after the date of entry into force of this Directive], the Commission shall adopt delegated acts (…) to supplement this Directive by specifying the methodology for assessing greenhouse gas emissions savings from low-carbon fuels. The methodology shall ensure that credit for avoided emissions is not given for carbon dioxide from fossil sources the capture of which has already received an emission credit under other provisions of law and shall cover the life-cycle greenhouse gas emissions and consider indirect emissions resulting from the diversion of rigid inputs. The methodology shall be consistent with the methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels including the treatment of emissions due to the leakage of hydrogen and take into account methane upstream emissions and actual carbon capture rates.*

1.2. Low Carbon Hydrogen is important for the energy transition

Low carbon hydrogen (LCH) is an essential piece of the emerging hydrogen economy that will, in our opinion, play a significant role in the energy transition. Especially in the market ramp-up phase, it will be required for several decarbonisation purposes, where renewable hydrogen is not yet available in sufficient quantities or at sufficiently affordable prices. Along with RFNBOs, RCFs and biohydrogen, it can help quickly replace grey H2, and other unabated fossil fuels across the economy. In parallel to the crucial scale-up and uptake of domestically produced and imported RFNBOs mandated by renewable targets in the EU legislation such as the Renewable Energy Directive (RED), LCH can help accelerate the hydrogen market's build up beyond these existing targets. This will happen when the market for clean H2 and its derivatives will be more liquid, making hydrogen a genuine commodity

1 Yet to be published in the Official Journal

2 *As defined in Article 2 of Directive (EU) 2018/2001, low-carbon hydrogen and synthetic gaseous and liquid fuels, the energy content of which is derived from low-carbon hydrogen, which meet the greenhouse gas emission reduction threshold of 70% compared to the fossil fuel comparator for renewable fuels of non-biological origin set out in the methodology adopted according to Article 29a(3) of Directive (EU) 2018/2001.*

(that is competitive and abundant), and thereby providing clear signals as regards infrastructure investments.

1.3. The market needs clear and coherent rules as soon as possible

Because of the importance of the low carbon hydrogen pathways outlined above, the new rules contained in the upcoming Low Carbon Hydrogen Delegated Act (LCH DA), as explained in section 1.1., are crucial for the entire hydrogen sector. They will guarantee regulatory certainty required for investments to happen at the pace expected by all stakeholders. The upcoming Delegated Act with a methodology enabling the assessment of GHG emission intensity of low carbon fuels[3] will complement the so called RFNBO DAs from June 2023[4], and hence should be presented by the Commission as soon as possible to ensure an effective stakeholder engagement and a rapid adoption of the rules.

The Hydrogen sector, represented by over 570 companies and associations under Hydrogen Europe, is convinced this DA is crucial as it will enable a clear distinction between renewable (RFNBO and bio-hydrogen), RCF and LC hydrogen, and thus apply respective regulations accordingly to clear definitions. The LCH DA is going to be equally important for project developers focusing on RFNBOs since whenever renewable energy based PPAs are going to be complemented with grid electricity, there is almost always going to be a simultaneous production of RFNBO and LC hydrogen[5]. Finally, it will be decisive in enabling and facilitating the certification process on hydrogen market.

Hydrogen Europe has prepared a set of recommendations regarding the content of the upcoming Delegated Act.

[3] If that intensity is at least 70% below the fossil fuel comparator then a fuel will be considered to be low carbon

[4] Delegated Regulation (EU) 2023/1184 of 10 February 2023 establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin accessible here and Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023 supplementing Directive (EU) 2018/2001 by establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels accessible here

[5] Whenever electricity taken from the grid, not recognised as fully renewable following the Delegated Regulation (EU) 2023/1184, is used for electrolysis, only a portion of hydrogen produced, equal to the share of renewable energy in the electricity-mix, could be considered RFNBO, with the remaining part being considered as low-carbon hydrogen.

