PUBLIC CONSULTATION RESPONSE - October 2024

T&E position on low-carbon fuels

Summary

T&E welcomes the opportunity to respond to the public consultation on a "Methodology to determine the greenhouse gas (GHG) emission savings of low-carbon fuels"

T&E has the following key asks:

1. T&E asks for **a more conservative default value for upstream methane emissions**. The data used to underpin the default values should be shared and updated in light of the significant shifts in the mix of EU gas suppliers. The default values should reflect the higher level of fugitive methane emissions of suppliers gaining in importance (US in particular). As the methane intensity methodology will only apply to new contracts concluded from August 2024, there is a concern that the default value will remain widely used for longer.
2. Midstream emissions from transporting the fossil gas feedstock must be taken into account. T&E asks for **clarity whether and how the midstream emissions will be accounted for**, as these can be significant - especially in the case of LNG. A default value for upstream emissions should be introduced.
3. The low-carbon fuels delegated act should **use the GWP20 for fossil gas**.
4. **Fugitive hydrogen must be included in the low-carbon fuels GHG methodology.** If not, hydrogen leakage must at least be part of the 2028 review.
5. The list of **carbon sources should be consistent for RFNBOs and low-carbon fuels**. Hence, the 2041 deadline for phasing out the eligibility of fossil carbon should be maintained. However, **more incentives and support are needed to scale up non-biogenic sources of carbon**, particularly Direct Air Capture (DAC), ahead of the 2041 phase-out date for fossil carbon.
6. To ensure climate neutrality, the European Commission should assess the merits of **a higher GHG savings threshold for low-carbon fuels in its mid-2028 review** as well as the principle of **non-additionality of fossil gas production** used to produce low-carbon fuels.
7. The production of RFNBOs and low-carbon hydrogen should **not undermine or slow down the decarbonisation of the grid**.

Introduction

Our comments focus mainly on blue hydrogen, i.e. the use of fossil gas to produce low-carbon hydrogen by means of Steam Methane Reforming (SMR) combined with Carbon Capture and Storage (CCS). T&E finds that the low-carbon status of blue hydrogen depends on unrealistic assumptions about emissions throughout its supply chain: low upstream and midstream emissions, the high capture rate of CCS and its supposedly low energy demand. These issues are unlikely to be resolved by 2030. At best, blue hydrogen is a low-carbon fuel rather than a zero-carbon solution.Therefore, blue hydrogen is not a realistic long-term solution to achieving full decarbonisation.

For the decarbonisation of most of the aviation and shipping traffic, where electrification is not feasible, the EU should prioritize the use of RFNBOs (Renewable Fuels of Non-Biological Origin aka green hydrogen and derived e-fuels). Producing RFNBOs with additional wind and solar has several advantages: These solutions are more scalable - while minimizing environmental impacts - to meet the surge in demand for RFNBOs by 2050 (unlike biofuels and fossil fuels). At the same time, investing in RFNBOs enables the EU to move away from - mainly imported - fossil fuels. And it builds on the strengths of European industry champions in sectors like wind, electrolysers, synthesis processes, etc. Last but not least, the sustainability rules on RFNBO will deliver on the promise of truly zero-carbon fuels, without many of the uncertainties involved in blue hydrogen. This is why European and national regulatory and financial support should be prioritised to supporting the supply and demand for RFNBOs (in the transport, for aviation and shipping).

1. Upstream emissions

Key ask: T&E asks for a more conservative default value for upstream methane emissions. The data used to underpin the default values should be shared and updated in light of the significant shifts in the mix of EU gas suppliers. The default values should reflect the higher level of fugitive methane emissions of suppliers gaining in importance (US in particular). As the methane intensity methodology will only apply to new contracts concluded from August 2024, there is a concern that the default value will remain widely used for longer.

In the RFNBO delegated act, the Commission used 9.7 gCO_{2e}/MJ as a default value - supplied by the Joint Research Centre - to assess the carbon footprint of fossil gas. This value corresponds to an upstream methane leakage rate of ~1%. In this proposal, the Commission acknowledges that the default value for the upstream emissions of fossil gas needs to be updated. The proposal increases the default value to 10.45 gCO_{2e}/MJ, assuming that the fugitive methane emissions correspond to 5 gCO_{2e}/MJ. This new default value corresponds to a 1.4% leakage rate.

However, this new value of 10.45 gCO_{2e}/MJ is insufficient to reflect the changing mix of gas suppliers (more LNG, more suppliers located further away from the EU, more reliance on unconventional/shale gas in the US) and the growing awareness about the considerable impact and size of the fugitive methane challenge.

