BEE Position

on the Draft delegated Regulation on the methodology for assessing greenhouse gas emissions savings from low carbon fuels

Berlin, October 25th 2024

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Short Summary

- Any set of rules must ensure that the production and consumption of renewable hydrogen products (such as RFNBOs) always takes priority over the production and consumption of low-carbon hydrogen products (such as LCFs).
- Both feed-in priority and the introduction of consumption quotas play an important role in ensuring the primacy of renewable hydrogen products.
- The legal framework must not allow electrolysis operators to increase their full load hours by combining the production of RFNBOs and LCFs. It has to ensure that electrolyzers act as a flexibility in the energy systems.
- A discrimination against other gases based on renewable energies such as biomethane, synthetic renewable methane and biogenic hydrogen has to be avoided.
- When determining GHG emissions of hydrogen that uses natural gas-based processes such as steam reforming, it is important to take into account all upstream, midstream and downstream emissions of the production chain. The rules must not contradict the requirements already set out in RED II / III.
- Companies should be required to have their project-specific emission measurement values certified externally.
- The default value of 5g CO2eq/MJ for upstream methane emissions is too low and should be raised to 15g CO2eq/MJ. This higher value would encourage the determination of the actual emissions values.
- A fixed time limit should be set by which the EU Commission must prepare a report on the status of a possible quantification methodology for emissions from hydrogen leaks.
- The GHG footprint of this electricity used during during steam reforming processes has to be the is taken into account when calculating the total LCF emissions.
- The required CO2 for the produciton of hydrogen derivatives should primarily be taken from biogenic sources (Bioenergy with Carbon Capture and Utilization, BECCU).
- When it comes to attributing grid electricity to LCF production, the use of annual values combined with the possibility of a switch to hourly values in 2028, is problematic as it causes uncertainty among stakeholders. Instead the use of hourly values should already be introduced as an option now.
- Due to their negative implications the attribution of grid electricity to LCF production via the given options 2 and 3 has to be rejected.
- If option 2 is nevertheless retained, it must be ensured that it is not easier for producers of nuclear power to provide electricity for the production of LCFs than it is for producers of renewable energy to provide electricity for the production of RFNBOs.
- The rules of the assessment methodology for low-carbon hydrogen must also apply to imported low-carbon hydrogen. This has to be ensured via a strict certification system.

1 General principles for the design of the assessment methodology

Hydrogen can be produced in the electrolysis process using electricity. According to the current draft, electricity that does not meet the requirements for the production of renewable fuels of non-biological origin (RFNBO), but still complies with certain emission limits, can be used to produce low-carbon fuels (LCF). This should also apply to the production of hydrogen using natural gas-based processes such as steam reforming.

In this context, it must be stated that only the renewable hydrogen used to produce RFNBOs can make a decisive contribution to the desired energy system based exclusively on renewable energies and that only this kind of hydrogen is available to the grid as flexibility.

For this reason, it must be ensured by law that the **production and consumption of renewable hydrogen products (such as RFNBOs) always takes priority over the production and consumption of low-carbon hydrogen products (such as LCFs)**. This is particularly true due to the currently limited capacities of hydrogen in the gas network and of hydrogen storage facilities as well as limited demand volumes.

The priority given to renewable hydrogen and its derivatives should be ensured by both **giving priority when it comes to feeding those products into the gas networks** as well as by **introducing consumption quotas**. The latter ensure the offtake in the respective markets. Such quota arrangements have already been made in ReFuelEU Aviation, ReFuelEU Maritime and RED III (industrial quota), and similar arrangements should follow in the remaining sectors.

The BEE sees the **risk** that electrolysis operators will increase their full load hours by purchasing electricity from the grid and **applying the Grid Emission Factor in order to produce LCFs in addition to RFNBOs**. The legal framework must urgently prevent this. Electrolyzers should be flexible consumers that consume electricity in a way that benefits the system and not overload the grid by running 8,000 full load hours.

In addition, the legal framework applicable to LCFs (which may later also apply to other low-carbon hydrogen products) must **not discriminate against other gases based on renewable energies**. These include, in particular, biomethane, synthetic renewable methane and biogenic hydrogen. For these, greenhouse gas (GHG) emissions are already determined across the entire process chain, and these can also be negative (carbon sink).