2. Hydrogen Europe Recommendations

2.1. General recommendations

- **Speedy adoption and simplicity of the rules are of the essence**: low carbon hydrogen requires robust methodology contained in the upcoming Delegated Act (Regulation). Still, for our sector it is essential that time is not lost in too lengthy creation and implementation of such Delegated Act, as it was the case with the RFNBO-DAs, so that investments aren't held back, and projects aren't delayed. The same goes for making sure that new rules are as simple and hence as easily applicable as possible to reduce red tape and administrative burden as well as accelerate the certification process of LCH.

- **Ensuring consistence with DAs 2023/1184 and 2023/1185….** We endorse the need to ensure consistency with the methodology for assessing GHG savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels as developed under DA 2023/1185. Having a coherent legislative framework for various production pathways is paramount for the viability of emerging projects. This consistency should be translated into:

    - *Keeping the same GHG reference of 94 gCO2/MJ for calculating the 70% threshold*: The GHG reference against which the 70% GHG avoidance is calculated must be aligned with the GHG reference applying to RFNBO in transport sector and should be extended to all RFBNO and Low Carbon fuels used in industry sector.
    - *Allowing for the same electricity sourcing strategies for both RFNBO and LCH producers:* opening the possibility of sourcing low carbon electricity via PPAs for low carbon hydrogen producers should be followed by a similar provision in the DA 2023/1185.
    - *Same rules for allocation of GHG emissions to hydrogen and other co-products*.

- **….. While also crafting the rules that will reflect some fundamental differences between renewable and low-carbon production pathways**. A coordinated and coherent framework is needed for low-carbon and renewable hydrogen to optimise their production potential. Nerveless, the rules for low carbon fuels should be adapted to the various low-carbon production pathways, with different set of factors to be considered[6]. New rules need to mirror these fundamental differences and for this reason we propose:

    - *A distinct regulatory framework for using dispatchable low-carbon electricity* that will reflect the characteristics of dispatchable sources and enable LCH producers to sign PPAs with low-carbon electricity sources.
    - *Clear and unambiguous rules for establishing emissions from the use of waste heat:* while full carbon intensity of waste heat should be accounted for, waste heat used for high temperature electrolysis should not contribute to the energy character of the final fuel (i.e. the character of produced hydrogen should be defined by electricity inputs).

[6] For instance, nuclear hydrogen is not always electrolytical (thermochemical splitting of water), electrolytical nuclear hydrogen does not behave like renewables either, and much of the low carbon hydrogen will come from paths that are non-electric (like SMR or ATR with CCUS).

- *Increased accuracy and flexibility of natural gas upstream emissions accounting* by using project specific values.
- *Tailoring the allocation of emissions to by-product hydrogen* to follow a similar approach as for the RFNBOs and RCFs for existing installations, where a substitution approach should be adopted, while for new installations, the emissions should be allocated based on relative energy content (in case hydrogen is co-produced with other fuels) or based on economic value in other cases.
- *Equal recognition of all carbon removal solutions* to make sure that other (than CCS) means of permanent and long-lasting CO2 and carbon binding technologies are given the possibility of being deduced from the carbon footprint of a fuel, bringing the approach in line with the new Certification Framework for Carbon Removals.
- *A scientific approach to introducing a methodology dealing with hydrogen leakage*: the rules for defining maximum leakage rates require careful evidence-based and fact-checking process to be carried out in close collaboration with the industry, preceded by a definition of what constitutes hydrogen leakage.

- **Finally, in cases where certain policy options are chosen under the upcoming LCH DA and deviate from the methodology created under the RFNBOs DA framework, this should be considered as grounds for the revision/amendment of the existing rules under the RFNBOs DA. This is to make sure consistency is de facto being safeguarded, and the rules are facilitating final investment decisions**.