T&E member Deutsche Umwelthilfe commissioned a literature review on fugitive methane: The reviewed studies on the topic show that leakage at many points in the supply chain is much higher than previously thought. The benchmark is now about 3% methane leakage. Using the GWP20 of fossil methane (see point # 3), this makes the climate damage caused by methane emissions along the natural gas supply chain just as high or even higher than the climate damage caused by the combustion of natural gas at the end consumer.

A ‘real world’ assessment of the carbon footprint of low-carbon hydrogen and fuels will have to await the implementation of a methane transparency database as proposed under the EU Methane Regulation 2024/1787. The data to populate this database should become available from 2028, after the adoption of the methane intensity methodology (required by Article 29.4 of the EU Methane Regulation). While we await these ‘real world’ values, T&E advocates that a higher default value - reflecting the benchmark of a 3% leakage rate - should be included, for 3 reasons.

1. The changing gas supply mix of the EU since the Russian invasion of Ukraine - with more LNG and especially more LNG from unconventional shale gas production in the US - needs to be reflected in the default value. The US now accounts for 50% of all LNG imports and LNG accounts for 41% of all imported gas. If the EC sticks to 10.45 gCO_{2e}/MJ as default value, this would be outdated and not reflecting the real carbon footprint of current and future gas supplies to Europe. In the absence of measurements based on the methane intensity methodology after 2027, even the default value +40% sits below the default GREET values used by US public authorities. It is well documented that the production of American shale gas has much higher upstream emissions, compared to e.g. domestic or Norwegian pipeline gas. A recent peer-reviewed study based on 1 million measurements in the US shows that upstream emissions in the US are actually closer to 3%. Since the start of unconventional gas development (fracking for shale gas) around 2010, the carbon footprint of US gas production has received more scrutiny than other gas suppliers. Hence, it makes sense to use the US values as a benchmark for other gas suppliers as well. As accurate empirical data from satellites become available, national/regional default values to distinguish between different suppliers.
2. The advantage of a higher default value for methane emission is that it will incentivise oil and gas companies to already start minimizing their upstream methane emissions before the methane transparency database becomes operational, deterring gas suppliers with a high upstream carbon footprint to produce low-carbon hydrogen and fuels. By rewarding those operators that use Best Available Technologies (BAT) and deliver well below upstream leakage rates, the EU can help reduce methane emissions in the energy sector.
3. A high default value - reflecting the gas industry’s past poor track record and the latest evidence - will also push producers of e.g. ‘blue’ hydrogen to achieve higher carbon capture rates. To qualify as low-carbon and meet the -70% GHG savings threshold, operators of CCS facilities should achieve higher carbon capture rates than has been typical for CCS projects until now (most operational projects have been in the 60% capture range). A higher default value for upstream methane will give an advantage to those companies that invest in advanced reforming technologies (e.g. autothermal reforming) that achieve the higher 90+% capture rates that the industry has promoted as technically feasible.

The Commission’s proposal to increase - from August 2025 - the default value for upstream emissions by 40% - when gas suppliers are unable/unwilling to use the EU’s carbon intensity methodology to report on their fugitive methane emissions - is insufficient. This entails an increase from 10.45 gCO2e/MJ to ~12.45g gCO2e/MJ by increasing the default value for upstream fugitive methane by 40% from 5 gCO2e/MJ to 7 gCO2e/MJ. This default value + 40% corresponds to a just below 2% (1.92%) upstream leakage. This is well below the 3% that is cited in the literature on the topic.

Given the long-term nature of gas supply contracts, T&E is concerned that the overly optimistic default value for fugitive methane will continue to be used, even after the methane intensity methodology comes into play. From the end of 2027, producers in the EU as well as importers will have to start reporting their fugitive methane emissions on the basis of the methane intensity methodology for fossil gas placed on the EU market. However, this requirement only applies to gas supply contracts concluded or renewed on or after 4 August 2024 produced outside the Union. For contracts concluded before 4 August 2024 for the supply of gas produced outside the Union, importers only need to undertake “all reasonable efforts” to ensure that “equivalent” MRV measures are put in place. Given the nature of gas supply agreements, long-term off take agreements tend to be quite common for terms often exceeding 20, 25, or even 30 years. Even though LNG spot markets have emerged, the concerns about the security of supply of gas since the start of the war in Ukraine “has re-focused buyers towards long-term contracts”.

