

**Delegated Act on Methodology for determining GHG emission savings from RFNBO/RCF (Annex I)**  
**FuelsEurope’s Case Studies for RFNBO and RCF production**

**Identification of relevant areas subject to multiple interpretation and/or leading to unintended consequences**

**Question & Answers (FuelsEurope’s interpretation)**

**FuelsEurope**, the European Association representing the refining industry, strongly supports the EU objective of net climate neutrality in 2050 and the circular economy, and stands ready to support policy makers to reach such goals. The refining industry is actually transforming and sustainable Low Carbon Liquid Fuels, including both RFNBOs and RCFs, are the centrepiece of this transition (strategy described in the [Vision 2050](#) and [CleanFuelsForAll](#) publications). In this context, we warmly welcome the initiative of the European Commission to propose a detailed methodology with the required criteria to provide a stable framework to rule the production of these RFNBO/RCF in the close future.

In preparation for the certification of RFNBO/RCF cases, a core group of technical experts from different member companies have assessed the implications of the methodology described in the Delegated Act and identify some key relevant areas that, in the absence of harmonisation across certification bodies, would likely lead to a non-homogeneous and multiple interpretation, leaving to the auditors the final decision on aspects that would be key to determine the business case for the industrial production of these fuels. Now that the Delegated Act is about to be adopted, FuelsEurope would like to share our main concerns and eventual proposal for interpretation (in no contradiction with the text included in the relevant Delegated Acts and Renewable Energy Directive texts) as the result of the technical work internally conducted.

In this regard, we would kindly invite the European Commission to consider the implications of the assessed case studies and the proposals presented by FuelsEurope and eventually **add, at least at certification level, some clarification on the relevant aspect identified**, ideally as part of the system documents likely to be approved in the short term, to ensure an even interpretation across Europe, avoiding any potential market distortion from multiple interpretations by different auditors in the non-that-far-future.

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## SUMMARY

### 1. Multiple electricity sources as inputs to an electrolyser.

#### 1.1. Link between DA for production of renewable Hydrogen, DA GHG methodology RFNBO / RCF & RED-T

Case Study: Electrolyser with multiple sources of electricity as simultaneous inputs: fully renewable electricity from wind/solar (covered by PPA and complying with additionality, temporal and geographical correlation) and electricity from the grid (country mix).

The issue: Absence of a clear interpretation on how much electricity from the input could qualify as RFNBO as compliance options against Renewable Energy Directive (RED) targets. Question mark about whether PPA are needed to account for the renewable share of electricity in the grid.

Interpretation: The amount of renewable electricity and corresponding hydrogen production that can qualify as RFNBO in a given time interval is the **sum** of the fraction complying with the DA “fully renewability” criteria plus, for the fraction that does not qualify as fully renewable, the share of renewable energy in the electricity mix according to RED II Art. 27(3). Several considerations on the electricity sourced from the grid arise.

#### 1.2. Selection of the temporal interval for GHG calculations

Different considerations regarding the “time interval” (“DA GHG Methodology *up to 1 month*”) and “temporal correlation” (DA “additionality” 1h after 2030) are presented in the two RFNBO related Delegated Acts which could lead to multiple interpretations. Questions arise regarding whether (and if so, how) a one-month period be allowed for GHG emission calculations beyond 2030.

### 2. Multiple co-products: Implications derived from choice of allocation method. The « vicious circle »

Case Study: Electrolyser sourced by both fully renewable electricity and electricity from the mix.

The issue: A strict interpretation of DA GHG methodology may lead to severe unintended consequences derived from the application of economic allocation. A “vicious circle” will likely be created, as described in *Case Study 2* of this paper where a scenario involving O<sub>2</sub> as a commercialised co-product is presented. As O<sub>2</sub> has no energy content, energy allocation will apply to H<sub>2</sub> RFNBO and low carbon H<sub>2</sub> fractions, resulting in two different carbon intensity values for each of them, higher for the H<sub>2</sub> RFNBO fraction, compromising eligibility of H<sub>2</sub> RFNBO artificially and creating instability (fluctuations) in their market value.

Interpretation proposed: **Two-step allocation approach** between energy and non-energy content fractions, consistently with the wording included in the DA GHG methodology, is proposed leading to the same carbon intensity for both RFNBO H<sub>2</sub> and low carbon H<sub>2</sub>.

### 3. Mix of inputs (Exception): Co-processing. Implications for the calculation of both share of each type of fuel in output and associated carbon intensities

Case Study: As an illustrative example, a Syngas manufacturing and Fischer-Tropsch (FT) conversion unit is presented where a different mix of inputs including fossil fuels are co-processed, falling under the exception laid down in article A.1 (Annex) and leading to a different carbon intensity of the fractions in the output estimated [...] *on a proportional basis of the energetic value of inputs [...]*.

The issue: The co-processing of different renewable, recycled, biogenic and/or fossil feedstocks via syngas and Fischer-Tropsch (FT) pathway poses a number of questions regarding whether individual carbon intensity values can be estimated for each fraction of the outcome, the differences between the *feedstock* and *input* concept in a multi-step conversion process (i.e. process consisting of multiple conversion units) and the implications in terms of the different Lower Heating value when either a *feedstock* or an *input* based allocation is followed, the actual estimate of the carbon intensity or the possibility to apply free allocation of the inputs to the different co-products (in terms of type of input). Beyond the DA on GHG methodology, the clear recognition of the qualification of the fractions in the outcome as different type of fuels based on the inputs is deemed relevant also in the context of the ReFuelEU Aviation regulation. The key question in this example is **whether allocation on LHV basis should apply to (dry) feedstocks or to syngas stream.**<sup>1</sup>

<sup>1</sup> Technical clarification: Syngas is a mixture of carbon monoxide and hydrogen. Feedstocks, such as biomass, renewable power, CO<sub>2</sub>, water, waste, fossil, are converted into carbon monoxide and hydrogen (also called syngas); next, carbon monoxide and hydrogen are combined in an FT unit to make FT wax, which is next converted in a hydroprocessing unit (with extra addition of renewable hydrogen, as needed) into final FT products (fuels), like kerosene.

#### 4. Biofuel production and RFNBO/RCF fuels. Link with DA Co-processing

Case Study: Syngas manufacturing and Fischer-Tropsch conversion unit where a different mix of inputs including fossil fuels and biofeedstock are co-processed.

The issue: In this case study, where different type of feedstock including biomass/biofuels are co-processed in the same conversion unit, two different Delegated Acts (DA co-processing and DA RFNBO/RCF methodology) may apply with different guidelines in terms of how the allocation of the different type of feedstock in the outcome should be determined, potentially in contradiction and leading to an ambiguity in how to determine the % bio-content in the final product. The ambiguity arises due to the following differences in approaches: DA co-processing is proposing to use C14 isotope measurement (i.e. tracking biogenic carbon), while DA RFNBO/RCF methodology is using allocation based on energy content (such as renewable energy fraction in the total relevant energy inputs into the process for determining an RFNBO fraction of production).

Interpretation: Application of DA Co-processing rules for fossil/bio cases and energy allocation (DA GHG methodology) for the cases where RFNBO/RCF is co-processed with bio and/or fossil feedstock, with some flexibility given to operators in case they want to demonstrate via 14C that the share of bio in the product is higher than the share obtained using energy allocation.

#### 5. RFNBO hydrogen as intermediate for production of conventional fuels. Link with RED II(I) Industry.

Case Study: Use of RFNBO hydrogen as intermediate product when used as inputs to a hydrotreatment unit in a conventional refinery (a similar case could apply to a biofuel production unit).

The issue: RFNBO hydrogen as intermediate is recognised as a compliance option in RED-II and RED-III transport (Article 25). Moreover, its energy content is excluded from the RED III Industry target (Article 22a) when used as inputs for production of both transport fuels and biofuels. In this context, a footnote on article A.3 (Annex) of the DA GHG methodology states that *RFNBO used as intermediate products for the production of conventional fuels are not considered*. A strict interpretation of article A.3 may lead to the absence of criteria to estimate the GHG emissions referring to the intermediate fraction, creating a legal gap when using intermediate RFNBO in compliance with RED transport target and eventually compromising eligibility.

Interpretation proposed: Based on the footnote and related RED articles mentioned above, the electrolyser unit would define the boundary limits for the calculation of both energy content of RFNBO intermediate and associated GHG emissions. The energy content of the RFNBO intermediate as input to the conventional process unit will qualify for RED compliance with no associated fossil process emissions being allocated from hydrotreater / fossil inputs.

