Department
for Transport

Targeting net zero - next steps for the Renewable Transport Fuels Obligation

Hydrogen and renewable fuels of non-biological origin

Government response

July 2022

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1. Introduction and summary

The role of renewable fuels of non-biological origin and renewable low carbon hydrogen in transport to reach net zero

Transport decarbonisation is essential to the UK's commitment of reducing economy wide greenhouse gas (GHG) emissions to net zero by 2050. The transport sector now accounts for the largest proportion of UK GHG emissions, contributing 27% to domestic emissions in 2019[1]. The path to net zero in transport, as set out in the government's "Decarbonising Transport: a better greener Britain", will require new and innovative policies across the sector both in terms of how we power vehicles and how we use them.

It is clear that renewable hydrogen and its derivatives is likely to be a key low carbon and zero emission fuel in achieving net zero in transport. Adoption of hydrogen fuel cells can complement electrification across modes of transport including but not limited to buses, trains and heavy goods vehicles. It is also likely that hydrogen and other renewable fuels of non-biological origin (RFNBO) will be fundamental for other modes that may not be able to fully decarbonise otherwise, such as shipping and aviation. Analysis that supported the government's recent Hydrogen Strategy suggested transport demand could potentially reach 140TWh in 2050[2]. This is more than a hundred times the current available renewable hydrogen in the UK.

Through commitments in Hydrogen Strategy and Decarbonising Transport publications the government is supporting the development of the UK's hydrogen sector across the transport spectrum via a range of policy initiatives. One important mechanism is the Renewable Transport Fuel Obligation (RTFO) which has supported the supply of renewable hydrogen in transport since 2018.

The RTFO, hydrogen and renewable fuels of non-biological origin

Two types of renewable hydrogen are supported under the RTFO. The first is RFNBO hydrogen, which is produced by electrolysis powered by renewable electricity. This hydrogen can then be used to produce ammonia or methanol which are also considered

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[1] **Transport and environment statistics: Autumn 2021**
[2] Hydrogen Analytical Annex - See box 4.

RFNBOs and eligible for RTFO support. The second is biohydrogen produced from biological feedstocks, mainly biomethane via reformation.

Since 2018, all renewable hydrogen / RNFBO fuels have been eligible for reward under the RTFO development fuel target. These fuels, amongst others, receive development fuel certificates, which have a higher value than certificates in the main obligation. The higher valuation provides additional support to fuels of strategic importance, to address the difficulty and cost of delivering the technological advances needed to produce fuels for more challenging to decarbonise sectors, such as aviation and freight.

We reviewed several areas connected to RFNBO and renewable hydrogen in our consultation “Targeting net zero - Next steps for the Renewable Transport Fuels Obligation” which was published in March 2021.

Consultation overview

The original consultation ran between 25th March and 23rd April 2021, seeking views across six policy areas: target increases, recycled carbon fuels, RFNBOs (including hydrogen), sustainability criteria changes, civil penalties, and multiple incentives. Of these policy areas, all bar certain aspects of the RFNBO / hydrogen chapter were covered in a Government Response published in July 2021. That response, and the original consultation are available here: www.gov.uk/government/consultations/amending-the-renewable-transport-fuels-obligation-rtfo-to-increase-carbon-savings-on-land-air-and-at-sea

The July 2021 Response document also dealt with certain aspects of the RFNBO / hydrogen chapter. This included expanding support for RFNBOs to include use in fuel cell power systems in trains, ships, and specialist vehicles. The expansion has been in effect since January 2022.

The remaining RFNBO / hydrogen proposals were not included in the previous government response and are covered in this document. We received a large number of complex and detailed responses that have taken additional time to summarise. The relevant consultation proposals can be grouped into two sections:

1. The use of grid transmission of additional renewable energy in producing RFNBOs; and
2. changes to the level of reward for biohydrogen.

The 2021 consultation saw 120 responses from a range of organisations concerning the government’s proposals.

The following table provides a breakdown of the different respondents to the RFNBO chapter of the consultation. 93 respondents answered at least one question on RFNBOs or hydrogen with a wide distribution of interest across the fuels and energy sectors.

Organisation Type	**RFNBO/hydrogen response**
Academic/research	1
Airport operator	1
Consultancy	10

Energy producer/distributer	7
Equipment manufacturer	3
Fossil fuel supplier/producer	8
Government agency	0
Grain Merchant	0
Lighthouse Authority	0
Non-governmental organisation	2
Port authority	1
Port operator	1
Renewable fuel supplier/producer	42
Representative body	12
Road haulage	1
Trader/investor	4
Grand Total	**93**

We would like to thank all stakeholders for their time and contribution in responding to the consultation. In developing the government response and final amendments to the RTFO, we have carefully considered all responses and the evidence provided.

Summary of proposals and government decisions

The use of grid transmission of additional renewable energy in producing RFNBOs

Proposals

The consultation asked eight questions to support our decision making and included the following broad proposals:

- How to define the principles of additionality for electricity used in RFNBO production for the RTFO;
- Whether and how to offer more flexibility in locating electrolysers by providing for ways to demonstrate renewability and additionality of electricity transmitted over a grid; and
- Whether and how to adjust the potential area to consider when calculating the GHG intensity of a grid, when not supplied by wholly additional electricity.