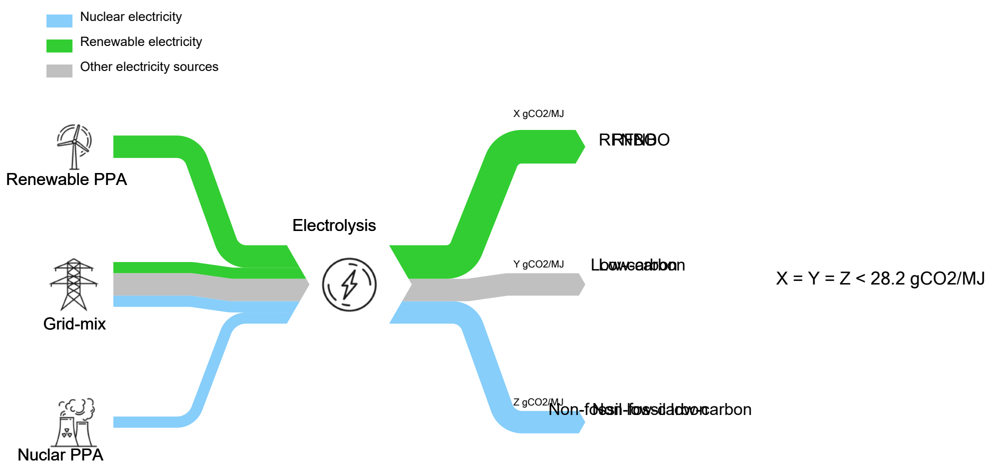
2.2. Detailed suggestions

2.2.1. Regulatory framework for using dispatchable low-carbon electricity

The RFNBO DAs (Delegated Act 2023/1184 on electricity sourcing and the delegated act 2023/1185 on GHG emissions methodology) [7] allow for accounting "fully renewable" or 100% renewable electricity and give that renewable electricity an emission factor of zero. Alternatively, the RFNBOs producers can also use the grid mix values (in terms of renewable share and carbon footprint). The DA 2023/1184 does not allow to account for any other form of low-carbon electricity (e.g. nuclear, existing renewables) through a PPA or otherwise.

For the LCH DA, Hydrogen Europe advocates for an approach that would allow producers to also sign PPAs with dispatchable low-carbon electricity sources - other than renewable - in line with the Gas Package definition of Low Carbon Hydrogen.

- This includes, for instance, electricity produced from nuclear sources as well as from waste incineration plants.
- We propose that the PPAs signed with low-carbon electricity sources are not covered by any form of additionality requirement.
- We also recommend that whenever electricity is taken from the grid, provided that the overall GHG emission threshold of produced hydrogen is respected, the portion of the hydrogen output equal to the share of nuclear electricity in the bidding zone's electricity mix should be recognized as **non-fossil** low carbon hydrogen, and thus be eligible for ReFuelEU Aviation[7] (see illustration below).
- The emission intensity of grid electricity should be assessed using the same GHG methodology as in the case of RFNBOs - including average GHG emission intensity of electricity at country or bidding zone level (table A part C of Annex from DA 2023/1185).
- To ensure consistency, the proposed provisions should be also added to the DA 2023/1185.



[7] The definition of 'synthetic low-carbon aviation fuels' in the ReFuelEU Aviation regulation included fuels, the energy content of which is derived from non-fossil low-carbon hydrogen. These fuels are eligible for proving compliance with the minimum shares of SAFs set by the regulation.

Justification:

The proposed approach would ensure the utilization of low-carbon sources is maximised, while recognizing that dispatchable low-carbon electricity supply is much more elastic that renewable one.

Also, our proposal for a recognition of nuclear share of the electricity in bidding zones is fully consistent with what already exists for recognition of renewable energy share in the grid mix under the RFNBO framework[8] and presents the benefit of enabling the LCH derived from nuclear electricity to be eligible for ReFuelEU Aviation.

Any option for sourcing low-carbon electricity, other than renewable, that is put forward in the upcoming LCH DA must also be added to the RFNBO DAs. This would not only serve the purpose of harmonising the rules but would also be beneficial for RFNBO production - especially for industrial off-takers. Indeed, supply of hydrogen for industrial applications, with limited demand side flexibility, is extremely challenging in the context of hourly temporal correlation under the RFNBO DA. Especially in bidding zones where the average grid carbon intensity is high, RFNBO hydrogen project developers are forced to opt for expensive PPA that need to be over dimensioned, and/or for expensive energy storage solutions. Allowing them to balance variable renewable energy via low-carbon dispatchable electricity sources could therefore lead to significant renewable hydrogen production cost reduction.