#### 6. Recognition of e ex-use credits waste diverted from landfilling or burnt for district heating to RCF production

Case Study: Recycled Carbon Fuels from waste “not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC” (REDII, art. 2, pt 35) where the waste gas has been diverted from landfill/incineration without energy recovery or being burnt in incineration with energy recovery, including the case in which waste is burnt to provide district heating.

The issue: A key goal of EU waste policy is to cut the amount of waste sent to landfill. In this sense, RCF could be an option to valorise the non-recyclable fraction of this waste. However, a strict interpretation of DA GHG methodology in isolation, without considering other provisions in different pieces of legislation, would lead to a case in which future RCF routes are disincentivised with no recognition from the existing use or fate of the inputs (e ex-use) (e.g. when qualifying feedstocks for RCF production are being diverted from landfilling or burnt to provide district heating).

Interpretation: According to the “*Methodology for GHG Emission Avoidance Calculation*” of the ETS Innovation Fund, waste currently destined for landfill or incineration without energy recovery are both part of the same case and avoided emissions can be fully counted as negative. Based on the above and seeking for consistency between the DA GHG methodology for RFNBO/RCF and the aforementioned one in the ETS Innovation Fund, FuelsEurope understanding is that the case of redirecting waste from landfill should be treated in the same way as waste used for incineration without energy recovery.

## 7. Others

### 7.1. Transport related emissions in practice

In the absence of disaggregated default values for the  $e_{td}$  term as in RED II Annex part C for biofuels, look-up tables from reliable external sources in terms of emissions per transport mode, distance and eventually load factors should be allowed.

### 7.2. CO<sub>2</sub> from industrial sources with sustainable bio-origin, no combustion related: Interpretation on the CO<sub>2</sub> source eligibility

There could be cases of industrial point sources, such as paper & pulp industry, where part of the emissions would have a bio-origin, released during the process itself and not as a result of any combustion (e.g. these process related emissions with bio-origin account for ~2/3 of the CO<sub>2</sub> emissions in the aforementioned industry). In this case, a strict interpretation of the DA GHG methodology (Annex point 10 option a) may lead to a case in which CO<sub>2</sub> from these sources appears to only be allowed before 2041. Moreover, CO<sub>2</sub> stemming from combustion of biomass or biofuels for purpose of electricity generation would only be allowed before 2036. The wording in article A.10a (Annex) “CO<sub>2</sub> stemming from the combustion of fuels for electricity generation” is deemed ambiguous and may lead to different interpretations.

### 7.3. E ccs term: negative emissions leading to negative carbon intensity RFNBO / RCF fuels

As stated in the DA GHG methodology (Annex A.1), the term **e ccs** refers to all the emission savings (credits) that can be generated from carbon capture and geological storage (CCS). When **applied to both process and input related emissions**, this CSS term could effectively lead to a RFNBO and/or RCF production fuel with associated negative emissions for compliance with RED II(I) and eventually FuelEU Maritime targets. Clear confirmation would help develop the related business cases.

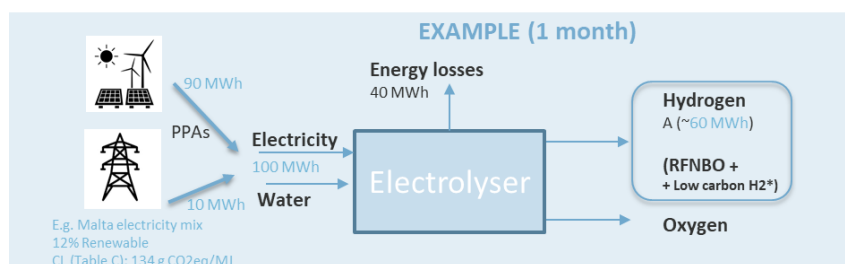
## DETAILED CASE STUDIES

### 1 Multiple electricity sources as simultaneous inputs to an electrolyser

#### 1.1 Link between DA for production of renewable H<sub>2</sub>, DA GHG methodology RFNBO / RCF & RED-T

**Case Study:**

Electrolyser with multiple sources of electricity as simultaneous inputs: fully renewable electricity from wind/solar (covered by PPA and complying with additionality, temporal and geographical correlation) + electricity from the grid (country mix).



**The issue:**

Absence of a clear interpretation on how much electricity from the input could qualify as RFNBO as compliance options against Renewable Energy Directive (RED) targets. Question mark about whether PPA are needed to account for the renewable share of electricity in the grid.

**Interpretation:**

The amount of renewable electricity and corresponding hydrogen production that can qualify as RFNBO in a given time interval is the **sum** of the fraction complying with the DA “fully renewability” criteria plus, for the fraction that does not qualify as fully renewable, the share of renewable energy in the electricity mix according to RED II Art. 27(3). Several considerations on the electricity sourced from the grid arise.

Questions leading to multiple interpretation		Interpretation (FE’s understanding based on DA and RED)
1.1	When multiple electricity inputs are sourcing an electrolyser, what is the <b>amount of renewable energy</b> could <b>qualify as RFNBO</b> to comply with RED targets?	The energy content of RFNBO that could be used by fuel suppliers to comply with RED-T targets would be <b>(a) + (b)</b> a) Fully renewable electricity that ends up in the energy content of the final fuel (complying with DA “rules for production of renewable Hydrogen”). b) Share of renewable electricity in the country mix (According to Article 27.3 in RED III) of the fraction that does not qualify as fully renewable
1.2	Could different sources of electricity be combined in the same <b>time interval</b> for both GHG and amount of renewable energy calculations compliant with RED targets?	According to article A.1 (Annex) of the DA GHG methodology, GHG emissions [...] <i>may be calculated for the entire production of fuels occurring during a period of at most one calendar month [...] providing that the minimum savings threshold of 70% is reached.</i> During the selected time interval and provided that the 70% threshold is reached, the total RFNBO production would be (a) + (b) as described in 1.1, regardless the carbon intensity of the grid itself (even if above 28.2 g CO <sub>2</sub> /MJ).
1.3	When the electricity mix is used to source an electrolyser: 1.3.1. Will all the renewable fraction in the country mix determine the amount of energy that could qualify as RFNBO (According to table C)? 1.3.2. Can be counted as RFNBO the share of H <sub>2</sub> obtained equivalent to the share of renewable in the grid in the year N-2, even if the carbon intensity of the grid is above 28.2 g CO <sub>2</sub> /MJ?	1.3.1 Based on the definition of RFNBO, the share of the renewable electricity produced from biomass/biofuels in the country mix should not qualify for RFNBO production.  However, according to the interpretation of recital (8) of the DA GHG methodology and the definition of renewable share of the grid in RED II (Art. 7(2)), a question arises around whether the average share of electricity from bio-origin should be deducted from the renewable share in the mix in order to determine the amount of RFNBO compliant with RED.

<p><b>1.4</b></p>	<p>For utilities sourcing electricity to be considered fully renewable (Carbon intensity equal to zero), all the criteria of the DA art 27.3 (consistently with DA “additionality”) would need to be met or only PPA/s would be required to demonstrate renewability?</p>	<p>In the absence of clear references to electricity used as utilities, the question remains around whether all units which would like to source renewable electricity to reduce the GHG intensity of their operations need to be certified as a process unit and therefore, would need to fulfil all the criteria stated in the DA “additionality” to be considered as <i>fully renewable</i> (with a carbon intensity equal to 0) or whether PPAs would be enough to demonstrate renewability.</p> <p>Similarly, for the recognition of the renewable share of the grid as RFNBO, FuelsEurope’s understanding is that no PPAs would be needed following ED II, Article 27.3 (where the calculation of the share of renewable electricity in the electricity supplied to road and rail vehicles shall refer to the two-year period before the year in which the electricity is supplied in their territory).</p>
<p><b>1.5</b></p>	<p>What “nature” is the non-RFNBO fraction in the output of the electrolyser and which Carbon Intensity should be attributed to that fraction?</p>	<p>In the case that electricity is sourced also from the grid:</p> <ul style="list-style-type: none"> <li>The non-RFNBO fraction in the output of the electrolyser with multiple electricity sources may qualify as <b>low carbon hydrogen</b> according to the Gas&amp;H<sub>2</sub> package: “<i>low-carbon hydrogen</i>’ means hydrogen the energy content of which is derived from non-renewable sources, which meets a greenhouse gas emission reduction threshold of 70%”.</li> <li>Both RFNBO and Low Carbon Hydrogen fraction of the outcome will have the same Carbon Intensity according to the article A.1 (Annex) of the DA GHG methodology (mix of inputs).</li> </ul> <p>All the above is subject to the final DA on low carbon hydrogen and alignment with the interpretation on the same Carbon Intensity for both RFNBO and non-RFNBO hydrogen outcome is deemed essential.</p>

Interpretation (Summary – Case Study)