These proposals were designed to offer greater flexibility to RFNBO producers by opening up different pathways to either prove the renewable electricity used for production complied with the additionality principles, or that regional grids could be considered when assessing the overall GHG intensity of the electricity.

Government response summary

After assessing the responses to the consultation, we can confirm we intend to proceed with implementing the proposals broadly as set out in the original consultation with feedback via the consultation been particularly useful in ensuring the guidance has been developed as clearly as possible.

As proposed in the consultation, a definition of “additionality” will be included in an amendment to the 2007 RTFO Order. This will be supported by detailed guidance that will cover how the principles of additionality could be applied to different scenarios. This will include guidance on the use of power purchase agreements (PPAs) to transmit additional renewable electricity over the grid and how transmission losses can be accounted for. There will also be a requirement for a 30-minute temporal correlation to be demonstrated between renewable energy generation and electricity use or storage for RFNBO production.

The guidance will also set out scenarios where regional, non-national grid carbon intensities may be used to demonstrate a RFNBO meets the RTFOs required GHG emissions reduction threshold.

Because these changes generally relate to how the RTFO Administrator implements existing requirements within the 2007 RTFO Regulations (the Regulations) they will begin to be applied immediately where applications for Renewable Transport Fuel Certificates (RTFCs) are made. Detailed guidance is published alongside this response by the RTFO Administrator to support RFNBO producers in making these applications. To further support this change in approach we are beginning the parliamentary process to amend the Regulations to introduce an explicit reference to additionality. Subject to parliamentary procedure we expect these amendments to come into force later in 2022.

Changes to the level of reward for biohydrogen

Proposals

To date all biohydrogen submitted for RTFO support has been eligible for development fuel renewable transport fuel certificates (dRTFCs). The consultation proposed that where hydrogen is produced via reformation of biomethane, which use waste feedstocks to produce biomethane via anaerobic digestion for conversion into hydogen, eligibility for dRTFCs would be limited to scenarios where production was accompanied by carbon capture and storage (CCS). It was proposed that where biomethane reformation is employed without such additional CCS, the fuel would be reclassified such that it would only be eligible for standard RTFCs.

Government response summary

We can confirm we will proceed with reclassifying hydrogen produced from biomethane reformation without substantial CCS to be eligible for standard RTFCs only. Where substantial CCS is employed in the production of biohydrogen the fuel will remain eligible for dRTFCs.[3] In all cases the fuel still needs to meet the wider RTFO eligibility criteria. Implementing this amendment requires an amendment to the Regulations. We will initiate the parliamentary process shortly and, subject to completion, Subject to parliamentary approval, regulatory changes will apply from 1 January 2023. Draft guidance on how this will be applied, including how to demonstrate the CCS element for development fuel

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[3] All qualifying RFNBO hydrogen will remain eligible for dRTFCs.

claims, is to be published alongside the statutory instrument which will implement the changes.

Next steps

The change in approach relating to additionality and regional grids can be taken forward within the current drafting of the Renewable Transport Fuel Obligations Order 2007. This means the Administrator will consider applications against these updated criteria from the publication of this document. The Administrator has published detailed guidance alongside this document to aid applications for dRTFCs in respect of RFNBOs.

To further support the principles of additionality, we will also introduce an amendment to the Renewable Transport Fuel Obligations Order 2007 to include a definition of additionality. Subject to parliamentary approval this will come into force during 2022.

The amendment to the Renewable Transport Fuel Obligations Order 2007 will also include the required provisions to reclassify biohydrogen not produced with CCS. Subject to parliamentary approval, these provisions will come into force from 1 January 2023. Draft guidance will be published alongside the statutory instrument implementing these changes. A final version of the guidance will be published ahead of the relevant changes coming into effect at the start of the 2023 RTFO year, subject to parliamentary process.

2. The use of grid transmission of additional renewable energy in producing renewable fuels of non-biological origin (RFNBO)

Background

The RTFO has supported RFNBOs since 2018 with renewable hydrogen being eligible for development fuel RTFCs. To be awarded under the RTFO, renewable hydrogen must be produced from dedicated renewable energy generation.

It is an important principle of the scheme that in providing incentives for the production of renewable hydrogen we do not cause emissions to increase in other sectors. The central issue is if existing renewable energy generation is used to make fuels, that energy is no longer available to the national grid. It is then likely that fossil powered generation replaces the diverted renewable energy, leading to increased GHG emissions.

To avoid this fossil fuel substitution risk, we included the concept of additionality in the RTFO in 2018. This requires fuel producers to demonstrate that the renewable energy used to produce fuel was additional to that needed to serve existing national energy requirements. The current approach for verifying additionality (set out in guidance) means in practical terms only hydrogen produced from direct connections to dedicated renewable energy generation regularly qualify for support under the RTFO.

However, we understand that the existing implementation of additionality is more restrictive than necessary. We have therefore consulted on a range of proposals that would increase flexibility for RFNBO producers whilst still adhering to the wider concept of additionality. The increased flexibility would then still ensure fuel production delivers carbon savings when viewed across the energy supply spectrum.

A full summary of the rationale underpinning these policy proposals is available in the original consultation document published in March 2020[4]. The consultation sought views on a range of factors that the Administrator could consider when determining eligibility for the RTFO.

Summary of proposals

The following are the broad proposed changes in approach to the eligibility of RFNBO production that we consulted on:

- Establishing a definition for "additional renewable energy" and setting this as a benchmark for RTFO eligibility where specific energy is being assigned.