[8] If an RFNBO production plant operator mixes renewable electricity with grid electricity in a way that the average carbon intensity of the mix stays low enough so that hydrogen produced is below 28.2 gCO2/MJ, that enables the operator to obtain RFNBO hydrogen not only for the portion equal to share of RE PPA, but also for the % of grid electricity equal to the share of renewables in the grid mix.

2.2.2. Emissions factor from waste heat use

High temperature electrolysers, such as Solid Oxide-based, commonly use waste heat recovered from industrial processes as input (other than electricity), increasing their overall efficiency. As a rigid input, waste heat should have an emission factor based on a counterfactual scenario. If that heat was being wasted (not recovered), it would have an emission factor of zero. But if the same waste heat was being recovered, for instance for space heating purposes, its emission factor would be equivalent to the solution that would be used as a substitute for that heat (e.g. emissions from natural gas combustion).

While such an approach is sound and can be replicated for low-carbon fuels, Hydrogen Europe would like to point out that the methodology would benefit from two main clarifications and simplifications:

- It should be **clarified** that **waste heat used for high temperature electrolysis** (or other production pathways) **does not contribute to the energy character of the final fuel** (i.e. if electricity is 100% fully renewable or low-carbon, then the hydrogen produced is also renewable/low-carbon with the carbon intensity of waste heat contributing to the carbon footprint of the fuel);
- In case of **using waste heat from new (and not existing) installations,** where determining the existing use of heat is possible, or for installations in which the hydrogen production recovery is demonstrated to be the most efficient recovery path, **the carbon intensity of waste heat (as an opportunity cost) should be zero and not based on the next best economic alternative.**

Justification:

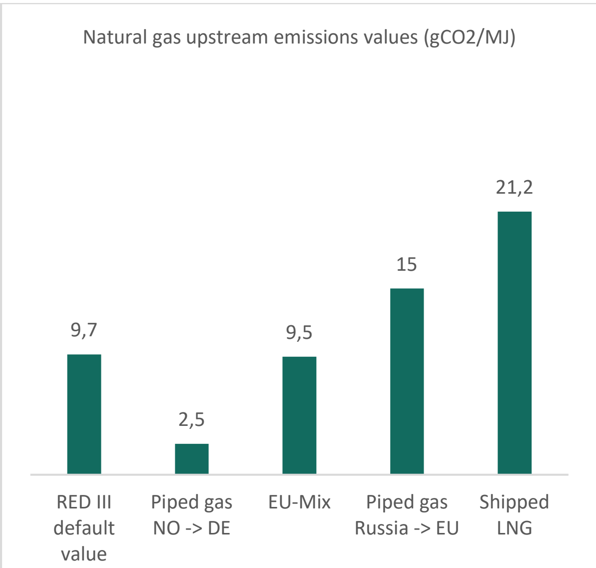
- In general, in the EU legal framework stemming from the Winter Package and Fit for 55, waste heat is not seen as "waste" per se (i.e. its equal treatment with RES in the heating sector). Its use, when available, is considered as a way to increase energy efficiency, which also contributes to the EU efficiency target. The same treatment should be applied to heat recovered from the production of hydrogen.
- Not all waste heat recovery is systematically substituted by natural-gas based combustion – as other means can also be used to replace the heat, with much lower emission factors (e.g. heat pump, boiler with renewable gas). The methodology should provide incentives for redirected heat to be replaced with low-carbon alternatives.
- The existing methodology (for RFNBO/RCFs) is very hard to justify for new installations. There is no justification for burdening low-carbon fuels with entirely theoretical emissions, based on hypothetical next best economic alternative scenarios. This does not only introduce unnecessary risk for investors, but it is also unjustified from the point of view of GHG accounting accuracy.
- If hydrogen production is the most efficient local recovery path, there is no counterfactual scenario or opportunity cost in this use.