### EXAMPLE (1 month)

**Step 1. DA Additionality**

- Electricity from the grid not considered as fully renewable  
% fully renewable electricity as material input: 90/100 < 90%

**Step 2. DA GHG methodology**

- CI of fully renewable: 0  
90 MWh with CI = 0
- CI of grid from Table C or methodology Annex.  
Emissions from electricity: 10 MWh \* 1000 \* 3,6 MJ/MWh \* 134 g CO2eq/MJ = 4.8 t CO2eq  
Rest of emissions for RFNBO production (LCA) assumed 0
- Total emissions from RFNBO production  
Emissions (E): Emissions from RFNBO LCA / total hydrogen produced  
Emissions (E): 4.8 t CO2eq / (60 MWh \* 1000 \* 3.6 MJ/MWh) = 22.3 g CO2eq/MJ H2 produced
- Fossil fuel comparator: 94 g CO2/MJ  
Emissions fossil (Ef) = 60 MWh \* 1000 \* 3,6 MJ/MWh \* 94 = 33.8 t CO2eq
- Emission savings: (Ef – E) / Ef  
Savings = (94 g CO2/MJ f – 22.3 g CO2/MJ H2) / 94 g CO2/MJ f = 76%

**As E savings > 70% → H2 qualifies as RFNBO**  
**With an unique Carbon Intensity (DA [1] mix of inputs – simplification): 22.3 g CO2eq / MJ**

**Step 3. How much can be used to comply with RED?**  
Interpretation

**Total Renewable Energy claimed as RFNBO against RED-II(I) Transport target:**

**Total = (a) + (b)**

a) Fully renewable electricity into the energy content of the fuel  
60 MWh \* 90% = 54 MWh RFNBO

b) Article 27.3 in RED considering the % of renewable in the grid (y N-2) into the energy content of the fuel  
60 MWh \* 10% (grid as material input) \* 12% (Share RES in the grid y N-2) = 0,7 MWh

**TOTAL**

- Renewable energy as RFNBO in RED: **54,7 MWh**
- With the Carbon Intensity calculated in Step 2: CI RFNBO: 22,3 g CO2eq/MJ

Note (\*). The non-RFNBO fraction of the hydrogen production (up to 60 MWh) qualifies as low carbon hydrogen. Art. 2 of Gas&H2 package: “low-carbon hydrogen’ means hydrogen the energy content of which is derived from non-renewable sources, which meets a greenhouse gas emission reduction threshold of 70%”



## 1.2 Selection of the time interval and time period for GHG emission calculations

### **Question:**

Would a one-month period be allowed for GHG emission calculations after 2030? Or the time period shall always follow the timing dictated by the temporal correlation?

### **The issue:**

The two DA referring to RFNBO present different considerations regarding the “time interval” (“DA GHG Methodology up to 1 month”) and “temporal correlation” (DA “additionality” 1h after 2030) which could lead to multiple interpretations.

Article A.1 (Annex) in the DA GHG methodology refers to:

*[...] The greenhouse gas emissions intensity may be calculated as an **average** for the entire production of fuels occurring during a period of **at most one calendar month** but may also be calculated for shorter time intervals. Where **electricity qualifying as fully renewable** according to the methodology set out in Directive 2018/2001 is used as input that enhances the heating value of the fuel or intermediate products, the **time interval shall be in line with the requirements applying for temporal correlation**. Where relevant, greenhouse gas emissions intensity values calculated for individual time intervals may then be used to calculate an average greenhouse gas emissions intensity for a period of up to one month, provided that the individual values calculated for each time period meet the minimum savings threshold of 70%. [...]*

Questions leading to multiple interpretation		Possible interpretations (FE’s understanding based on DA and RED)
<b>1.6</b>	How to understand the link between two different considerations regarding the “time period” (“DA GHG Methodology up to 1 month”) and “temporal correlation” (DA “additionality” 1h after 2030)?	<p>FuelsEurope’s interpretation is that:</p> <ul style="list-style-type: none"> <li>• <b>“Time interval” is defined by temporal correlation</b> (1 month until 2030 / 1 h after 2030)</li> <li>• <b>“Time period” defines the aggregation level of different periods over which GHG intensity values are to be calculated, each of them meeting 70% reduction target, including the GHG impact of electricity &amp; other contributors</b> (e.g. transport emissions). <b>In this regard</b>, GHG intensity can be always averaged up to one month (<i>article A.1 Annex</i>).</li> </ul>
<b>1.7</b>	Which values should then be used to calculate the average in 1 month?	<p>When averaging data in the period up to one month, a question remains about whether subtracting the part that do not meet the fully renewability criteria would be needed.</p> <p>FuelsEurope questions whether, after 2030 when the 1h temporal correlation is in place, it would still be possible to average the hours where electricity is also sourced from the grid provided that the GHG threshold is met within that hour.</p> <p>Further clarification is deemed essential to ensure a homogeneous interpretation across operators, certification bodies and auditors.</p>

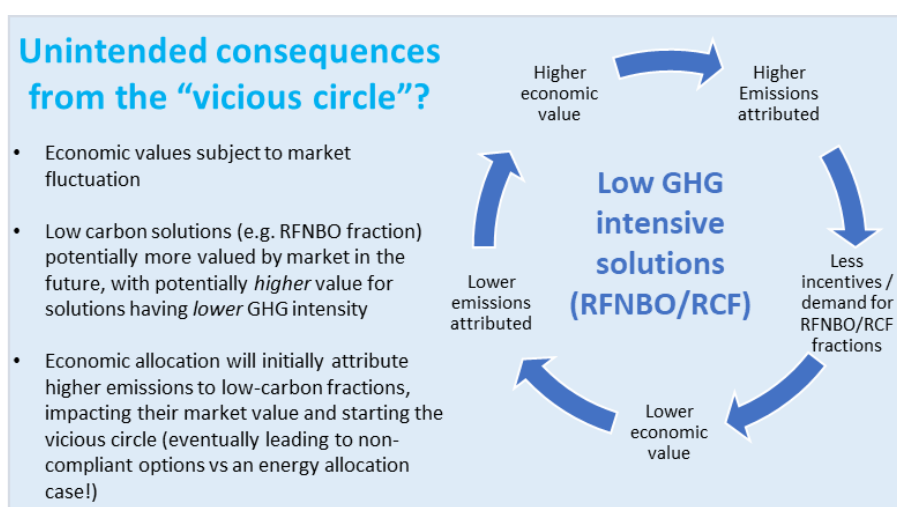
## 2 Multiple co-products: Implications derived from choice of allocation method. The « vicious circle »

### Case Study:

Same case study as 1 (as an illustrative example). Electrolyser sourced by both fully renewable electricity and electricity from the mix.

### The issue:

A strict interpretation of DA GHG methodology may lead to severe unintended consequences derived from the application of economic allocation. A “vicious circle” will likely be created, as described in Case Study 2 of this paper where a scenario involving O<sub>2</sub> as a commercialised co-product is presented. As O<sub>2</sub> has no energy content, energy allocation will apply to H<sub>2</sub> RFNBO and low carbon H<sub>2</sub> fractions, resulting in two different carbon intensity values for each of them, higher for the H<sub>2</sub> RFNBO fraction, compromising eligibility of H<sub>2</sub> RFNBO artificially and creating instability (fluctuations) in their market value.



Note. This vicious circle may appear in other industrial cases. The multiply-sourced electrolyser serving as an illustrative example.

### Interpretation proposed:

**Two-step allocation approach** between energy and non-energy content fractions, consistently with the wording included in the DA GHG methodology, is proposed leading to the same carbon intensity for both RFNBO H<sub>2</sub> and low carbon H<sub>2</sub>.