2. Midstream emissions

Key ask: Midstream emissions from transporting the fossil gas feedstock must be taken into account. T&E asks for clarity whether and how the midstream emissions will be accounted for, as these can be significant - especially in the case of LNG. A default value for upstream emissions should be introduced.

The Commission proposal does not elaborate how the midstream emissions will be accounted for. Table B in the proposal labels midstream emissions as ‘not applicable’. T&E calls on the European Commission to clarify how midstream emissions will be accounted for. The EU Methane Regulation 2024/1787 includes midstream emissions in its scope:

- *natural gas transmission and distribution, excluding metering systems at final consumption points and the parts of service lines between the distribution network and the metering system located on the property of final customers, as well as underground storage and operations in LNG facilities; and*

Especially for LNG, the (carbon footprint of) the energy used for the liquefaction of fossil gas is significant if the fossil gas is used as a feedstock for low-carbon ‘blue’ hydrogen. It is important that LNG midstream emissions (liquefaction, LNG carrier transport and LNG bunkering) are fully accounted for in the calculation of the carbon footprint of low carbon fuels. The forthcoming delegated act developing a Methane Intensity Methodology will need to assess in a comprehensive manner the parts of the LNG supply chain: Not only where fugitive methane emissions can occur, but also the carbon footprint of the energy used in e.g. the liquefaction of the fossil gas feedstock.

The Well-to-Tank default value for LNG in the FuelEU regulation (Annex II - Default emission factors) refers to a default value of 18.5 gCO_{2e}/MJ. This confirms that the carbon footprint of LNG is very significant: Deducting the previous upstream default value of 9.7 gCO_{2e}/MJ from the FuelEU WtT value for LNG gives 8.8 g gCO_{2e}/MJ for midstream emissions. A literature review of the carbon footprint of LNG (to be published in a forthcoming report by T&E) shows that 8.8 gCO_{2e}/MJ would be a rather optimistic default value for LNG. This literature review shows that the midstream carbon footprint of major LNG suppliers to Europe is likely to be much higher, ~ 12 g gCO_{2e}/MJ. This latter value is also aligned with recent peer-reviewed research on the carbon footprint of LNG exports from the US. Fugitive methane is also linked to transporting LNG by ships: Depending on sailing speed and the onboard engine technology (4 stroke vs 2 stroke engines vs steam turbines), shipping emissions of LNG cargo can be significant.

For T&E, setting a default value for midstream emission makes sense, both for transporting gas via LNG tankers and pipelines. This could be expressed in terms of average emission values per 1000 km. Such a default value should be set sufficiently high to encourage gas suppliers to minimize their midstream emissions (e.g. using low-carbon/renewable energy in the liquefaction process, using energy-efficient tankers, etc.).

The European Commission should clarify why default values for upstream emissions are proposed in the delegated act on low-carbon, while nothing is proposed for midstream emissions. Even though both are included in scope of the EU Methane Regulation. Given that the EU Methane Regulation's requirement to report on fugitive methane emissions will only apply to gas supply contracts concluded or renewed on or after 4 August 2024, it is likely that the default value for upstream methane emissions will remain relevant for years - possibly decades - to come. This is why setting midstream fugitive methane emissions default values - expressed in terms of average emission values per 1000 kms, for pipelines and LNG - will also be crucial. The table in the proposed Annex should be adapted to also include default values for midstream emissions, both for pipeline gas and LNG. See revised table below.

Fuel	Upstream GHG emissions gCO_{2e}/MJ			Midstream GHG emissions gCO_{2e}/MJ				Combustion GHG emissions gCO_{2e}/MJ
				Pipeline average emission values per 1000 kms		LNG average emission values per 1000 kms		
	CO2	CH4	N2O	CO2	CH4	CO2	CH4	
Natural gas	5.4	5	0.05	x	x	x	x	56.2

3. Assess the immediate climate benefits of low-carbon fuels, using the GWP20 of fossil methane.

Key ask: The low-carbon fuels delegated act should use the GWP20 for fossil gas.

The choice of 100 years over 20 years Global Warming Potential value for fossil gas is questionable. Unless low-carbon fuels immediately help to reduce emissions and contribute to the EU's 2050 objective of climate neutrality, their added value is questionable. T&E calls on the Commission to include the GWP20 values for gas that were included in AR6, the sixth Assessment Report of the IPCC. The GWP20 for fossil gas is particularly relevant to assess the climate benefits of fossil gas as a feedstock for low-carbon fuels.

