TRANSPORT & ENVIRONMENT

Thursday, 9 July 2020

Subject: Follow-up stakeholder meeting on 18 June 2020 on the delegated acts on a GHG methodology for RFNBOs and RCFs consumed in transport and on minimum GHG emission thresholds for RCFs

Dear Mr McDowell,

On behalf of Transport & Environment, we would like to share our views on the approach presented by the JRC on 18 June. For our views on the GHG methodology for Recycled Carbon Fuels, we refer to the letter, shared by Zero Waste Europe with you on 30 June. The comments below focus mainly on the regulatory framework for RFNBOs.

1. Formula for GHG emissions

Transport & Environment expresses its support for the general approach to calculate the lifecycle GHG emissions of RFNBOs and the proposed approach to simplify the accounting of the emissions by using the categories of major, minor and *de minimis* inputs.

The lifecycle GHG emissions of the inputs should include the supply and processing of the feedstocks for the production of the RFNBOs, the process emissions and their transport and distribution. This should include the direct emissions from energy use involved in producing an RFNBO that is ready to be used, including:

- Capture of nitrogen for the production of ammonia or the use of DAC to capture carbon for the production of carbon-based RFNBOs like e-kerosene, e-methanol or e-diesel,
- Processing by means of synthesis processes
- Transport and distribution by means of compression or liquefaction of hydrogen or ammonia.

To calculate the CO2 equivalence of the different GHG (CO2, N2O and CH4), the JRC proposed to use the Global Warming Potential of these GHG over 100 years. We object in particular to the GWP value of 25 for CH4 (slide 13 of the JRC presentation), which is not in line with the GWP value of methane in the 5th Assessment Report of the IPCC. For short-lived climate pollutants (SLCPs), such as methane, **assessing GWP over a shorter time frame of 20 years** in parallel to an assessment over 100 years provides valuable policy insights into the best way to reach our overall emission reduction goals.

SLCPs can have a huge climate impact in the short-term which is not revealed by statistics that only consider a 100-year GWP. For example, methane is 84-86 times more polluting than carbon dioxide over a 20-year time, but from a 100-year perspective it is 28-34 times more polluting than CO2.[1] As a result, processes that have high methane emissions are perceived as less damaging to the climate than they are in reality, when only looking at the GWP100. GWP20 reflects more accurately the short term climate impact of using fossil methane as a transport fuel. Any benefits from using fossil gas in road or marine transport -

[1] IPCC (2018) Anthropogenic and Natural Radiative Forcing . Retrieved from https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf (table 8.7)

even with relatively low fugitive methane emissions along the supply chain - would only materialise several decades into the future, well after the EU economy would need to be fully decarbonised. Dual accounting of both GWP100 and GWP20 is crucial: This will reveal the huge potential in emissions savings that will result from tackling these SLCPs and guide policy decisions that can significantly contribute to emission reduction efforts over the next 30 years to the goal of net-zero by 2050.

2. Accounting for emissions of inputs

For RFNBOs, the elastic vs. rigid input allows to make a clear distinction between the energy (in the form of electricity or heat)[2] that is truly additional and the energy that is not. The RED II (recital 90) offers guidance on how to determine elastic electricity inputs:

- Elastic input:
  - Only the renewable electricity that is additional "meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy", i.e. additional to what would have been consumed in the power sector;
  - Renewable electricity that would otherwise be curtailed "when both the electricity generation and the fuel production plants are located on the same side in respect of the congestion" on the transmission grid can also be considered to be additional.
- Rigid input: If either grid electricity or renewable electricity is diverted from other uses in the power sector and its renewable properties have already been claimed in the power sector.

To meet the 70% GHG savings requirement, it is clear that a large share of the inputs in the RFNBO production will need to come from zero-emission renewable energy sources. **Only the elastic inputs of truly additional renewable electricity sources should be considered as zero emissions.**

For the rigid inputs, the non-additional electricity input to electrolysers should be considered to have the carbon intensity of the national average GHG intensity of consumed electricity, i.e. the carbon intensity of the electricity as it is delivered to the electrolyser. In other words, this should include not only the emissions at the level of the power station, but also include upstream emissions to supply the fuel and the transmission losses.

For RFNBOs, the main challenge will be how to distinguish between additional and non-additional renewable energy. The RED II is already clear that electricity obtained from direct connection to a new[3] and non-grid connected installation generating renewable electricity can be counted as fully renewable. Creating the right regulatory framework for the additional renewable electricity that is supplied via the grid will be key to support RFNBO

[2] Our comments focus on the broad range of electrofuels - produced via electrolysis, supplied by renewable electricity sources - within the category of the RFNBOs. However, the GHG methodology should ensure to not exclude other sources of renewable energy in the form of heat: For example, concentrated solar power can be used to produce a high-temperature thermochemical reaction, which can be used in RFNBO production.