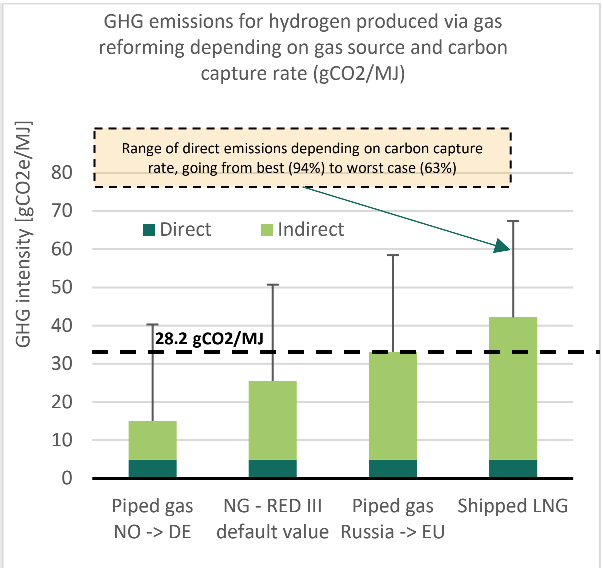
These elements should be reflected in the new LCH DA, also creating an opportunity to amend the rules in this field in the existing RFNBO DA. Indeed, the latter lacks an explicit definition of what is the relevant emission factor in case of waste heat (heat produced by combustion of natural gas or the actual project specific source of heat?). A revision would be a welcome opportunity to provide that clarification, while also introducing a more accurate take on calculating the emissions factor from waste heat use.

2.2.3. Default value for accounting for natural gas upstream emissions

The Delegated Regulation (EU) 2023/1185 sets an upstream emissions factor default value for natural gas of 9.7 gCO2/MJ for RFNBOs and RCFs GHG emissions savings calculation. For RFNBO fuels, the use of natural gas as input is very limited, and thus, it is understandable that a default/harmonised value would be applied.

This however is not the case for low-carbon fuels and low-carbon hydrogen production, where natural gas could be the main feedstock or energy input – hence a more targeted approach is needed, to accurately capture GHG savings offered by LCH technologies. As illustrated below, the value used for the DA 2023/1185 is closely linked to an average EU emission factor.





Source: Hydrogen Europe based on RED DA, Equinor 2021, DBI 2021, JEC WTW study 5.0 2020, US DOE GREET 2023

Because of this difference**, Hydrogen Europe recommends a more flexible approach, which allows for project promoters to calculate the project specific GHG emissions intensity of used natural gas based on the origin of gas inputs used. The LCH DA would have to specify the methodology the project promoters can follow to calculate the project specific gas emission intensity. Furthermore, we call on the European Commission, in collaboration with national energy regulators, to work on establishing a set of national default values for gas emission intensity, as has been done for the average emissions of electricity intensity in the 2023/1185 DA (table A, part C). These values should be periodically reviewed**.

Justification:

- In LCH production pathways, gas related emissions would represent a large share and hence, the value of the default upstream emission factor for natural gas could be a deal breaker in terms of qualifying or not as LCH (whether it is above or below the 70% threshold of GHG savings with respect to the fossil benchmark). Also, and more importantly, it would disincentivise the project promoters from seeking to use gas sources with the lowest possible carbon intensity (e.g. local gas sources or natural gas from efficient transporters/supply sources). Following that logic, a single emission factor would prevent GHG accounting based on the real gas supply chain originated by the project promoter. Opening the option of project specific calculations creates an incentive for LCH producers to source their natural gas from a specific provider who can certify a lower-than-average GHG footprint.

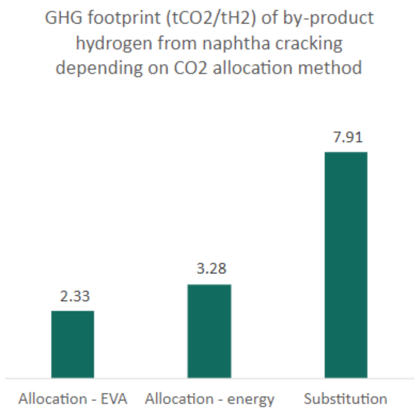
- At the same time, ramping up the emerging hydrogen market will require to grant access to different market players and to prevent excessive red tape. Allowing the use of national default values predefined in the DA will enable non-integrated players to produce LCH with natural gas sourced from the gas grid without additional administrative burden. For that reason, this option should still be available.