Global Warming Potentials from the Fourth, Fifth, and Sixth Assessment Reports (IPCC)

		CO_2		CH_4		N_2O	
		GWP_{20}	GWP_{100}	GWP_{20}	GWP_{100}	GWP_{20}	GWP_{100}
AR4		1	1	**72.0**	25.0	289	298
AR5	No CC fb	1	1	**84.0**	28.0	264	265
	W. CC fb	1	1	**86.0**	34.0	268	298
AR6	Fossil	1	1	**82.5**	29.8	273	273
	Non-fossil	1	1	79.7	27.0	273	273

The Commission's choice to continue using the GWP100 value over the GWP20 value for methane results in underestimating the warming effects of methane over a shorter time frame.
For short-lived climate pollutants, 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. Methane 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, fossil methane is 82.5 times more polluting than carbon dioxide over a 20-year time, but from a 100-year perspective it is 29.8 times more polluting than CO_2. 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.

4. Hydrogen leakage

Key ask: Fugitive hydrogen must be included in the low-carbon fuels GHG methodology. If not, hydrogen leakage must at least be part of the 2028 review.

The Article 9.5 of the Gas Directive 2024/1788 instructs the European Commission to include "the treatment of emissions due to the leakage of hydrogen" in the methodology for assessing GHG savings from low-carbon fuels. T&E refers to the Environmental Defence Fund's submission to the public consultation for more details.

The latest science suggests that hydrogen emissions have a GWP100 of ~12 greater than CO_2. If these emissions are not appropriately considered in the GHG methodology, the climate benefits of low-carbon fuels are likely to be overstated. The claim in recital 5 of the delegated act that the GWP of hydrogen "has not yet been determined with the level of precision required to be included in the methodology for calculating greenhouse gas emissions" is not compatible with the scientific publications on this topic. The current science allows the introduction of a default value to include the GWP of hydrogen in the assessment of whether low-carbon fuels meet the 70% GHG savings threshold, as a stepping stone towards actual measurements. The introduction of such a default value will not only encourage producers to start measuring and reporting on hydrogen, but also to minimize hydrogen leakage.

At the very least, hydrogen leakage should be mentioned in the review clause in article 3 of the delegated act on how "to source low carbon electricity from nuclear power plants". The Commission should develop a proposal on how to include hydrogen leakage by mid-2028. Not setting a deadline for addressing hydrogen leakage is not aligned with the letter and spirit of article 9.5 of the Gas Directive.

5. List of eligible carbon sources

Key ask: The list of carbon sources should be consistent for RFNBOs and low-carbon fuels. Hence, the 2041 deadline for phasing out the eligibility of fossil carbon should be maintained. However, more incentives and support are needed to scale up non-biogenic sources of carbon, particularly Direct Air Capture (DAC), ahead of the 2041 phase-out date for fossil carbon.

In line with the text and spirit of Article 9.5 of the Gas Directive 2024/1787, T&E insists that the list of eligible carbon sources that can be used to produce low-carbon fuels “shall be consistent” with the delegated act on the RFNBO GHG methodology. This includes in particular the 2041 deadline for the use of fossil carbon from ETS installations for the production of low-carbon fuels and RFNBOs.

T&E supports this phase-out date, as it is an important signal to producers of low-carbon fuels and RFNBOs to think long-term about where to source sustainable carbon from. T&E already showed how the carbon demand for the production of RFNBO and low-carbon fuels will start to outstrip the biogenic carbon supply shortly after 2030. Without a longer-term reliance on fossil carbon and with biogenic carbon in short supply, atmospheric carbon by means of DAC will be essential if aviation is to decarbonise with the sector alone demanding 99-313 $MtCO_2$ by 2050.

However, it is clear that the DAC technology is not scaling up sufficiently quickly to keep up with the demand for sustainable carbon (of which RFNBO and low-carbon fuels is only part). There are some DAC investments happening, especially in the United States as a result of the IRA 45Q production tax credit. The 45Q tax credit offers USD 180 per tonne of CO_2 permanently stored using DAC and USD 130 per tonne for used CO_2 sourced using DAC. Tech companies like Google are taking advantage of the IRA tax credit to conclude a long-term off take agreement for DAC.

While the American support for and investments in DAC will ultimately also benefit fuel producers in the EU, there is no equivalent measure or incentives in Europe to scale up DAC. In the context of ReFuelEU negotiations, T&E and the Negative Emissions Platform advocated for a share of DAC to be mandated as part of ReFuelEU within the synthetic aviation fuel sub-target: 10% of the carbon feedstock in 2030 should come from DAC, 20% in 2035, 40% in 2040, 80% in 2045 and 100% by 2050. Without such initiatives to stimulate demand, it is unlikely that there will be sufficient sustainable carbon supply in Europe.