[3] An RFNBO installation is new, when it "comes into operation after, or at the same time as, the installation producing the renewable liquid and gaseous transport fuels of non-biological origin".

production. Why? The higher the operating hours / load factor for the electrolyser, the more cost-competitive the production cost of renewables-based hydrogen can be. Sourcing renewable electricity via the grid may, however, be an important option to enable high number of operating hours for electrolysers situated in less favourable conditions for the production of renewable electricity. A recent T&E report on decarbonising freight showed that 2800 full-load hours are considered realistic in order to provide for a load factor of 30 percent for an electrolysis plant in the megawatt range. The resulting hydrogen cost level ranges between 2.33 to 4.00/kgH2, excluding transport and distribution costs. Today, offshore wind facilities in the North Sea can reach more than 3,600 full-load hours on average and would therefore be suitable for the production of electricity-based fuels, if their total electricity production was devoted to it.[4]

T&E is currently considering several options for demonstrating additionality: Power purchase agreements (PPAs) between efuel producers and renewable electricity providers and/or a new system of guarantees of origin + (GO+) for new and unsupported renewable electricity generation.[5] We will contribute to this discussion during the next stakeholder meeting with the European Commission and its consultants in the fall.

3. Accounting for carbon sources

T&E remains committed to the principle that RFNBOs should use CO2 captured from the air as the carbon-based feedstock. Direct Air Capture of CO2 is the only source of carbon that is fully compatible with the EU's stated target of becoming a net-zero economy by 2050.[6] Together with other NGOs, we also defended this position during the negotiations on RED II.[7] Unfortunately, the final text of the RED II does not address how the carbon for carbon-based RFNBOs should be sourced.

In line with the lack of guidance on the source of carbon used for carbon-based RFNBOs in the RED II, the proposed GHG methodology does not distinguish between the different sources of carbon that can be used in the production of carbon-based synthetic hydrocarbons. The CO2 used in the production of RFNBOs can come from three sources:

1. CO2 from the atmosphere,
2. CO2 from biogenic origin,
3. CO2 of fossil carbon origin.

Below, we outline our position with regard to these three sources.

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[4] T&E (2020) How to decarbonise the French freight sector by 2050? Retrieved from https://www.transportenvironment.org/sites/te/files/publications/2020_05_TE_how_to_decarbonise_the_french_freight_sector_by_2050_final.pdf

[5] Oeko-Institut (2017) Improving the accounting of renewable electricity in transport within the new EU Renewable Energy Directive. Retrieved from https://www.transportenvironment.org/publications/how-make-renewable-energy-directive-red-ii-work-renewable-electricity-transport

[6] T&E (2017) How to incentivise renewable aviation fuels through the RED. Retrieved from https://www.transportenvironment.org/sites/te/files/publications/2017_09_Aviation_REDII_final.pdf

[7] Bellona (2018) CCU fuels in the recast Renewable Energy Directive: Letter to Negotiators. Retrieved from https://bellona.org/publication/ccu-fuels-in-the-recast-renewable-energy-directive-letter-to-negotiators

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CO2 from the atmosphere

The proposed GHG methodology does not offer any specific support for circular sources of carbon, as obtained via Direct Air Capture. The main reasons presented by the JRC to not make distinctions between different sources of carbon are the higher energy consumption involved in capturing carbon from the atmosphere than from concentrated point sources and the fact that there is no shortage of industrial sources of CO2 for the foreseeable future.

T&E sees two risks in this approach:

1. There is a risk that the CCU from fossil sources will potentially lead to lock-in of fossil sources of CO2. Industries will invest in CCU units nearby their operations: This will be long-lasting infrastructure that will complicate the transition from fossil to clean, circular sources of carbon.
2. The major cost difference between CCU and DAC is not addressed and will result in a potential delay in DAC development. DAC cost estimates vary widely: EUR 145/tonne until 2030, whereas others put the current cost around EUR 270/tonne, declining to EUR 165/tonne in 2030. The costs of CCU are estimated to be around EUR 30/tonne.[8] Not differentiating between carbon and circular sources will not result in the necessary impetus to rapidly close the gap. The funding provided for DAC by the Innovation Fund is unlikely to match the amount that private sector funding can invest in the DAC technology over the next 10 years.[9] But that will require a dedicated policy push.

The GHG methodology cannot remain agnostic about this necessary transition from CCU to DAC.

To counter the above-mentioned risks, we propose that the GHG methodology confirms the principle that investments in fossil carbon from industrial point sources needs to be phased out by 2025. Investments made in CCU from industrial point sources before 2025 could be grandfathered in, i.e. the installations producing CCU fuels from point sources and constructed before 2025 would be allowed to be used as an eligible source of carbon under RED II. This is an important signal to investors that in the mid-term only circular sources of carbon will be acceptable in the production of RFNBOs. We call on the Commission to develop a better understanding of how the transition of carbon to circular sources of carbon can happen and the wider impacts of that transition: What will be the future demand for carbon to be used in the production of carbon-based fuels? What is the timing of the deployment of DAC and its impacts (number and location of units, energy consumption involved, etc.)? To determine the pace and speed of the phase-out, an analysis of the potential demand for carbon in RFNBO production and the fossil