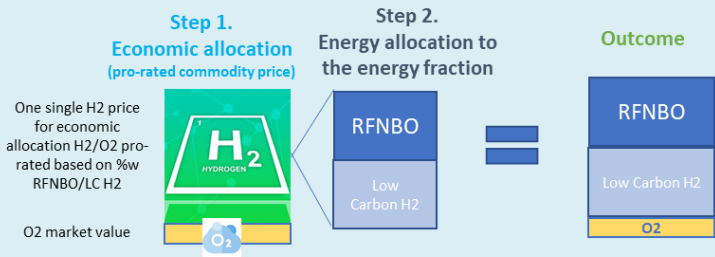
Questions leading to unintended consequences		Interpretation (FE’s understanding based on DA)
2.1	What is the impact of Oxygen in the allocation method?	This case falls into the multiple co-products case (Article A.15 (Annex)) where not all co-products have energy content due to the presence of O <sub>2</sub> (with no energy content): <ul style="list-style-type: none"> <li>- In the case that O<sub>2</sub> is not vented, its presence would lead to <b>economic allocation</b> of emissions to the co-products based on their economic value (average factory-gate value over 3y or commodity prices).</li> <li>- If O<sub>2</sub> is vented, it would be considered as a waste (and not as a product) and therefore, <b>energy allocation</b> would be applied.</li> </ul>
2.2	What kind of unintended consequences are derived from a strict interpretation of the economic allocation when both RFNBO and non-RFNBO hydrogen fractions, as well as O <sub>2</sub> , are produced?	The implications of a strict interpretation of the economic allocation rule to this case would trigger unintended consequences: <ul style="list-style-type: none"> <li>- “Vicious circle”: Pure economic allocation could potentially lead to different (higher) GHG emissions allocated to RFNBO fraction vs Low Carbon Hydrogen (non-RFNBO), reducing their market value (less incentives to produce RFNBO) and leading to a different allocation of emissions in the next iteration.</li> <li>- It would lead to an inconsistency with article 1 of the same DA GHG methodology which states that mix of inputs would lead to the same Carbon Intensity for the products, expecting the same value for both RFNBO and non-RFNBO Hydrogen fractions.</li> </ul>



**2.3** How to avoid entering into an iterative “vicious circle” when both RFNBO and non-RFNBO hydrogen fractions, as well as O<sub>2</sub>, are produced if economic allocation is chosen?

A two-step approach, as an interpretation of the DA GHG methodology (both articles A.1 and A.15 in Annex) would consist on:

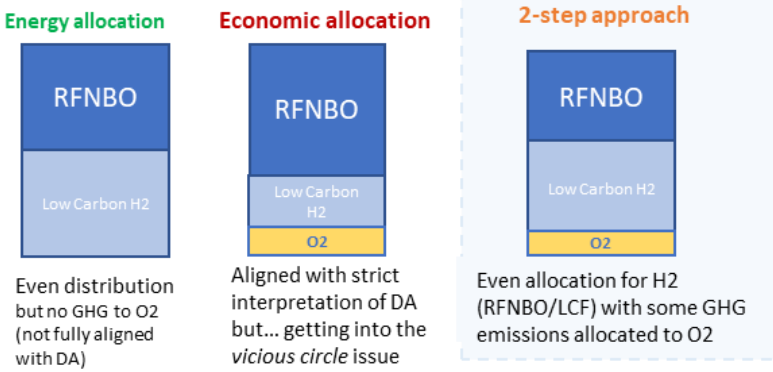
- Step 1. Economic allocation** between the fraction of the output with and without energy content
- Step 2. Energy allocation** to allocate the GHG emissions to the different fractions with energy content



The two-step approach, interpretation consistent with both articles A.1 and A.2 (Annex) as currently written, would allow to:

- Decouple the emission allocation to RFNBO and non-RFNBO hydrogen from their relative market value (avoiding the vicious circle)
- Determine same Carbon Intensity values for both RFNBO and non-RFNBO (Low Carbon) hydrogen, consistently with energy allocation (in the event of O<sub>2</sub> being vented)
- Allocate GHG emissions to the non-energy fraction (O<sub>2</sub>) based on its market value, incentivising its use as a product (instead of venting it to the air)

Interpretation (Outcome)

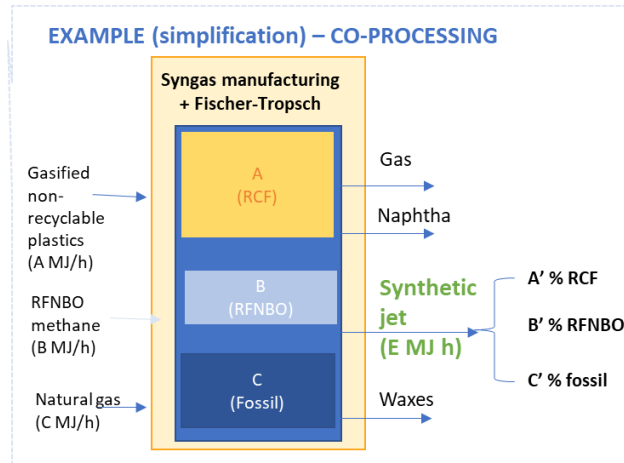


This 2-step approach could be potentially applied to the cases in which either the non-energy content product is either produced in very small quantities versus the main energy products and/or they are unintended outcome of the process.

3 Mix of inputs (Exception): Co-processing. Implications for the calculation of both share of each type of fuel in output and associated carbon intensities


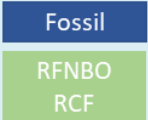
**Case Study:**

As an illustrative example, a Syngas manufacturing and Fischer-Tropsch (FT) conversion unit is presented where a different mix of inputs including fossil fuels are co-processed, falling under the exception laid down in article A.1 (Annex) and leading to a different carbon intensity of the fractions in the output estimated [...] *on a proportional basis of the energetic value of inputs* [...].



**The issue:**

The co-processing of different renewable, recycled, biogenic and/or fossil feedstocks via syngas and Fischer-Tropsch (FT) pathway poses a number of questions regarding whether individual carbon intensity values can be estimated for each fraction of the outcome, the differences between the *feedstock* and *input* concept in a multi-step conversion process (i.e. process consisting of multiple conversion units) and the implications in terms of their different Lower Heating value when either a *feedstock* or an *input* based allocation is followed, the actual estimate of the carbon intensity or the possibility to apply free allocation of the inputs to the different co-products (in terms of type of input). Beyond the Delegated Act GHG methodology, the **clear recognition of the qualification of the fractions in the outcome as different type of fuels** based on the inputs is deemed relevant also in the context of the ReFuelEU Aviation regulation. The key question in the case study is whether allocation on LHV basis should apply to (dry) feedstocks or to syngas.<sup>2</sup>

Questions leading to multiple interpretation		Possible interpretations (FE's understanding based on DA)	
<b>3.1</b>	How exception in article A.1 should be applied to the different fractions of synthetic fuel, as an example, in the case study presented?	<p>Article A.1 (Annex) clearly states that, in the case of a mix of inputs, including fossil, different GHG emission intensity values for each fraction in the output shall be estimated based on <i>a proportional basis of the energetic value of inputs, distinguishing between the conventional fraction and the part of the process that it is based on RFNBO/RCF</i>. Based on this, two different interpretations may be followed by auditors, potentially leading to a different CI for RCF and RFNBO fractions.</p> <p><b>Interpretation 1:</b> One CI per type of fuel (RFNBO / RCF separate CIs)</p> 	<p><b>Interpretation 2:</b> a CI for conventional output (fossil fuel or bio) as Int.1 but the same CI for the RFNBO/RCF (As a "block")</p> 

<sup>2</sup> Technical clarification: Syngas is a mixture of carbon monoxide and hydrogen. Feedstocks, such as biomass, renewable power, CO<sub>2</sub>, water, waste, fossil, are converted into carbon monoxide and hydrogen (also called syngas); next, carbon monoxide and hydrogen are combined in an FT unit to make FT wax, which is next converted in a hydroprocessing unit (with extra addition of renewable hydrogen, as needed) into final FT products (fuels), like kerosene.