- Providing for the use of power purchase agreements (PPAs) or similar contractual arrangements to transmit additional renewable energy over the grid – rather than only via direct connection. This included:

    - To have the option to take account of transmission losses of energy when using contractual relationships like PPAs; and

    - To expect a 30-minute synchronisation period for renewable energy transmitted under contractual relationships like PPAs

- Allowing consideration of the carbon intensity of regional grids at a non-national level in assessing eligibility criteria for RFNBO production.

Questions and government response

Q11. Is "renewable energy that would not have been available to the grid in the absence of power demand from the RFNBO plant in question" an appropriate definition of additional renewable energy?

Summary of responses

Total	Yes	No
71	44	27

Around two thirds agreed with the proposed definition of additional renewable energy, whilst one third did not agree. A number of respondents that either agreed or disagreed had suggestions of how the definition could be improved or how it should be administered. As such, there was significant cross over in the themes of comments for those selecting either 'yes' or 'no' to this question.

[4] https://www.gov.uk/government/consultations/amending-the-renewable-transport-fuels-obligation-rtfo-to-increase-carbon-savings-on-land-air-and-at-sea

Many of those agreeing and disagreeing with the definition cited administrative considerations that would need to be addressed by the RTFO Administrator. Six of the respondents stressed that the implementation would have to be sufficiently flexibly implemented to ensure compliance could be achieved. Concerns were raised that any evidential requirements would need to be sufficiently robust to ensure they avoid misallocation and double counting of renewable energy.
Three respondents raised concerns that additionality would result in a “double-subsidy” situation with payment both for the generation of renewable electricity and a further payment for the converted electricity as a renewable fuel.

It was proposed that the definition put forward in the consultation could be amended to be more effective to ensure the principles of additionality can be maintained, with several suggestions received. Concern was raised by one respondent that the definition may be too narrow, resulting in only renewable sources that were both grid-connected and curtailed meeting the definition. Three respondents were concerned it would be too difficult to both comply and evidence compliance with the principles of additionality. It was raised that the barriers imposed by the definition could restrict investment in both renewable energy and RFNBO production facilities.

Of those who disagreed with the proposed definition of additionality, four respondents argued that implementing such a concept was the wrong approach. They suggested the market would balance out the demand for renewables, so there is no need to ensure energy is additional. One respondent suggested that rather than needing to demonstrate that energy is additional, we should build compliance around periods of low renewable energy price bands, which would demonstrate periods of excess energy supply. One respondent also suggested that we should limit eligibility to projects with common ownership of the whole system from generation to fuel production, however it was not clear if they were referring to directly connected assets or generation and production connected via the grid.

Two respondents suggested that additionality should apply to renewable generation sites that have their operating life extended for the purpose of providing power to a RFNBO production site. One respondent requested that additionality should be able to apply to renewable energy storage.

Two respondents either asked for grandfathering or first-of-a-kind exemptions. The effect being that novel facilities would be able to use non-additional conditions into the future, with some phase out of this requirement over time.

A theme that ran through many of the responses to this question was that the proposed definition should be backed up by further and more detailed guidance.

Government Response

While the proposed definition of additionality was broadly supported, we acknowledge this needs to be accompanied by detailed guidance that can account for different situations. Guidance has been published alongside this document, detailing the additionality requirements, and providing further information on many of the points and scenarios raised. The guidance comes into effect immediately and will be later supported by legislation.

It is important to note that the changes in relation to additionality of renewable energy are a relaxing of our current interpretation of qualifying scenarios. Therefore, we expect existing eligible scenarios will remain eligible after the change of interpretation.

We believe that the proposed definition of 'additionality' provides the best basis for that guidance and we will continue to work with industry to ensure the evidential requirements can be appropriately met by RFNBO producers. We understand that while this definition does open further avenues for the production of RFNBOs, it remains more restrictive than some have called for. This is important as diverting renewable power from grid supply would reduce the overall GHG emissions savings RFNBOs can deliver. As the RTFO has a statutory obligation to decarbonise transport fuels this risks failing on that duty.

We can confirm that both life extended renewable generation and renewable energy storage facilities could be considered under the additionality principles provided the relevant further criteria, as set out in the guidance, are met. RFNBOs produced by non-grid connected/off-grid facilities can also qualify for dRTFCs.

In relation to concerns around "double subsidy" obtained through claiming from both renewable electricity schemes and the RTFO, we can confirm the energy would have in effect been subsidised twice, however the fuel is only supported once. This is consistent with the current policy which prevents "double subsidy" of the fuel. If we were to extend this to prevent double support to the energy, all Renewable Obligation or Contract for Difference accredited energy sources would be excluded. This would prevent any existing or grid connected facilities providing energy for RFNBO production even under additional conditions.

We do not agree with the suggestions to use low renewable energy price bands as a metric to demonstrate excess energy. This is because it would provide inadequate verification that the energy is both renewable and excess to grid demand. However, there is an argument that systems like the balancing mechanism could be used as part of an additionality verification process. The guidance remains sufficiently broad to allow this type of evidence to be submitted however it cannot be confirmed that this alone would satisfy the sustainability requirements of the RTFO. Each application will be assessed on a case-by-case basis.