For a project specific default value, a transparent, credible and accurate mechanism with independent third-party verification should be established to track the GHG emission intensity of natural gas production and supply to Europe. In addition, LCH producers should make sure the GHG emission intensity of the LCH is fully transparent. The DA would have to specify the methodology of that calculation and emissions accounting, while also enabling recognition of existing certification schemes[9], when assessing upstream supply chain emissions. The introduction of national default values would add flexibility and simplify the process – especially important for small scale projects.

[9] For instance, MiQ, along with similar certification schemes, already verifies methane emissions in accordance with the requirements outlined in the US IRA's section 45V. This includes the use of independent, accredited third-party verifiers. A similar approach could be used in the LCF DA. The MiQ Registry oversees the issuance of the certificates, ensuring they meet the same rules required by Section 45V. This involves assigning unique identification numbers to each MMBtu issued, recording geographical and facility source information, and timestamping the data. Retirement statements from retired natural gas emission certificates can be used as credible and direct evidence for project specific value of the natural gas upstream emission factor under the LCF DA and verified by a third party verifier/auditor.

2.2.4. Allocation of emissions to by-product hydrogen

Choosing the right allocation method for emissions of by-product hydrogen is also a challenge in the framework of this upcoming LCH DA. The GHG footprint of a by-product hydrogen can be significantly different depending on whether an allocation[10] or a substitution approach[11] is chosen (see an illustration below).



In order to preserve the same approach as has been adopted for inputs for the production of Recycled Carbon Fuels (defined in the RFNBO DA), Hydrogen Europe proposes that **for existing installations, a substitution approach should be taken**, with the carbon intensity of hydrogen depending on the carbon intensity of the fuel it will be replaced with, when redirected from its current use.

At the same time, the project promoters should be given an incentive to replace the redirected hydrogen with low-carbon alternatives, therefore **the counterfactual should always be project-specific and not rigidly pre-defined**.

For new installations, where no counterfactual exists, the emissions should be allocated based on relative energy content (in case hydrogen is co-produced with other fuels) or based on economic value in other cases.

Consequently, the RFNBO DA would require appropriate amendments to ensure coherence.

Justification:

The suggested approach is coherent with the existing rules for redirected inputs used to produce recycled carbon fuels, while also providing sufficient incentives for current use of by-product hydrogen to be replaced with low-carbon alternatives. For new installations, where no counterfactual scenario exists, avoiding the use of theoretical 'next–best economic alternative' as basis of GHG calculation will reduce risk for investors.

[10] If so, what should the allocation be based on? Here, GHG allocated to all co-products according to energy content or economic value. Energy content whenever a product has calorific value (irrespective if it is used as a fuel), and economic value in all other cases.

[11] GHG allocated to hydrogen based on the emission intensity of the fuel it was replaced with after being redirected from its current use. This approach raises a lot of questions, for instance: should the assumption be that H2 is always replaced with natural gas? Should project promoters be able to replace H2 with e.g. biomethane to claim lower emissions?

2.2.5. Recognition of permanent CCU and allocating credits

In the RFNBO DA 2023/1185, captured CO2 can only be deducted from the carbon footprint of the fuel in case of geological storage. The possibility of permanent CCU is not recognised.

$$E = e_i + e_p + e_{td} + e_u - e_{ccs}$$

e_{ccs} = emission savings from carbon capture and <u>geological storage</u> (gCO2eq / MJ fuel)

Hydrogen Europe recommends a more flexible approach, especially when it comes to recognition of other means of permanent and long-lasting CO2 binding technologies (e.g. mineralisation for use in industry and construction materials, and chemical feedstocks), bringing the approach in line with the Certification Framework for Carbon Removals[12]. The minimum lifetime for CCUS should be aligned with the Certification Framework proposal.

*e_{ccs} = emission savings from carbon capture and <u>geological storage,</u> <u>**as well as carbon capture and use with long term carbon sequestration**</u> (gCO2eq / MJ fuel).*

Furthermore, the methodology should also be flexible enough to ensure that the carbon credit is not limited only to captured CO2 but includes also solid carbon, for example from hydrogen from pyrolysis (i.e. pre-combustion carbon capture).