2 Use of natural gas for the production of low-carbon fuels

2.1 Inclusion of all emissions from the hydrogen production chain

Natural gas-based low-carbon hydrogen should be subject to **comprehensive inclusion of all emissions along the production chain**.

It is crucial to establish clear system boundaries for the production of hydrogen using natural gas-based processes such as steam reforming, within which all GHG emissions are taken into account, including emissions from **upstream, midstream and downstream of the production chain**. This is intended to ensure that only those production plants that actually capture sufficient CO2 are certified as LCF.

In connection with the assessment of emissions from natural gas-based hydrogen products, the rules for methane and hydrogen leakages that occur during the production process are particularly relevant. It is also important to take into account the emission value of the electricity used in the steam reforming process.

Methan leakages:

The current draft states that methane leakages are to be taken into account in the form of CO2 equivalents as should be done with other kinds of emissions.

According to Art. 29 (4) of the Methane Regulation, the EU commisson must adopt a Delegated Act on the methodology for calculating the methane intensity of natural gas production by August 5, 2027 - the methology shall then also be applied to LCF.

Until then, the methane intensity is to be calculated on the basis of the values that plant operators must collect and report in accordance with Article 12 of the Methane Regulation. In cases in which project-specific methane emissions cannot be determined, a flat-rate 40% increase onto the baseline value of methane upstream emissions is to be estimated.

The BEE basically welcomes the fact that the current draft refers to Article 12 of the Methane Regulation, which enables the provision of project-specific values. However, **companies should be required to have these project-specific measurement values certified externally**. A tight control system must be implemented to exclude the possibility of misuse.

Moreover, the **BEE critizes the default value of 5gCO2eq/MJ that the current draft uses for upstream methane emissions**. Taking the US as a benchmark (from which large parts of the hydrogen derivates such as low carbon ammonia may be imported), those upstream methane emissions are estimated to be between 1 and 3% on average (with some regions going all the way up to 10%). The assumed 5graCO2eq/MJ equal 1 %, showing that it is a strong underestimation.

The default value is supposed to be valid until more detailed analysis has been performed and the EU can provide an exact upstream emission number per country. In this context, the BEE sharply criticizes the assumptions made regarding the default value for methane upstream emissions. Our association advocates that a default value should not encourage procrastination of investigating the actual value; it should encourage it. This is not the case with the default value currently set. The BEE therefore **suggests to raise the default to 15g CO2eq/MJ** (equaling 3 %) while maintaining the default increase of 40% as noted in the draft.

Hydrogen leakages:

The GHG emission potential of hydrogen leakages is not taken into account for the time being, as the required accuracy for calculating GHG emissions is considered insufficient.

As soon as there is a sufficient scientific basis for the GHG emission potential of these hydrogen leakages, the effect of these is supposed to be taken into account for both LCF and RFNBO across the entire supply chain.

Article 9(6) of the revised EU Gas Directive instructs the EU Commission, if necessary, to prepare a report on hydrogen leakages and submit it to the European Parliament and Council. Based on this, maximum hydrogen leakage rates could be defined, which could then be transferred to the delegated act.

The BEE welcomes the fact that the EU Gas Directive mandates the EU Commission to prepare a report on hydrogen leaks, but criticizes the lack of a time limit for this requirement. A **fixed time limit should urgently be set by which the EU Commission must prepare a report on the status of a possible quantification methodology for emissions from hydrogen leaks**.

Consideration of the emission value of the electricity used in the steam reforming process:

To produce hydrogen by steam reforming natural gas, electricity is typically used to extract methane and run the carbon capture unit. It is important to ensure that the **GHG footprint of this electricity is taken into account when calculating the total emissions of low-carbon hydrogen-based products** such as LCF.

2.2 Necessary provisions for the use of CCS technologies and CO2

All emissions generated during the carbon capture and storage (CCS) process must be fully included in the calculation of the emission content of low-carbon hydrogen.

When planning gas infrastructure, it should also be taken into account that a **pipeline network is required to transport the CO2 to be stored**. Competition for use with hydrogen or other gases should thereby be avoided.