The requests for grandfathering and similar provisions, such as phasing in of provisions or commitments to support periods, will not be taken forward. This is inconsistent with the way the RTFO currently operates and is administered. We also believe this request is redundant considering the wider changes set out in this document and accompanying guidance, which provide sufficient flexibility for RFNBO producers.

Q12. Should the Administrator be able to take into account the use of power purchase agreements (PPAs) as evidence that suppliers have purchased additional renewable energy in order to allow the renewable power generation to be located in a separate location from the RFNBO production facility?

Summary of responses

Total	Yes	No
69	59	10

The proposal to allow the use of PPAs for evidencing compliance with RTFO RFNBO sustainability requirements was supported by most respondents. One of the most common comments surrounded the need to retire renewable energy guarantees of origin (REGOs) associated with the supplied energy or to otherwise ensure the carbon savings are only accounted for once. This was raised by sixteen respondents including those in favour and opposed to the proposal. Connected to this, ten respondents felt that the Administrator should require additional supporting evidence beyond just a PPA to verify the renewable origin and GHG assessment of the energy. This was linked to a desire for close temporal correlation between the energy generation and RFNBO production.

Nine respondents requested extra detail on the proposals including the specific parameters around the structure of PPAs that would be accepted. Individual respondents suggested proposals around the necessary attributes of PPA relationships. These included requiring the PPA to match the complete life cycle of the project and/or include geographical restrictions. There were also requests that the agreements should undergo regular verification to ensure the production remained as sustainable as possible.

Linked to PPA queries, one respondent asked that excess energy be permitted to be resold rather than wasted. One also implied that nuclear energy be considered as an input.

Concern was raised that vertically integrated entities, such as major power producers, could distort the PPA market, keeping additional generation for their own RFNBO production and thereby preventing non-integrated hydrogen producers from accessing appropriate PPAs. It was also raised that due to differences in the application of the energy market in Northern Ireland certain PPAs would not be suitable under these proposals.

One respondent suggested that the proposal would only be viable if the electricity generation and the RFNBO production facilities were both owned by the same entity.

Three respondents felt that PPAs were appropriate for direct supply of electric vehicles but not RFNBO production. Another felt that only direct-wire renewables[5] should be eligible for RFNBO production under the RTFO.

One respondent asked for a change to the principle of the RTFO to allow energy balancing between different fuel types.

Five respondents felt that the use of PPAs should be allowed to prove the renewable origins and additionality for energy used in all types of fuel production, not just RFNBOs.

Government response

We intend to permit the use of PPAs and similar contractual arrangements as a form of evidence in demonstrating the additionality and renewable origins of energy used in

[5] Where the renewable generation is linked physically to the RFNBO production by a privately allocated wire.

RFNBO production. This change comes into effect immediately as it is implemented via the updated guidance published alongside this document. The change in approach will be further supported via an amendment to the 2007 RTFO Order as soon as parliamentary time allows. This legislative change will formalise the principles around grid transmission and the powers for the Administrator to calculate GHG intensities. The definitions and processes around the requirements for PPAs are set out in the accompanying guidance. This means the RTFO Administrator will retain flexibility in their administration of the scheme, this flexibility is important for the scheme as it relates to an innovative and evolving industry.

The guidance around the use of PPAs includes a requirement for clear evidence of the transfer or retirement of REGOs associated with the production of the renewable energy involved. This was not specifically proposed in the consultation as it is only relevant to UK production and would complicate verifying imported RFNBOs if only UK methods of operation were covered. The REGO system allows for the separation of the sale of renewability from the sale for energy. Countries without a REGO like mechanism generally do not allow for separating the sale of renewability from the sale of energy, and so a similar evidential requirement would not be necessary.

We can confirm that where a RFNBO producer has more contracted energy than their immediate needs for production, any resale of this on the open market is not relevant to the verification processes of fuel under the RTFO.

In relation to the concerns raised relating to the double counting of carbon savings, we are comfortable that our adopted proposals and existing processes will prevent this. Where renewable electricity is generated the carbon saving is allocated to the energy sector, where that electricity is used to produce a transport fuel that carbon savings is not claimed again in transport. The outcome is that where RFNBOs are produced the carbon saving is always attributed in the energy sector. This is the same method as for EVs and is consistent across BEIS and DfT accounting. The risk of double counting is only relevant if a fuel exporter were to use a non-UNFCCC[6] compatible method of carbon accounting. This would be mitigated by the verification process undertaken by the RTFO Administrator.

We acknowledge the concerns that vertically integrated entities may be well placed to utilise the changes relating to additional energy. However, looking across the changes we are taking forward we are confident this represents a significantly improved position for all renewable hydrogen producers compared to the current environment.

With respect to requests in relation to Northern Ireland, it is not possible to treat one area of the UK differently from the rest, or differently to other countries more generally. All the rules and requirements of the RTFO can generally be applied equally to anywhere in the world. This is important to ensure the scheme complies with global trade rules.

In relation to suggestions that both the generation and fuel production facilities be required to be co-owned, or that only direct-wire connections should be permitted, we believe these measures would be overly restrictive. The wider guidance on additionality will ensure potential carbon savings are maximised with necessary barriers at a minimum.