<p><b>3.2</b></p>	<p><b>How should the shares of RFNBO, RCF and other fuels be determined in the case of co-processing of RFNBO, RCF and other fuels (like bio-fuels or fossil fuels)?</b></p> <p>a) Using LHV of feedstocks (viz. renewable hydrogen and dry biomass); or</p> <p>b) Using LHV of renewable hydrogen and LHV of syngas (viz. a mixture of carbon monoxide and hydrogen obtained from bio-feedstock or waste (RCF) feedstock or fossil feedstock)?</p>	<p>Syngas (aka synthesis gas) is a mixture of carbon monoxide and hydrogen that can be produced from a variety of feedstocks, incl. biomass, waste, CO<sub>2</sub> and power (H<sub>2</sub>), in a syngas manufacturing unit (also called: gasification unit). Syngas should have a sufficiently high H<sub>2</sub>/CO ratio (viz. ratio of ~2) before it can be sent to Fischer-Tropsch synthesis or methanol synthesis. However, syngas made from biomass or waste will typically have a too low H<sub>2</sub>/CO ratio (unless there is a lot of shift applied, i.e. CO shifted to CO<sub>2</sub> with addition of water in order to make H<sub>2</sub>, with much of carbon getting emitted as CO<sub>2</sub>, as a result). For an efficient use of carbon in a biomass or waste feedstock, addition of (renewable) hydrogen is needed before resulting syngas has the right H<sub>2</sub>/CO ratio to be sent to Fischer-Tropsch or methanol synthesis.</p> <p>For the allocation of the GHG emission intensity and the relative share in the output, a reference to the energetic value of “inputs” is explicitly included in the text of the DA GHG methodology. However, in the case study presented and based on the syngas related considerations mentioned above, there is a clear difference in between the <b>feedstock</b> concept (e.g. the non-recyclable part of the Municipal Solid Waste, bio-feedstocks) and the <b>input</b> to the common co-processing unit (the Fischer-Tropsch unit, as the main feedstocks, e.g. MWS or biomass, needs to be pre-treated in a gasifier to produce the syngas that would then be co-processed in a common unit, i.e. Fischer-Tropsch unit,) <b>leading to potential different interpretations across certification bodies.</b></p> <p>Based on the interpretation of the DA GHG methodology, a question arises regarding whether the LHV of “inputs” to the common co-processing unit (meaning, LHV of syngas after gasification of biomass or waste and LHV of renewable hydrogen) or the LHV of “feedstock” (dry biomass, waste, renewable hydrogen) shall be applied for the calculations related in article A.1 (Annex) DA GHG emissions).</p> <p>Clear guidance in this regard is deemed essential consistently with the certification approach, with clear instructions still missing on whether certification should be provided per unit, with the syngas manufacturing unit being considered as a separate process unit, or certification should be provided per plant consisting of several processing units.</p> <p>Alignment between certification schemes regarding this “envelope” for GHG calculation and calculation of fractions of different types of fuels is deemed essential to ensure a homogeneous interpretation in this regard.</p>
<p><b>3.3</b></p>	<p><b>What GHG emissions should be allocated to each fraction on a proportional basis of the energetic value of inputs?</b></p>	<p>The same exception in article A.1 (Annex) reads [...] <i>assuming that the process part are otherwise identical</i> [...] which could lead to, at least, two different interpretations:</p> <p><u>Int. a)</u> A strict interpretation may lead to the assumption that only process related GHG emissions can be different for each type of fuels or “block” (refer to 3.1), estimating the carbon intensity of the non-fossil block as a pro-rated average of the energetic value of inputs.</p> <p><u>Int. b)</u> An alternative proposal would allow to estimate different carbon intensity (CI) values for each fraction (or block) depending on the nature of the inputs based on the differentiation between:</p> <ul style="list-style-type: none"> <li>- Upstream emissions: emissions from inputs (before the co-processing unit) could be different for each fraction depending on the origin (and previous ex-use) of each feedstock</li> <li>- Downstream emissions: Process GHG emissions, transport, distribution and use would be the same for all fractions (After the co-processing unit), on proportional basis of the energetic value of inputs.</li> </ul> <p>Both interpretations, if left open to the auditor criteria, would lead to very different GHG emissions for the different fractions.</p>

<p><b>3.4</b> How the <b>share of different type of fuel</b> in outcome can be calculated? <b>Free allocation</b> of the inputs to a fraction / different fractions in outcome would be possible?</p>	<p>Based on article A.1 (Annex), the same principle could be applied to determine the share (%) of each type of fuel in the outcome. In that sense, the same % of each type of input can also be applied to the outputs (assuming that all inputs end up in the fuel in the same % as in the input to the co-processing unit).</p> <p>An alternative approach could allow a <b>free allocation</b> of the RFNBO/RCF, bio and/or fossil content to different co-products (without using the reference to the relative share (energy content) in the input as the basis).</p>
<p>An example of how the FuelsEurope’s interpretation, around article 1 in article 3.a (Annex DA GHG methodology) is detailed below, showing how both GHG emissions and share of each type of fuel in the final outcome could be determined:</p> <div style="display: flex; justify-content: space-between;"> <div data-bbox="343 660 845 1187" style="width: 45%;"> <p><b>EXAMPLE (simplification) – CO-PROCESSING</b></p> </div> <div data-bbox="893 660 1396 1164" style="width: 50%;"> <p><b>Interpretation 1 as example (details)</b></p> <p>This exception applies to all emissions (LCA) and not only to process emissions. How would it be applied in practice?</p> <div style="display: flex; justify-content: space-around;"> <div style="border: 1px solid black; padding: 5px;"> <p>CO2 transport and distribution= etd</p> </div> <div style="border: 1px solid black; padding: 5px;"> <p>CO2 use= eu</p> </div> </div> <p>Only energy inputs are material inputs (simplification)</p> <p>↑ Transport and distribution</p> <div style="border: 1px solid black; padding: 5px;"> <p> <math>A' = \% RCF = A / (A+B+C)</math>  <math>B' = \% RFNBO = B / (A+B+C)</math>  <math>C' = \% Fossil = C / (A+B+C)</math> </p> <p> <math>CI\ of\ diesel\ RCF = ei\ RCF + A' \cdot ep + A' \cdot etd + A' \cdot eu</math>  <math>CI\ of\ diesel\ RFNBO = ei\ RFNBO + B' \cdot ep + B' \cdot etd + B' \cdot eu</math>  <math>CI\ of\ diesel\ fossil = ei\ fossil + C' \cdot ep + C' \cdot etd + C' \cdot eu</math> </p> <p>Where : <math>ei_{RCF} \neq ei_{RFNBO} \neq ei_{fossil}</math></p> </div> </div> </div>	
<p><b>3.5</b> How to link the co-processing case between DA GHG methodology and ReFuelEU Aviation regarding the recognition of different fractions in the final fuel as SAF, in compliance with ReFuelEU mandate and submandate? Would both new and existing facilities be considered in the same manner?</p>	<p>As co-processing is explicitly allowed in ReFuelEU Aviation, the <b>different fractions</b> produced in a mixed inputs (and/or co-processing) scenarios <b>will qualify against the main mandate</b> (A' + any bio fraction) and the <b>sub-mandate</b> (RFNBO B') according to the nature of each material.</p> <p>This would be in line with the assumption on the DA GHG methodology regarding the estimate of the share of different type of fuels in outcome based on the nature (%) of each material input into the process, viz. based on corresponding energy inputs into the process.</p> <p>In this regard, the different nature of fractions of a synthetic jet stream could be recognised for compliance with the ReFuelEU aviation subtargets in the proportion calculated based on the energy content in the material input. This could be applied not only to a new facilities but also to existing units co-processing different type of inputs.</p>

#### 4 Biofuel production and RFNBO/RCF fuels. Link with DA Co-processing

##### Case Study:

As an illustrative example, a Syngas manufacturing and Fischer-Tropsch conversion unit is presented where a different mix of inputs including fossil fuels **and bio-feedstock are co-processed**.

##### The issue:

In this case study, where different type of feedstock including biomass/biofuels are co-processed in the same conversion unit, two different Delegated Acts (DA co-processing and DA RFNBO/RCF methodology) may apply with different guidelines in terms of how the allocation of the different type of feedstock in the outcome should be determined, potentially in contradiction and leading to an ambiguity on how to determine the % bio-content in the final product:

1) *DA GHG methodology for RFNBO/RCF: Co-processing*

Based on article A.1 (Annex), the allocation of each type of fuel in output is based on the **relative energy content** in material inputs.

2) *DA Co-processing of biofuels and conventional fuels*

The draft text of the DA co-processing covers the case in which bio-feedstock is co-processed with fossil-based ones, allowing different methods to estimate the content of biofuel in the final fuel (e.g. mass, energy, yield) but always verified by C14 analysis. In this case, the C14 analysis may lead to a different % of biofuel content in the final outcome when compared to an energy allocation based on inputs, relevant for compliance with different pieces of regulation/directives.

##### Interpretation proposed:

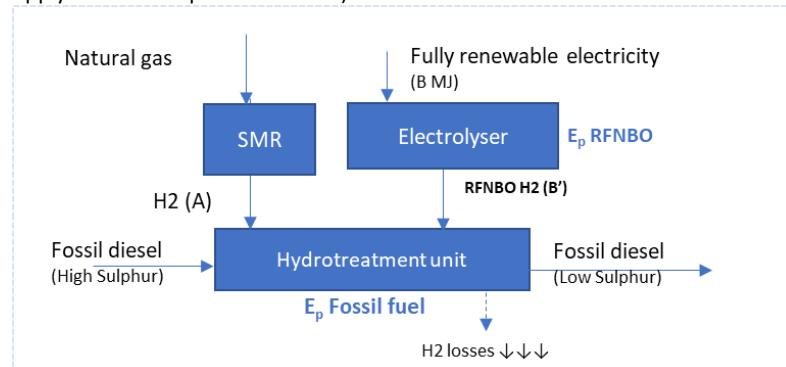
DA Co-processing rules for fossil/bio cases and energy allocation (DA GHG methodology) for the cases where RFNBO/RCF is co-processed with bio and/or fossil feedstock, with some flexibility given to operators in case they want to demonstrate via 14C that the share of bio in the product is higher than the share obtained using energy allocation.