The previous Commission already identified DAC for CCU in ‘synthetic fuels’ in its Industrial Carbon Management Strategy as a key pillar: “Whilst initially using all types of CO2, over time a strategic focus of utilisation value chains on capturing biogenic or atmospheric CO2 will yield higher climate benefit.”. The plans of the next Commission for a Single Market for CO2, carbon removals, CO2 transport and storage infrastructure, increasing the uptake of carbon capture and utilisation and carbon capture and storage will create some of the necessary framework conditions to enable DAC, but will not be sufficient on its own .

6. Ensuring that low-carbon fuels are aligned with climate neutrality and no new gas capacity

Key ask: To ensure climate neutrality, the European Commission should assess the merits of a higher GHG savings threshold for low-carbon fuels in its mid-2028 review as well as the principle of non-additionality of fossil gas production used to produce low-carbon fuels.

Recital 13 of the Gas Directive 2024/1787 is clear that the threshold for greenhouse gas emission reductions for low-carbon hydrogen and synthetic gaseous fuels “should become more stringent for hydrogen produced in installations starting operations from 1 January 2031 to take into account technological developments and better stimulate the dynamic progress towards the reduction of greenhouse gas emissions from hydrogen production”. This is important to ensure that the longer-term use of low-carbon fuels is aligned with the EU's binding target of climate neutrality by 2050. For example, the EU could set a dynamically decreasing maximum greenhouse gas threshold for low-carbon fuels, starting with 3.38 $kgCO_{2e}/kgH_2$ (the current threshold) to reach 3 kg (referred to in the EU taxonomy) by 2030, 2 kg by 2040 and 1 kg by 2050.

A second way of ensuring that low-carbon fuels are aligned with climate neutrality is to introduce a clause requiring that low-carbon hydrogen made from fossil fuels is only made from existing (non-additional) gas production capacity. Low-carbon hydrogen must not deepen Europe’s fossil fuel dependency. It must align with the phase-down trajectory outlined in the EU’s 2040 climate targets impact assessment.

7. The use of low-carbon electricity to produce electrolytic hydrogen should not have a negative impact on the carbon intensity of grid electricity

Key ask: The production of RFNBOs and low-carbon hydrogen should not undermine or slow down the decarbonisation of the grid.

The electrification of the road transport sector is central to the decarbonisation of the transport sector. Switching from a vehicle with an internal combustion engine to an electric vehicle always reduces emissions, even if the grid is not decarbonised. However, the emission savings from electrifying road transport can be much greater if more renewable and low-carbon electricity is used to charge cars, vans, buses and trucks. The production of RFNBOs and low-carbon hydrogen should not undermine or slow down the decarbonisation of the grid.

Connecting many new multi-MW scale electrolysers to the grid will increase demand for electricity generation. If this additional generation is supplied by fossil fuel generation, the carbon intensity of the grid will increase. If the electrolyser contracts with an existing supply of low-carbon electricity, which is already supplying the grid, the effect will be the same if the demand which has been displaced by the electrolyser is met via fossil fuel generation. Only if the additional demand on the grid is met by additional low-carbon or renewable generation will a higher grid electricity carbon intensity be avoided.

The delegated act proposal already allows bidding zones with low-carbon electricity to use the average carbon intensity of the grid, on the condition that the 70% GHG savings threshold is reached. There is currently no legal or technical mechanism in place to ensure that a supply of low-carbon electricity (e.g. a PPA with a nuclear power plant) will not lead to more fossil-fuel power generation in the bidding zone where the electrolyser is located as well as in the interconnected bidding zones that rely on the low-carbon power supply. Bringing more gas-fired power plants online will not only lead to increased emissions; Changing the merit order in electricity markets may also position gas power plants as the marginal unit and increase electricity prices for households and businesses as a result.

Conclusions

The EU has set stringent rules for the production of RFNBOs. Even if these are not perfect, T&E has been a staunch supporter of these rules and has not hesitated to advocate for more ambition on RFNBOs (RFNBO mandates for aviation and shipping, European Hydrogen Bank auctions, etc). At the very least, equally stringent rules on low-carbon fuels should be set, to ensure that their negative climate impacts are minimized. Weak rules would risk undoing the ongoing work to build a green hydrogen industry in Europe, which should be an essential element of the Clean Industrial Deal proposed by Commission President von der Leyen in her Political Guidelines.

Further information

Geert Decock

Electricity & Energy Manager

Transport & Environment

geert.dc@transportenvironment.org

Mobile: +32(0)484 629 491