<u>Justification</u>:

This more permissive take would align with the recently published EU Industrial Carbon Management Strategy[13], which seeks to develop technologies to capture, store, transport and use CO2 emissions from industrial facilities, as well as to remove CO2 from the atmosphere. These include Capture of CO2 for storage (CCS), removal of CO2 from the atmosphere, but also Capture of CO2 for utilisation (CCU), defined as when "CO2 is used to substitute fossil-based carbon in synthetic products, chemicals or fuels"[14].

The strategy also states that for carbon capture and use, "*the Commission plans to assess options to increase the uptake of sustainable carbon as a resource in industrial sectors (including chemicals, advanced synthetic fuels, polymers, or minerals). It will also draw up a coherent framework to account*

[12] Provisional Agreement on the Regulation establishing a certification framework for carbon removals accessible here

[13] Communication from the Commission "Towards an ambitious Industrial Carbon Management for the EU" from February 2024, accessible here. It will complement and complete existing EU policies and funding instruments, notably the CCS directive for geological storage, the EU's Emissions Trading System (ETS), the proposed EU certification framework for carbon removals, the Net-Zero Industry Act, as well as support for CO_2 transport infrastructure under the TEN-E Regulation for cross-border energy projects, the EU's Innovation Fund and the Connecting Europe Facility

[14] For the latter, the strategy recognizes that "*by replacing fossil-based feedstocks, CCU can contribute to emission reduction, energy security and autonomy of the EU*". Yet, "(….) *the benefits of these CO2 utilisation technologies are not yet fully recognised, nor is their capacity to provide an alternative source of carbon to replace fossil carbon in specific sectors of the EU economy that are carbon-dependent*".

for and support the deployment of innovative and sustainable CCU applications (….) *The Commission is preparing a delegated act [in the framework of the revised EU ETS directive] to specify the conditions under which permanent storage can be recognised, to put permanent CCU and CCS on an equal footing in the ETS.* Consistent with the EU ETS framework, the co-legislators also agreed in February 2024 on the adoption of the EU carbon removal certification framework that aims to give the option to voluntarily certify carbon removals by storing atmospheric or biogenic carbon in products (amongst other means) in a manner that prevents the carbon from being re-emitted to the atmosphere permanently or for at least 35 years (for long-lasting products).

In addition to the ETS-warranted clarifications on RFNBO zero-rating expected shortly in the updated Monitoring and Reporting Regulation (MRR), this placing of CCS and permanent CCU on equal footing should be reflected in the upcoming LCH DA as well as open the window of opportunity to ensure the same treatment of CCU in the RFNBO DA.

2.2.6. Hydrogen leakage

Article 9(5) of the Gas Package Directive specifies that the methodology established through the LCH DA shall be consistent with the methodology for assessing GHG savings from RFNBOs and RCFs, *"including the treatment of emissions due to the leakage (….)"*. Paragraph 6 of the same article further elaborates that the Commission will come up with a report that evaluates hydrogen leakage, including, among other calculations, adequate maximum hydrogen leakage rates. Subsequently, the EU executive shall submit a legislative proposal to introduce measures to minimize possible risks of hydrogen leakage, set maximum hydrogen leakage rates and compliance mechanisms. Relevant maximum hydrogen leakage rates shall be included in the methodology referred to in paragraph 5. That could indicate that the LCH DA should already provide a methodology to set up relevant maximum hydrogen leakage rates.