Questions leading to multiple interpretation	Possible interpretations (FE's understanding based on DA)
<p><b>4.1</b> How should the bio-fraction in the outcome be determined in a case where RFNBO, RCF, biomass/biofuel and/or fossil-based feedstocks being co-processed in the same unit?</p>	<p>Two Delegated Acts could be applied to this case, eventually leading to a different % bio-content in the final fuel. In the absence of a clear and consistent approach to define the “rules” for this case, the following interpretation is presented:</p> <ul style="list-style-type: none"> <li> <b>Case 1. Bio + Fossil feedstock → DA Co-processing rules (C14)</b>                      It is considered that the DA co-processing applies when biofuel/biomass is co-processed with fossil-based feedstock where the <b>bio-content</b> in outcome is to be ultimately determined by <b>C14 analysis</b>.                 </li> <li> <b>Case 2. Co-processing of bio, RFNBO/RCF and/or fossil</b>                      In this case, it is assumed that the <b>DA GHG methodology for RFNBO/RCF rules over the DA co-processing</b> and therefore, the share of each type of fuel in outcome is to be determined based on <b>% energy in material inputs</b>.                      In this context, an <b>optional 2-step approach</b> would also be allowed, providing flexibility to the operators who would like to eventually claim, based on C14, a higher bio content in the output.                 </li> </ul> <div style="border: 1px solid black; padding: 10px; margin-top: 10px;"> <p style="text-align: center;"><b>Case 2. Mix of bio, RFNBO/RCF and/or fossil</b></p> <p style="text-align: center;">Energy allocation (DA GHG Methodology) ruling over DA co-processing</p> </div>

## 5 RFNBO hydrogen as intermediate for production of conventional fuels. Link with RED II(I) Industry.

### Case Study:

Use of RFNBO hydrogen as intermediate product when used as inputs to a hydrotreatment unit in a conventional refinery (a similar case could apply to a biofuel production unit).



### The issue:

RFNBO hydrogen as intermediate is recognised as a compliance option in the context of the RED (see extract from RED II(I) article 25) below:

*[...] Member States shall take into account RFNBO when they are used also as intermediate products for the production of biofuels provided that the GHG reduction achieved by the use of renewable fuels of non-biological origin is not considered in the calculation of the GHG savings of the biofuels [...].*

Moreover, the energy content of RFNBO H<sub>2</sub> used as inputs for production of both conventional fuels and biofuels is excluded from the RED III Industry target (Article 22a.1.a.i) when used as inputs for production of both transport fuels and biofuels:

*[...] For the calculation of the denominator, the energy content of hydrogen for final energy and non-energy purposes shall be taken into account, excluding: (i) **hydrogen used as intermediate products for the production of conventional transport fuels and biofuels**; [...]*

In this context, a footnote on article A.3 (Annex) of the DA GHG methodology states that *RFNBO used as intermediate products for the production of conventional fuels are not considered*:

*[...] The relevant energy for material inputs is the lower heating value of the material input that enters into the molecular structure of the fuel.<sup>1</sup> [...] <sup>1</sup> Footnote: Renewable liquid and gaseous transport fuels of non-biological origin used as intermediate products for the production of conventional fuels **are not considered**".*

A strict interpretation of article A.3 (Annex) may lead to the absence of criteria to estimate the GHG emissions to the intermediate fraction and create a legal gap when using intermediate RFNBO in compliance with RED transport target, where it is clearly recognised as compliance options. In the absence of more clarity on this case, multiple interpretations may also end up in different GHG emissions estimate, eventually compromising eligibility of this option when compared with the 70% threshold.

### Interpretation proposed:

Based on the footnote and related RED articles mentioned above, the electrolyser unit would define the boundary limits for the calculation of both energy content of RFNBO intermediate and associated GHG emissions. The energy content of the RFNBO intermediate as input to the conventional process unit will qualify for RED compliance with no associated fossil process emissions being allocated from hydrotreater / fossil inputs.



Questions leading to multiple interpretation	Possible interpretations (FE's understanding based on DA and RED)
<p><b>5.1</b> What is the amount of energy that qualifies as RFNBO intermediate to comply with RD-T targets?</p>	<p>Footnote on article A.3 (Annex) is subject to multiple interpretations. Consistently with the RED III Industry target which excludes all the energy content of RFNBO as inputs for the production of both conventional and biofuels, FuelsEurope interprets that <b>all the energy content in the hydrogen RFNBO used as intermediate product (input) to the production of conventional fuel is recognised for compliance with RED III-Transport.</b></p> <p>Note. (B' MJ as the energy content of the RFNBO H<sub>2</sub> as inputs to the Hydrotreatment unit in the case study presented above).</p> <p>This will be coherent with the footnote included in the draft Delegated act and effectively exclude the case of RFNBO as intermediate from the application of the general rule that would have implied that the final production becomes partially RFNBO, with its RFNBO share determined as relevant renewable energy input into the process divided by the total relevant energy inputs into the process, where relevant energy input of material inputs like renewable hydrogen is the lower heating value of said hydrogen (as described in article A.3 (Annex) of DA GHG methodology for RFNBO and RCF).</p>
<p><b>5.2</b> What are the boundary limits for the GHG emission calculation when RFNBO is used as an intermediate?</p>	<p>Consistently with the interpretation above, the boundary limits for GHG calculations of RFNBO as intermediate is defined around the electrolyser process unit:</p> <div data-bbox="730 958 1362 1283" data-label="Diagram"> <p>The diagram illustrates the boundary limits for RFNBO H<sub>2</sub> intermediate in a GHG calculation. It shows three main process units: SMR (Steam Methane Reforming), Electrolyser, and Hydrotreatment unit. Natural gas is an input to SMR, which produces H<sub>2</sub> (A). Fully renewable electricity (B MJ) is an input to the Electrolyser, which produces E<sub>p</sub> RFNBO. Both H<sub>2</sub> (A) and E<sub>p</sub> RFNBO are inputs to the Hydrotreatment unit. Fossil diesel (High Sulphur) is also an input to the Hydrotreatment unit, which produces Fossil diesel (Low Sulphur) and E<sub>p</sub> Fossil fuel. H<sub>2</sub> losses are shown as downward arrows from the Hydrotreatment unit. A dashed box highlights the boundary limits for RFNBO H<sub>2</sub> intermediate, which includes the Electrolyser and the Hydrotreatment unit. A note states: 'RFNBO H2 (B') qualifies under RED. With the CI of RFNBO H2'.</p> </div> <p>Based on the above, the formulae to estimate the GHG intensity of the RFNBO intermediate would be interpreted in the following way:</p> <div data-bbox="767 1402 1337 1509" data-label="Equation-Block"> <math display="block">E = e_i + e_{p_{\text{electrolyser}}} + e_{td} + e_{\text{H}_2} - e_{\text{CCS}}</math> <p><i>e<sub>i</sub></i> and <i>e<sub>p</sub></i> linked to electrolyser (no allocation of <i>e<sub>p</sub></i> HDS to H<sub>2</sub>)</p> </div> <p>Note.</p> <ul style="list-style-type: none"> <li>Both the emissions linked to inputs and process emissions are referring to the electrolyser and emissions in the use phase would be equal to zero (no GHG emissions in the combustion of H<sub>2</sub>).</li> <li>No fossil emissions (main feedstock to the Hydrotreatment unit) are assigned to RFNBO intermediate consistently with the “exclusion” in footnote and the boundary limits defined.</li> </ul> <p>This interpretation is reinforced by the fact that the fossil comparator (94 g CO<sub>2</sub> /eq) in the output already considers all the emissions from the Hydrotreatment unit. Allocation of additional fossil input/process related emissions to RFNBO intermediate would lead to <b>double-counting in this respect.</b></p>

<b>5.3.</b>	<p>Would the footnote or article A.3 (Annex) be adjusted to extend the exclusion of RFNBO intermediate also to the production of biofuels, consistently with the recently agreed RED II(I) text?</p>	<p>In RED III a provision is included regarding the possibility to account for RFNBO as intermediate as long as the savings have not been considered for the production of biofuels (to avoid double-counting). Operators which use RFNBO as intermediate products for the production of biofuels have the possibility to choose between:</p> <ol style="list-style-type: none"> <li>1) accounting the RFNBO as for conventional (fossil) fuels or</li> <li>2) consider the greenhouse gas emissions reduction achieved by the use of RFNBO in the calculation of the GHG savings of the biofuels.</li> </ol> <p>In line with the RED II(I) text, FuelsEurope inquires whether footnote 3 would also be expanded to refer to the production of both conventional fuels and biofuels.</p>
<b>5.4.</b>	<p>What are the emissions used for biomass fuels used as an utility in RFNBO production?</p>	<p>In the absence of clear guidelines, the DA GHG methodology for RFNBO/RCF should not overrule biofuel GHG emission calculation rules. Biomass fuel GHG emissions are certified under EU recognised voluntary scheme with biofuel methodology. These emissions are used in RFNBO GHG calculation and therefore, any combustion emissions of biomass fuels should be considered 0 in ep when included in the RFNBO emission calculation.</p>

## 6 How to consider the e ex-use credits waste diverted from landfilling or burnt for district heating to RCF production?