Moreover, it is expected that not only hydrogen will be used in Germany, but also its derivatives, like methanol or e-fuels. The production of those products requires planning certainty about the availability of CO2 as a raw material.

The **required CO2 should thereby, first and foremost, be taken from biogenic sources** (Bioenergy with Carbon Capture and Utilization, BECCU). Direct air capture processes are also an option. The use of CO2 from fossil sources, however, is problematic due to its incentive effect, which runs counter to climate goals.

3 Use of grid electricity for the production of low-carbon fuels

Whether grid-based hydrogen will be low-carbon depends on the CO2 intensity of the electricity used. Operating an electrolyzer 24/7 with grid-sourced electricity can today lead to more emissions than the production of conventional fossil-based hydrogen. This must urgently be avoided urgently by setting an adequate regulatory framework.

The current draft for the delegated act provides three ways to attribute the grid electricity that cannot qualify as fully renewable in accordance with Article 27(6) of Directive (EU) 2018/2001 but is instead used to produce low-carbon fuels.

<u>Attribution via country- or bidding zone-dependent standard values</u>

Relying on GHG emissions values that shall be applied during the course of a whole calendar-year does not do justice to the current dynamics of the electricity grid. Therefore, only one method should be accepted: the use of hourly balanced emission values of the CO2 footprint in the respective electricity bidding zone.

Article 3 of the current draft announces a review for July 1, 2028, which may result in the introduction of an option to consider the above mentioned use of hourly balanced emission values of the CO2 footprint in the respective electricity bidding zone.

Instead of introducing an option for an annual average value now and possibly switching to hourly values in 2028, thereby causing uncertainty about the legal framework among the stakeholders involved, **the option to use hourly average values should already be introduced now**.

However, it is important to **ensure that the introduction of the option to consider the GHG emission intensity of the electricity based on averages in the production of LCF does not lead to disadvantages in the production of RFNBOs**. As a general rule, incentivizing the production and consumption of RFNBO should always take precedence over incentivizing the production and consumption of LCF.

<u>Attribution via a comparison of the full load hours of the LCF producing plant and the full load hours of the predecing calendar year in which the marginal price of electricity was set by installations producing renewable or nuclear energy</u>

In principle, the conditions that should apply for the use of grid electricity should be at least as strict for LCFs as they are for RFNBOs. In particular, it must not be easier for producers of nuclear power to provide electricity for the production of LCFs than it is for producers of renewable energy to provide electricity for the production of RFNBOs.

Additional electricity generation capacity should therefore also have to be built for low-carbon hydrogen. This could be achieved, for example, by requiring a PPA agreement between the respective electricity producers and the producers of LCFs, comparable to the regulations in the Delegated Act for RFNBOs.

In its current however the option **would offer a circumvention and also undermine the 90 percent rule in the Delegated Act on RFNBOs** and **is therefore to be rejected**.

<u>Attribution via the emissions value of the marginal unit generating electricity at the time of the production of the LCF</u>

If the attribution takes place via the greenhouse gas emissions value of the marginal unit generating electricity at the time of the production of the low-carbon fuels there is a risk that, for example, hydrogen peak load power plants are price-setting. In this case, the electricity from continuously operating fossil-based power plants could be used to produce low-carbon hydrogen, which should be avoided. **This option must therefore also be rejected**.

4 Necessary provisions for imports of low-carbon hydrogen or its derivatives

The rules of the assessment methodology for low-carbon hydrogen produced within Europe should urgently also apply to imported low-carbon hydrogen.

This means in particular that, first of all, the import regulations of the European Carbon Border Adjustment Mechanism (CBAM) may need to be expanded. As of today, this mechanism only includes direct emissions from the production of hydrogen. However, **indirect emissions**, e.g. from the consumption of electricity at various points in the production process, **should also be taken into account for imported hydrogen.**

To enable the import of hydrogen and its derivatives from outside Europe, a **suitable, strict certification system** must be established. To this end, suitable interfaces must be created to monitor compliance with the criteria on site.

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Our aim: 100 percent renewable energy in the areas of electricity, heat and mobility.

Imprint

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Date

14th February 2023