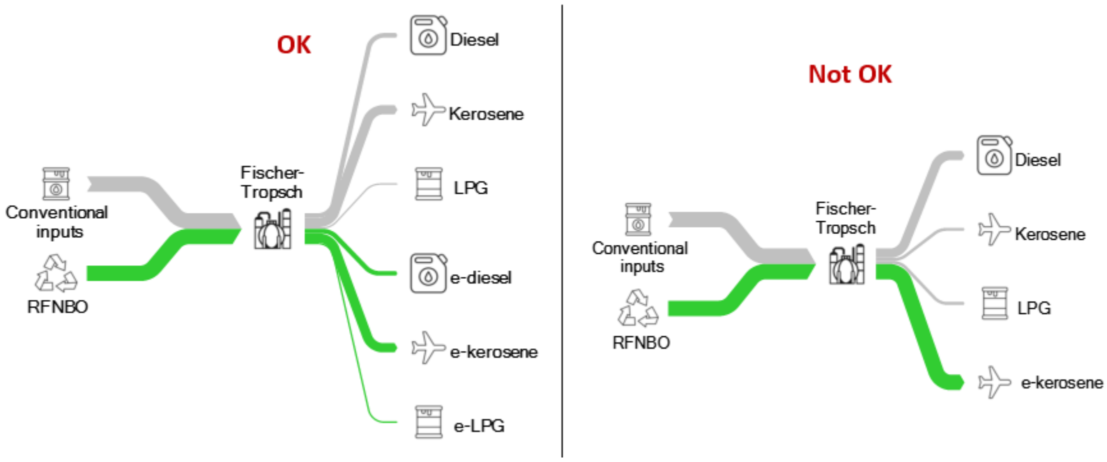
Hydrogen Europe calls for a very cautious approach on this issue. While the hydrogen sector needs the LCH DA as soon as possible, setting the rules for defining maximum leakage rates will require scientific processes to be carried out in close collaboration with the industry.

Justification:

- The future EC report as well as the legislative proposal mentioned in article 8(5) and (5b) do not yet have a definitive date set (for both the proposal and its eventual adoption). It means that the issue of hydrogen leakage does not necessitate immediate tackling in the framework of this LCH DA (to comply with the needs of subsequent legislative proposal on H2 leakage) and could be addressed in the subsequent iteration/revision of the LCH DA, once some of the required practical experience has been gained.
- For now, there is no clear definition of what constitutes hydrogen leakage. A first step would be to agree on said definition as it would not only help our sector but also require active participation and consultation of all relevant stakeholders across the entire value chain. The same goes for the understanding and development of prevention measures.
- In addition, as of now, there is no Global Warming Potential (GWP) value defined by the IPCC (i.e. GWP of 0 for H2) and without GWP being established, defining a maximum leakage rate would be premature. If a GWP value were to be introduced in this legislation, it would then also have to apply in RFNBO DAs and would require their amendment.
- In our view, at present, the attention of the EU executive should be focused on creating the most optimal conditions for the development and broad application of hydrogen leakage detection technologies before any stringent rules are being put in place.

2.2.7. Free allocation of energy origin to products

The RFNBO DA stipulates that in cases where RFNBO/RCFs are co-processed with conventional inputs, it is possible to calculate the emission intensity separately for conventional products and RFNBO products. It is however not possible to freely allocate the renewable character to only selected products of choice (it must be proportionally allocated to all ''renewable outputs'').



Such an approach is proving to be highly challenging, especially for existing installations and hinders production-projects from reaching final investment decision because companies do not find any wiliness to pay a premium in the diesel and/or LPG markets.

Due to the relatively small operational scale of sustainable fuels plants, it is not commercially advisable to operate downstream refining steps in the same facility. It is far more efficient to perform this step separately in conventional refineries (co-processing). Green- and brownfield alternatives exist, whereby the latter offers a significant advantage with regards to capital requirements.

The production of low carbon fuels as well as the processing to final products appear to be a bottleneck today, due to various reasons, and must be unblocked to accelerate the sustainable fuels ramp-up.

The producers of low carbon fuels via co-processing in conventional production facilities and refineries (brownfield) will require additional regulatory support in the form of flexible allocation of 'low carbon credits', whereby incremental 'low carbon' / sustainable inputs can be freely/flexibly allocated to a selected product within the product slate (e.g. aviation fuel). This is to maximise on the sustainable volumes of that particular product, for which there is a demand and incentives to afford the low carbon premiums associated with those products. In doing so, revenue can be recycled into increasing the sustainable inputs, which will facilitate a gradual transition of these facilities aligned with just transition imperatives (in developing economies). Allowing flexible allocation of 'low carbon credits' to selected co-products would lead to production of higher volumes of sustainable fuels. **This approach also needs to be recognised under the RFNBO delegated act.**

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