### Case Study:

Recycled Carbon Fuels from waste “not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC” (REDII, art. 2, pt 35) where the waste gas been diverted from landfill/incineration without energy recovery or being burnt in incineration with energy recovery, including the case in which waste is burnt to provide district heating.

### The issue:

A key goal of EU waste policy is to cut the amount of waste sent to landfill. In this sense, RCF could be an option to valorise the non-recyclable fraction of this waste. However, a strict interpretation of DA GHG methodology in isolation, without considering other provisions in different pieces of legislation, would lead to a case in which future RCF routes are disincentivised with no recognition from the existing use or fate of the inputs (e ex-use) (e.g. when qualifying feedstocks for RCF production are being diverted from landfilling or burnt to provide district heating).

### Interpretation:

- According to the “*Methodology for GHG Emission Avoidance Calculation*” of the ETS Innovation Fund (IF), published in November 2022, waste currently destined for landfill or incineration without energy recovery is both part of the same “Case 3” (pages 47-48) and avoided emissions are a credit and can be fully counted as negative.
- It is possible to continue accounting among the emissions from inputs’ existing use or fate (e ex-use) those avoided diverting the waste from landfill/incineration or being burnt to provide district heating after 2041 even if the waste to energy plants will be included in the list of the Annex I the Directive 2003/87/EC.

Questions leading to multiple interpretation	Possible interpretations (FE’s understanding based on DA and RED)
<p><b>6.1</b> How to consider the e ex-use credits waste diverted from landfilling or burnt for district heating to RCF production?</p>	<p>The DA GHG methodology states that GHG emissions from the production and use of recycled carbon fuels shall be calculated deducting the “emissions from existing use or fate of the inputs” (e ex-use) from the “emissions from supply of inputs” (e i).</p> <p>Point 10 Annex A states that “Emissions from existing use or fate include all emissions in the existing use or fate of the input that are avoided when the input is used for fuel production”. When producing recycled carbon fuels from waste “not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC” (REDII, art. 2, pt 35), the question arises on how the emissions from the existing use or fate of the inputs (e ex-use) should be calculated in the methodology in order to account for the emissions avoided by diverting the waste from landfill/incineration without energy recovery or being burnt in incineration with energy recovery.</p> <p>The “<i>Methodology for GHG Emission Avoidance Calculation</i>” of the ETS Innovation Fund (IF), published in November 2022, examines this matter as explained below:</p> <ul style="list-style-type: none"> <li>• <b>Waste currently destined for landfill or incineration without energy recovery</b> is both part of the same “Case 3” (pages 47-48) and avoided emissions are a credit and can be fully counted as negative. It is explicitly indicated that:</li> </ul> <p><i>“If municipal waste is diverted from landfill, the carbon emissions shall be assumed equal to those for incineration without energy recovery, meaning that the emission factor attributed to municipal waste at the point of collection will generally be negative. Although in practice landfill sequesters part of the carbon on a long-term basis, it is not desirable to encourage landfill for other environmental reasons (such as fugitive GHG emissions of methane (CH4)), potential impacts on health and other environmental media, e.g. soil or water, and resource depletion).”</i></p> <p><u>Example:</u> If the existing fate of municipal waste was incineration without energy recovery, the emissions from the incineration are avoided. This means the emissions attributed to using the waste are negative, i.e., avoiding the original fate saves emissions, so CO<sub>2</sub> credit for its novel use is recognised.</p>

		<ul style="list-style-type: none"> <li>• <b>Waste currently destined for incineration with energy recovery</b> (i.e. waste-to-energy plants) is part of "Case 1" (page 46) and the use of waste to produce a RCF, rather than being burned to produce electricity/heat, means that the same electricity/heat that was previously generated by waste must be generated from some other fuel, so those additional emissions must also be counted.</li> </ul> <p><u>Example:</u> A project is using municipal waste as an input, which is diverted from being burnt to provide district heating. The emissions avoided by the burning of the waste for district heating are offset by additional emissions incurred to replace that district heat, for example by using a natural gas boiler.</p> <p>Coherently with the above-mentioned methodology, FuelsEurope’s interpretation is that the calculation methodology defined by the Innovation Fund can also be applied to RCF, complementing the DA GHG methodology in the aspects where no specificity is provided.</p>
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## 7 Others

### 7.1 Transport related emissions in practice

**Question:**

How to estimate transport emissions (inputs / final fuels) in real operations consistently across Europe?

**The issue:**

Should transport emissions be estimated hourly for the final RFNBO / RCF, using “real data” may not be implementable in practice.

E.g. Unintended consequences could be derived (e.g. notably higher GHG emissions) for some “batches” based on non-predictable events (e.g. Traffic congestion in route).

**Interpretation:**

In the absence of disaggregated default values for the  $e_{td}$  term as in RED II Annex part C for biofuels, look-up tables from reliable external sources in terms of emissions per transport mode, distance and eventually load factors should be allowed.

	Questions leading to multiple interpretation	Possible interpretations (FE’s understanding based on DA and RED)									
7.1.1	How to estimate transport emissions (inputs / final fuels) in real operations consistently across Europe?	<p>Beyond the possibility for the fuel supplier to use actual values, consistent default values across Europe could be proposed to ease and homogenise the certification process:</p> <p>a) <b>Disaggregated default values</b> for transport and distribution could be proposed by EC in the context of the DA GHG methodology, similarly to biofuels in RED (Proposal: ‘etd’ as defined in Part C of the RED II Annex to be expanded to incorporate RFNBO / RCF)</p> <div style="border: 1px solid black; padding: 5px; margin: 10px 0;"> <p style="text-align: center; font-size: small;">Disaggregated default values for transport and distribution: ‘e<sub>td</sub>’ as defined in Part C of this Annex</p> <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="width: 50%;">Biofuel and bioliquid production pathway</th> <th style="width: 25%;">Greenhouse gas emissions – typical value (g CO<sub>2</sub>eq/MJ)</th> <th style="width: 25%;">Greenhouse gas emissions – default value (g CO<sub>2</sub>eq/MJ)</th> </tr> </thead> <tbody> <tr> <td>wheat straw ethanol</td> <td style="text-align: center;">7,1</td> <td style="text-align: center;">7,1</td> </tr> <tr> <td>waste wood Fischer-Tropsch diesel in free-standing plant</td> <td style="text-align: center;">10,3</td> <td style="text-align: center;">10,3</td> </tr> </tbody> </table> </div> <p>b) <b>A look-up table</b> to be used by certification bodies to estimate the etd emissions per means of transport / distance (and eventually load factor) consistently with the relevant external references listed in the DA GHG methodology (Annex 1.7) JEC-WTW report, ECOINVENT database, official sources such as the IPCC, IEA or government, other reviewed sources such as the E3 and GEMIS database and peer reviewed publications.</p> <div style="border: 1px solid black; padding: 5px; margin: 10px 0;"> <p style="font-weight: bold; font-size: small;">Example JEC Well-To-Tank v5</p> <ul style="list-style-type: none"> <li>• Diesel / Gasoline fuel distribution (long distance)               <ul style="list-style-type: none"> <li>• by barge (1200 t) 0,5 MJ/t.km</li> <li>• By pipeline: 0,0002 MJ / MJ fuel</li> </ul> </li> <li>• Diesel / Gasoline road local distribution (Average): 150 km</li> </ul> </div>	Biofuel and bioliquid production pathway	Greenhouse gas emissions – typical value (g CO <sub>2</sub> eq/MJ)	Greenhouse gas emissions – default value (g CO <sub>2</sub> eq/MJ)	wheat straw ethanol	7,1	7,1	waste wood Fischer-Tropsch diesel in free-standing plant	10,3	10,3
Biofuel and bioliquid production pathway	Greenhouse gas emissions – typical value (g CO <sub>2</sub> eq/MJ)	Greenhouse gas emissions – default value (g CO <sub>2</sub> eq/MJ)									
wheat straw ethanol	7,1	7,1									
waste wood Fischer-Tropsch diesel in free-standing plant	10,3	10,3									