[6] United Nation Framework Convention on Climate Change

Some suggestions received were outside the scope of the consultation. These included offering energy balancing across different fuels or the use of nuclear energy as an input. These are not consistent with current RTFO requirements. Firstly, all fuel claimed for must be that which is used in transport. Secondly, such fuel must be produced using renewable feedstocks and energy sources recognised in the Energy Act (2004). The suggestion that PPAs should be able to reduce the GHG intensity of other forms of fuel, or be restricted to EV charging, were also outside the scope of the consultation and so will not be addressed here. We welcome further engagement on these points via officials in the Low Carbon Fuels team, a contact email address is provided at the end of this document.

Q13. A consequence of allowing the use of PPAs to demonstrate renewability, in combination with also permitting other suppliers to use a grid average renewability, is that the same renewable energy could be accounted for more than once. We consider this to be low risk when hydrogen energy and other RFNBO demand is small compared to the total renewable energy available on the grid. We are seeking views on whether this risk is acceptable. Is this risk acceptable?

Summary of responses

Total	Yes	No
57	43	14

Three quarters of respondents agreed that the risks of duplicated renewable electricity accounting were low, however a broad range of opinions were stated across the responses.

Six respondents felt that keeping the general policy and how it is administered under regular review would manage the risk adequately. Five respondents felt that whilst the proposal had manageable risks, in the future it would be desirable to move from the use of PPAs to the use of fuel mix disclosures, REGOs or other proofs of carbon intensity and energy correlation. In addition, nine respondents, both for and against, stated that the carbon savings should be linked to the electricity used and not then be available for sale separately as a fuel. Two respondents agreed that the enforcement of the principles underlying the RTFO would manage the risks of double counting adequately. Two further respondents felt that the risk was manageable whilst the use of PPAs for RFNBO production was below 5% of grid capacity or the deployment of electrolysers outpaces the deployment of renewables. One respondent argued the roll out of more electrolysers would help balance the grid load and capture more renewable energy than is currently utilised.

Four respondents, including both for and against, felt that energy provided under a PPA for the RFNBO production should be excluded from the grid mix calculations, or that the use of PPAs for transport would distort the indirect (Scope 2) emissions calculations in international carbon accounting and corporate reports. We were also asked by one respondent to work with BEIS on these questions.

One respondent that disagreed felt that the use of grid averages should only be allowed where there is a sufficiently low local GHG intensity. This subject is covered in the summary of questions 16 and 17.

One respondent that agreed with the proposal to allow the use of PPAs and was content with the risk of double counting, stated these requirements would cease to be relevant with the future decarbonisation of electricity grids. In this respect, at some point grid based RFNBO production will meet the RTFOs GHG saving thresholds.

A number of respondents made representations similar to that as for previous questions. These generally requested more flexibility within the wider additionality principles and advocating the use of REGOs or equivalent to demonstrate proof of carbon savings.

Two respondents requested more detail on how the proposals would work.

Government response

We are reassured by the responses to this consultation question and do not see a significant risk of the double counting of renewable energy. This is largely because of the robust nature of carbon accounting standards which segregates energy and transport systems and prevents double counting. We will therefore proceed with the consultation proposals. The main concerns raised around this question were associated with verifying sustainability. The risk involved in double counting is primarily around fuels imported from nations not using international UNFCCC guidelines on carbon accounting. Alternatively, there is also the issue of hidden reallocation of the renewability associated with power, which could constitute fraud. As with previous questions these are dealt with in the accompanying guidance as the solutions and mitigations are linked to verification of PPAs.

In relation to concerns around the pace of installation of electrolysers and new renewable generation, we acknowledge that new electrolysers will generally need to be paired to new renewable production or use curtailed generation. From an RTFO perspective this scenario will be self-limiting.

The guidance provides further detail on how different scenarios can be interpreted. The RTFO Administrator is also able to aid suppliers with specific eligibility queries.

The nature of the proposal that PPAs would be permitted as a part of the verification of renewability and carbon intensity means that other supporting information sources, such as REGOs, are still expected to be a part of any assessment system. Proposals to shift to a REGO or similar guarantee of origin (GOO) only system have several significant issues. Such a system is only “paper based” meaning the temporal and energy resolution of these certificates is insufficient for accurately demonstrating additionality. A single 1MW/h REGO would be sufficient to power the hydrogen production of a small-scale electrolyser for multiple weeks, this would therefore not provide the level of detail required to satisfy the principles of additionality in the RTFO. REGOs or GOOs are also generally only available to UK or EU producers. Fuels imported from outside of these markets do not necessarily have a comparable system, and the systems do not tend to support renewability being traded independently of the energy. It is essential that any RTFO system of verification works for domestic and imported fuels. Further detail around the administration of this is covered in the guidance. The RTFO Administrator will also engage with suppliers on specific cases in line with the duty of the Administrator.

Concerning the grid mix calculations, the methodology for energy sector emissions calculations is beyond the remit of this consultation. The nature of PPAs and the current methodologies in place mean that energy transmitted via a PPA will count toward grid decarbonisation and the resulting energy and carbon savings not allocated to transport. The risk of indirect (scope 2) emissions being distorted with respect to imported RFNBOs, where there might be a risk of misallocation in the country of origin, could be considered real and is something that should be kept under observation. This should be a very low risk however if countries are adhering to the UNFCCC standards on reporting. The RTFO administrator will require evidence that any fuel consignments will have to comply with stated standards. We continue to work closely with BEIS to ensure RTFO supported RFNBOs align with wider UK policy on hydrogen, carbon accounting and other elements of the energy system.