[8] Agora Energiewende and Agora Verkehrswende (2018) The Future Cost of Electricity-Based Synthetic Fuel. Retrieved from https://www.agora-energiewende.de/fileadmin2/Projekte/2017/SynKost_2050/Agora_SynKost_Study_EN_WEB.pdf P. 30 and OKO (2020, forthcoming) E-fuels versus DACCS.
See also Fasihi et al. (2019) Techno-economic assessment of CO 2 direct air capture plants in Journal of Cleaner Production (Vol. 224). Retrieved from https://www.sciencedirect.com/science/article/pii/S0959652619307772#sec4.3.1

[9] Depending on the price of the ETS allowances, the Innovation Fund will have about EUR 10 billion available to invest in innovative low-carbon technologies during the period 2020-2030. This money will be invested in CCU, but also in CCS, innovative renewable energy, energy storage and decarbonisation of energy-intensive industries. The level of funding for DAC is uncertain.

carbon supply from industrial sources is currently lacking and is needed to plan ahead for the longer term.

RFNBO producers should also be required to set a minimum share of DAC from the start. This level of DAC can be initially set at a very low level and gradually increased over time and eventually reach a 100% share in 2050. A growing demand for and the resulting deployment of DAC will help close the cost gap between DAC and CCU and build up the relevant EU carbon removal capacity for net-negative emissions in the post-2050 period.

To determine the carbon footprint of CO2 from the atmosphere, the GHG methodology should include both the emissions reductions delivered by DAC, while also accounting for the energy use involved in the DAC process.

CO2 of fossil carbon origin

The current Renewable Energy Directive does not prescribe a certain type of CO2 source and leaves the possibility to account for fuels produced with CO2 of fossil origin. Our starting point is that the GHG methodology should not undermine or delay the implementation of ambitious measures to decarbonise industries covered by the ETS and that there should be a robust framework in place to avoid the double counting of emissions reductions. The CO2 captured from industrial point sources covered by the ETS and sold to RFNBO suppliers should still require the industrial actor to pay for allowances under the ETS. The CO2 used in RFNBOs will be released shortly after the use, just like it would be from the combustion of a fuel. Currently, the ETS only recognises permanently stored CO2 as an emission reduction. This is a clear rule and a clear separation of ETS and non-ETS should be maintained.[10] Other organisations like Bellona have warned in the past that "including non-permanent storage methods of CCU into the ETS could institutionalise 'CO2 laundering'. Industrial actors covered by the ETS could pass on captured CO2, for instance in the form of fuel, to another actor outside the ETS".[11] The proposed GHG methodology avoids that risk by recognizing that CCU in the context of RFNBO is not a form of storage, but rather a delayed release of carbon in the atmosphere.

The GHG methodology should also distinguish between different sources of fossil carbon. Not all ETS sectors should be allowed to sell their carbon to RFNBO producers. There should be no role for the use of CCU in the EU energy sector, the generation of power and heat. Why? There are many technological options to decarbonise the energy sector more rapidly, including energy efficiency, renewable energy, demand side flexibility, etc. The use of fossil fuels in the power and heat sector must be phased-out extremely rapidly and enabling CCU risks delaying this necessary phase-out. Hence, industries outside the energy sector *sensu stricto* like pulp and paper, steel and iron and cement are better placed as short to medium-term suppliers of fossil carbon.

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[10] If CO2 use in RFNBO production would be treated similarly as permanent storage under the ETS, industrial emitters could opt to capture the CO2 and sell it to other industrial consumers of CO2. Selling CO2 to non-ETS sectors would be cheaper than investing in mitigation strategies. This situation could occur, especially if ETS prices would rise significantly.

[11] Bellona (2016) CCU in the EU ETS: risk of CO2 laundering preventing a permanent CO2 solution. Retrieved from https://network.bellona.org/content/uploads/sites/3/2016/10/BellonaBrief_CCU-in-the-EU-ETS-risk-of-CO2-laundering-preventing-a-permanent-CO2-solution-October-2016-2.pdf

In that context, if the GHG methodology is applied to point source of CO_2 should include at minimum the upstream emissions and emissions from capturing and using carbon.

CO2 from biogenic origin

CO_2 from bioenergy industries should not be allowed, because of the negative climate and environmental impacts associated with the use of biomass, especially land-based, for energy purposes. There could be an exception for plants which are already using advanced biomass (waste & residues) feedstocks sourced sustainably. However, we do not support the use of biogenic CO_2 from new facilities; given the limited feedstock available.

The RED II doesn't exclude biogenic sources of CO_2. In case a biogenic CO_2 source is used, the GHG methodology should ensure that bio-energy with carbon capture and storage (BECCS) should not be double counted in terms of their emissions reductions: For example, a bioethanol fermentation plant that captures its CO_2 and counts its CO_2 savings under the ETS, while also counting the avoided emissions of using low-carbon renewable fuels - compared to a fossil fuel comparator - in the transport sector.

To determine the carbon footprint of biogenic CO_2, the GHG methodology should at least account for the added emissions due the effects of Indirect Land Use Changes and indirect displacement effects in other sectors of the economy.

I remain available to respond to any questions you may have on the above-mentioned points.

Sincerely,

Geert De Cock
Electricity & Energy Manager
Transport & Environment