	Conditioning & Distribution			
CD2	Syn diesel distribution (long distance)			
	Barge: 1200 (20%)			
	Distance	73y	km	500
	Diesel fuel		MJ/t.km	0.5040
R1	Oil emissions		g/t.km	0.0020
	Rail (20%)			
	Distance	72	km	250
	Pipeline (80%)			
LF1	Electricity (EU-mix LV)	EM,e	MJ/MJ <sub>fuel</sub>	0.0002
	Liquid fuel depot			
LF2	Electricity (EU-mix LV)	EM,e	MJ/MJ <sub>fuel</sub>	0.0004
	Liquid fuel local distribution			
LF3	Road truck	71	km	150
	Diesel dispensing at retail site			
LF3	Electricity (EU-mix LV)	EM,e	MJ/MJ <sub>fuel</sub>	0.0002

## 7.2 CO<sub>2</sub> from industrial sources with sustainable bio-origin, no-combustion related: Interpretation on the CO<sub>2</sub> source eligibility

### Question:

Would biogenic CO<sub>2</sub> emissions from paper & pulp process (which is ~2/3 of total CO<sub>2</sub> in that process) and similar biogenic CO<sub>2</sub> sources be allowed beyond 2041, for instance under condition that said processes meet criteria specified under point 10c of GHG methodology for RFNBO & RCF (e.g. using the same biogenic feedstocks as biofuels complying with the sustainability and GHG saving criteria)? Would CO<sub>2</sub> of biogenic origin generated as a result of combustion of bio-fuels for electricity generation be allowed before 2036 only?

### The issue:

There could be cases of industrial point sources, such as paper & pulp industry, where part of the emissions would have a bio-origin, released during the process itself and not as a result of any combustion (e.g. these process related emissions with bio-origin account for ~2/3 of the CO<sub>2</sub> emissions in the aforementioned industry). In this case, a strict interpretation of the DA GHG methodology (Annex point 10 option a) may lead to a case in which CO<sub>2</sub> from these sources appears to only be allowed before 2041.

Moreover, CO<sub>2</sub> stemming from combustion of biomass or biofuels for purpose of electricity generation would only be allowed before 2036. The wording in article A.10a (Annex) “CO<sub>2</sub> stemming from the combustion of fuels for electricity generation” is not clear and it is subject to different interpretations.

### Interpretation:

According to the point 10 c, CO<sub>2</sub> stemming from the production or the combustion of biofuels, bioliquids or biomass fuels complying with the sustainability and GHG saving criteria would be eligible for the recognition of *e ex-use credits* associated with the avoided emissions from existing use or fate **with no cut-off date**. However, an explicit reference to the biogenic CO<sub>2</sub> from process emissions (non-combustion related) is still missing, compromising eligibility. FuelsEurope is seeking for confirmation on whether such biogenic CO<sub>2</sub> (e.g. from pulp & paper) would be included in the same category as CO<sub>2</sub> listed under 10c, i.e. allowed as feedstock for RFNBO with no cut-off date.

	Questions leading to multiple interpretation	Possible interpretations (FE's understanding based on DA and RED)
7.2.1	Biogenic CO <sub>2</sub> from industrial point sources (e.g. paper & pulp industry) appears to only be allowed before 2041?	<p>As defined in point 10 of the Annex, meeting <b>at least one</b> of the conditions for CO<sub>2</sub> eligibility would be needed to ensure eligibility for RFNBO production beyond 2041. Based on point 10c, no cut-off date shall be applied to CO<sub>2</sub> stemming from the production or the combustion of biofuels, bioliquids or biomass fuels complying with the sustainability and GHG saving criteria. Similar CO<sub>2</sub> sources of biogenic origin (for instance emitted in the processes based on the same types of feedstocks as those that can be used for biofuels meeting the sustainability and GHG savings criteria), such as CO<sub>2</sub> stemming from paper &amp; pulp, should also be eligible with no cut-off date. If no explicit reference to the biogenic CO<sub>2</sub> from process emissions, no combustion related, is included, it will compromise eligibility of these sources beyond 2041.</p> <p><i>Annex DA GHG methodology (10):</i>  <i>[...] Emissions from existing use or fate include all emissions in the existing use or fate of the input that are avoided when the input is used for fuel production. These emissions shall include the CO<sub>2</sub> equivalent of the carbon incorporated in the chemical composition of the fuel that would have otherwise been emitted as CO<sub>2</sub> into the atmosphere. This includes CO<sub>2</sub> that was captured and incorporated into the fuel provided that <b>at least one of the following</b> conditions is fulfilled [...]</i></p> <p><i>(a) The CO<sub>2</sub> has been captured from an activity listed under Annex I of Directive 2003/87/EC and has been taken into account upstream in an effective carbon pricing system and is incorporated in the chemical composition of the fuel before 2036. This date shall be extended to 2041 in other cases than CO<sub>2</sub> stemming from the combustion of fuels for electricity generation;</i>  <i>[...] or (c) The captured CO<sub>2</sub> stems from the production or the combustion of biofuels, bioliquids or biomass fuels complying with the sustainability and greenhouse gas saving criteria and the CO<sub>2</sub> capture did not receive credits for emission savings from CO<sub>2</sub> capture and replacement, set out in Annex V and VI of Directive (EU) 2018/2001; o</i></p> <p>Assuming paper &amp; pulp process is using sustainable biogenic feedstocks (similar to feedstocks used for biofuels complying with the sustainability and GHG saving criteria and meet other criteria, as listed under 10c) FuelsEurope is seeking for confirmation on whether such biogenic CO<sub>2</sub> from paper &amp; pulp would be included in the same category as CO<sub>2</sub> listed under 10c, i.e. allowed as feedstock for RFNBO with no cut-off date.</p>

<b>7.2.2</b>	Biogenic fuels combusted for purposes of electricity generation appear to only be allowed before 2036?	CO <sub>2</sub> stemming from combustion of biomass or biofuels for purpose of electricity generation would only be allowed before 2036. However, the wording in article A.10a (Annex) “CO <sub>2</sub> stemming from the combustion of fuels for electricity generation” is not clear and it is subject to different interpretations.  FuelsEurope is seeking on clarity about whether article A.10a should read as “CO <sub>2</sub> stemming from the combustion of [any] fuels for electricity generation” or as “CO <sub>2</sub> stemming from the combustion of [fossil] fuels for electricity generation”.
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### 7.3 E ccs term: negative emissions leading to negative carbon intensity RFNBO / RCF fuels

**Question:**

As stated in the DA GHG methodology (Annex A.1), the term **e ccs** refers to the emission savings (credits) that can be generated from carbon capture and geological storage (CCS). When applied to both process and input related emissions, this CSS term could effectively lead to a RFNBO and/or RCF production fuel with associated negative emissions for compliance with RED II(I) and eventually FuelEU Maritime targets.

**The issue:**

Negative emissions (or carbon removals) are deemed essential to achieve the level of ambition stated by the Green Deal, aiming at net zero CO<sub>2</sub> GHG emissions by 2050 at European level. Clear recognition of the possibility to use this e ccs to generate a negative CI RFNBO/RCF fuel would add clarity for future business cases.

**Interpretation:**

Similarly as the biofuel carbon intensity estimate in RED II (e ccs term), capture and geological storage of CO<sub>2</sub> both process and input related emissions would qualify for negative carbon intensity RFNBO and RCF fuels.

	Questions leading to multiple interpretation	Possible interpretations (FE's understanding based on DA and RED)
<b>7.3.1.</b>	How should the term <b>e ccs</b> be applied for RFNBO production?	DA GHG methodology for RFNBO/RCF Annex A (17) states: " <i>Where a process for making renewable liquid and gaseous transport fuels of nonbiological origin or recycled carbon fuels produces carbon emissions that are permanently stored in accordance with Directive 2009/31/EC on the geological storage of carbon dioxide, this may be credited to the products of the process as a reduction in emissions under e ccs. [...]</i> "  Carbon capture process can be considered to be part of the RFNBO production, and if the CO <sub>2</sub> is not captured, it could be considered as an emission of the RFNBO production (provided that all emissions of the input (i.e. flue gas), that are avoided when the input is used for fuel production, are included in the negative emissions from existing use or fate). Intermittency of RFNBO production may create a situation where RFNBO production plant can't utilise all of the available CO <sub>2</sub> . Thus, FuelsEurope's understands that RFNBO should receive credits for permanently storing CO <sub>2</sub> even when the CO <sub>2</sub> is originating from the carbon feedstock/input.

**FuelsEurope, the voice of the European petroleum refining industry**

FuelsEurope represents with the EU institutions the interest of companies manufacturing and distributing liquid fuels and products for mobility, energy & feedstocks for industrial value chains in the EU.

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