Addressing the argument that these rules will cease to be relevant once the UK grid is sufficiently decarbonised, we agree, and see requirements around PPAs as additional pathways until such time. We would also point out that this applies to any electricity grid and not just the UK national grid. Two negative respondents felt that there should be no use of grid averages, with only PPAs permitted for RFNBO production. We can confirm that these options are intended to be complementary, not additive. Generally, the grid average methodology would be used in the absence of a PPA or similar arrangement to demonstrate additionality. Currently, the use of most national grid averages would not meet the minimum GHG savings required for RTFO eligibility.

Q14. Should appropriate adjustments be made to the amount of renewable energy supplied to a RFNBO production facility to account for transmission losses where renewable energy is transferred over the electricity grid?

Summary of responses

Total	Yes	No
60	39	21

Around two thirds agreed, with the remainder opposed to the use transmission losses in our proposals.

Eight respondents felt that accounting for losses in some form was essential to maintaining a level playing field with gas. They explained that under the RTFO renewable gas injected into the grid uses a mass balance process but must account for resulting losses. Direct connections, with no equivalent losses, benefit from the improved efficiency of their production plants.

Five respondents felt that the rule would encourage locating production into areas where it can minimise losses and that this would also help drive improvements in the efficiency of the layout of the transmission system. However, one respondent suggested the opposite, in that having the losses accounted for at the point of RFNBO production would not encourage transmission system improvements.

There was a wide range of suggestions for the level of correction for transmission losses. Ten respondents advocated a mixture of average and exact transmission losses due to uncertainty and variability under different geographical and use conditions. One stated that because accounting for losses does not form a part of other renewable energy systems around the world, it should not be a part of the RTFO accounting.

Some respondents were in opposition to accounting for transmission losses in grid transmitted energy. Within them, five energy companies argued that the standard PPA mechanisms account for losses and socialise them across the grid, whilst another four argued that matched metering at producers and users will already account for these losses. Five respondents argued that the grid charges in place provide price signals to encourage spatial alignment, so this is an existing mitigation. Three respondents felt that the impact of these losses will be too small to consider and/or too variable for practical tracking. Several respondents reiterated their general call for simplicity of implementation.

One respondent requested early-stage market support focussed on hydrogen while another requested that BEIS and DfT remove non-commodity grid charges for RFNBO producers.

Two respondents raised that there should also be tracking of the transmission losses of finished hydrogen, in line with what is done for biomethane already. Three respondents suggested that transmission losses are not factored in for biomethane and so should not be included for energy.

Government response

Having reviewed the responses to this question we remain assured that having the option of addressing potential grid losses is appropriate and so will proceed with this approach. We will use the default figure consulted on (9% transmission losses), unless there are specific metering data provided. This will be implemented primarily through methodologies set out in the guidance.

This is consistent with the existing implementation of the RTFO, where transmission losses and their GHG potential are considered for the Life Cycle Analysis (LCA) for all fuels. We can confirm that losses across a gas grid are already required to be included in all LCAs for biomethane transmission. Additionally, transmission losses for hydrogen distribution are captured as the RTFO only supports fuel supplied into transport.

We agree that if a correction for transmission losses optimises RFNBO layouts to reduce loss and pressure on energy grids this is a positive outcome. We doubt that having the RFNBO producer account for the correct amount of energy in the process will have a significant negative impact on deployment.

Several respondents identified various contexts where the use of transmission losses is dealt with by the nature of either metering or existing contracts. We agree that it is reasonable to consider presentation of actual data to replace default or calculated values, and this is reflected in the guidance.

With regard to the non-commodity grid charges, we do not agree that these charges mitigate the fact that renewable energy will be lost in transmission across an energy grid. Such charges should therefore not be used to mitigate the loss between the generator and user of the energy.

The rationale for including transmission losses is linked to the need to deliver measurable and accurate carbon savings. It is not intended as a driver for price signals around the location of generation and production. Similarly, the existence of charges to socialise the grid costs of the extra supply does not mitigate for the loss of energy in the system and the impact that would have on the carbon intensity of a RFNBO produced from the resulting energy.

Q15. Do you have any comments on the proposal to use a 30-minute time period for temporal correlation of renewable energy production and use?

Summary of responses

Total	Yes	No
50	34	16

We received a wide range of comments on our proposal to use a 30-minute period for temporal correlation of renewable energy production and use. The table above summarises the split in overall opinion.

Nine of the respondents were positive because they felt that the use of the proposed 30-minute temporal correlation protects the principle of additionality and avoids "paper only" transfer of renewability. They confirmed that existing metering systems were able to support this level of temporal resolution. Eight responses suggested that the rules should support the storage of additional energy to allow for situations such as day/night buffering or production of RFNBOs when there is a low wind and overcast day. Counter to this, a research agency responded with the opposite position on storage of energy prior to use (i.e., storage shouldn't be permitted), on the basis that they felt it would be preferable to supply this to the grid.

One respondent raised the concern that the 30-minute proposal puts increased risk on the RFNBO producer. The challenge of securing energy at this temporal resolution would likely shift investment costs towards installing specific generation capacity, therefore increasing costs overall. Three respondents felt that either the synchronisation should be relaxed to allow RFNBO producers to be rewarded for production when operating as a grid balancing load[7] or that the system explicitly prevented this as it is proposed. This is also connected to a concern raised by an energy company as to how long this method will remain relevant to the UK grid as it decarbonises.

Five respondents suggested that requiring synchronisation would lead to more frequent shutdowns of electrolysers resulting in more wear and higher failure rates.

One respondent was concerned that the availability of even a 30-minute synchronisation period would not ensure all qualifying renewable fuel was produced from additional energy. Two respondents felt that the need for synchronisation would be counter to the most efficient planning of renewable generation installation across the grid, and that this would also increase costs.

[7] A process used to add extra demand to an electricity grid where there is more energy supplied than is otherwise being used. It has the effect of maintaining a consistent level of energy generation and stabilising effect on grid voltages.

Those asking for more flexibility included six respondents that requested a 1 month, rather than 30-minute, synchronisation period as is provided by the California Air Resources Board (CARB). Three more asked that there be a phase in of synchronisation requirements, for example beginning at 1 month and reducing to 24hrs over time. Three respondents asked that the synchronisation element be phased in over multiple years, to allow them to adapt to the requirements. One asked that the reconciliation process be linked to the quarterly reconciliation of a typical PPA contract, however it was not clear if they meant this to be the synchronisation period.

Thirteen respondents, across a range of businesses, felt that the temporal synchronisation would have an impact on costs and administrative complexity. One respondent asked for the ability to transfer renewability independent of energy. This is referred to as “paper only” renewable energy transfer.

As covered in responses to previous questions, two asked that REGOs alone be used as evidence for renewable energy. One respondent asked specifically for virtual and portfolio[8] PPAs to be considered in the evidence for qualifying renewable energy. Lastly one respondent suggested that the balancing market and day ahead market might provide suitable evidence of synchronisation and renewability.

Government response

Following the comments received, we remain of the view that the 30-minute synchronisation requirement is appropriate to ensure the principles of non-diversion and accountability of renewable energy. This is initially set out in the guidance published alongside this document. Later in 2022 we will update legislation to include a definition of additionality that will reference the 30-minute synchronisation requirement.

The requests for the inclusion/allowance of energy storage in the context of temporal correlation is consistent with the principles we have set out, provided the energy being stored was additional renewable energy when generated.

While we accept that the 30-minute synchronisation requirement is not risk free for RFNBO producers, we must balance these risks with the need for real and measurable carbon savings. We do not agree with the proposals to phase in, or progressively tighten any temporal synchronisation requirements. The incoming changes are a significant relaxation of the pre-existing rules regarding renewable hydrogen production which we feel strike the correct balance. The respondent effectively proposed to completely remove all restrictions and then reintroduce them to a lesser degree over a phase in period, this is unworkable and irrational.

Most hydrogen is expected to be supplied domestically in the UK, in this case any relaxation beyond the 30-minute synchronisation would likely result in the GHG intensity of the hydrogen supplied slipping to that delivered by the grid average. Such a scenario would deliver a GHG intensity at the vehicle of roughly twice that of diesel, this would not achieve the RTFO duty to reduce GHG emissions. Conversely, under the 30-minute

[8] Both virtual and Portfolio PPAs are contractual arrangements that link more than one renewable generation facility at a time to a RFNBO plant.

requirement we anticipate a GHG intensity of close to zero which will be more accurate and continue to support the RTFO's duties. Direct metering and energy supply trading systems can determine power production and usage levels over 30-minute intervals.

Many respondents that were opposed to the 30-minute requirement did so on the basis that it does not fit closely with existing contractual arrangements on the energy grid. While we understand this, for the reasons given above, we believe that the 30-minute requirement is important to maintaining carbon savings. The 30-minute synchronisation requirement also minimises the risk that energy is transferred in a way that is "paper only" and not physically attributable to a clear renewable origin.

While there is no reason that a grid balancing service reward could not be made available to electrolysers which are also producing fuel under the RTFO, such a scenario would not automatically prove additionality. If a clear case can be made that the energy, or some proportion of the energy, used in this process is renewable and additional, then that proportion may be eligible for RTFO support. However, this is not likely to be a blanket condition for all cases as in some cases there may be no support for extending renewable generation. The RTFO Administrator will continue to be responsible for supporting applications and helping develop ways to approach new fuel pathways, however grid balancing policy itself is beyond the remit of this consultation.

Whilst the changes relating to energy synchronisation are intended to ensure high sustainability RFNBO production in current conditions, we anticipate that they are a transitionary measure to allow routes to achieve GHG compliance until the UK grid (or other national/regional grid) can become sufficiently decarbonised for conventional connections.

We recognise that different types of electrolysers are suited to different types of application. While the 30-minute synchronisation requirement may mean electrolysers need to ramp production up and down rapidly, certain technologies can accommodate this type of operation. Conversely, electrolysers less suited to such scenarios may be better used via direct connection, virtual PPAs or within suitable regional grids. The multiple RTFO eligibility options covered by this consultation should allow different types of electrolysers to be used where best suited.

Q16. Should the Administrator be able to permit fuel suppliers to use local grid GHG emissions factors in RFNBO GHG emission calculations? Circumstances in which this might be appropriate include where there are local grid constraints or other local conditions which mean that the local grid GHG intensity differs substantially from that of the national grid.

Summary of responses

Total	Yes	No
61	45	16

The option of using local grid GHG intensities was widely supported, and many respondents offered constructive ideas and evidence within their responses.

As was common to many of the questions, one of the first requests of several respondents was for extra detail as to how regional or sub-grids are to be interpreted. Four respondents stressed that any decision to classify a grid as regional be based on robust information both in terms of its interconnection and GHG intensity. Three respondents asked that the proposals be specifically applied to islands immediately and then expanded to allow for wider types of regional grids. Similarly, one asked that the DfT be pragmatic and work with BEIS and National Grid, among others on this kind of proposal, whilst another requested that we also consider scenarios outside the UK.

Four respondents asked that the regional grid GHG intensity was aggregated half-hourly instead of annually. Three more suggested that the impacts of this policy should be constantly reviewed, because they were concerned about its potential impact. One asked that any REGOs be retired to account for this grid mix to prevent double counting. One respondent asked that this policy should not be used in preference to full accounting as provided by direct connections or PPAs. A further respondent suggested that this option could encourage RFNBO facilities to locate production in certain areas to benefit from the regional grid classification.

One respondent asked that the carbon intensities be updated as the grid decarbonised. In contrast another asked that any eligibility be attached to facilities for a fixed period from application for RTFC support, e.g., 10 years. It was also requested that these calculations be permitted for biofuel producers as well. This is not how the RTFO is designed as the fuel is assessed not the facility and each consignment must be eligible for support.

Three felt that these proposals would create regional imbalances in the investment in RFNBOs. One of these respondents also suggested that the regional grids would create a tension with PPA mechanisms and could cause mis-location of RFNBO production. An energy company repeated their point that these measures would only be relevant in the UK until the grid is sufficiently decarbonised. In contrast another energy company felt that the GHG intensity of grids should only be calculated at a national scale.

An energy company argued that the higher carbon intensity of urban areas would mean that RFNBO producers would be deterred from locating near cities, whereas a different energy company felt that only real time regional data should be used for GHG intensity calculations. A renewable fuel producer felt that there would be great difficulty in proving regional GHG intensity figures.

One respondent argued that a market-based method should be used to incentivise renewable generation and not to consider regional grid intensities. An NGO argued that there should be policies to increase grid connectedness rather than recognising differences and that the UK should replicate EU rules on this topic.

Government response

We have adopted the proposal allowing the Administrator to treat electricity grids on a regional scale rather than limiting the calculations to a national level only. These changes are initially implemented through the guidance published alongside this consultation. Later in 2022 we will introduce amendments to the RTFO Regulations which will include provision for grid GHG intensities to be calculated based on either a national or regional basis. The methodology underpinning this will remain at the discretion of the Administrator to ensure flexibility can be retained, the approach to applying this can be found in the accompanying guidance.

Our aim with this change is to reflect the real conditions of the electricity grids, which supply RFNBO production facilities. This provides a fairer assessment in places such as the Orkney Islands as well other areas that can demonstrate suitable regional grid characteristics.

Consistent with other areas in our proposals there was a request for more explicit detail on the nature of carbon intensities and the regional definitions of energy grids. This detail is set out in the guidance and can be summarised as follows - The Administrator would need to be satisfied that the grid either:

- be physically separate from the main national grid,
- be managed as if it were physically separate, or
- that there is in place some system which prevents generated electricity supplied into the sub-grid from being supplied to the wider grid.

If the Administrator deems any of the above criteria have been met, the carbon intensity of the sub-grid can be used in assessing whether the RFNBO qualifies for RTFO support. The percentage renewability of the regional grid would then be used when apportioning any fuel that can claim dRTFCs.

These proposals were formed to deal with a range of different grid systems and are designed to be flexible. To ensure the practical implementation of the requirements we will, wherever possible, coordinate and refine our approach in conjunction with BEIS and other energy related agencies. The approach will be kept under review to ensure it remains appropriate.

In relation to double counting, and grid mix calculations, any REGOs being used to verify the transmission of power must be retired. This mirrors the approach taken for national scale grids, and in permitting smaller regions to be considered separately, a fairer assessment can be made in certain circumstances. We do not see this policy providing special treatment to specific areas, but that it increases the ability to report accurate carbon savings in those areas.

We can also confirm that in the UK, where electricity is used to produce RFNBOs, it has its carbon emissions accounted for under the energy system and not transport. This applies equally to regional grids. This mitigates the risk of double counting carbon savings. We will continue to use grid carbon intensity based on data from two years previously, or the most recent available year. Changing this to live data would require further consideration and may not be suitable in all regions at this time. This policy will be kept under review.

As any grid decarbonises, the change in the regional or national GHG intensity would be reflected in the calculations used in the assessment of fuel consignments. This is in line with the current implementation of the RTFO. The RTFO does not allocate certificates on a facility basis but on a fuel consignment basis. This means any qualifying fuel will be able to receive support. For these reasons, it is not possible to guarantee a production facility's qualification for a fixed period.

Several respondents were concerned that our proposals would have knock on impacts for the support of renewable generation and wider grid issues. These areas are beyond the scope of these changes to the RTFO. However, we recognise the indirect impact that the

RTFO regulations can have on parallel industries. We will continue to work closely with colleagues across government departments to retain a balanced and joined up policy position.

Q17. A consequence of allowing local grid GHG emissions to be used in calculating the GHG intensity for a RFNBO is that GHG savings may be claimed by a production facility on a low GHG emission regional/local grid which have also been accounted for in the average national grid GHG intensity. Is this risk acceptable?

Summary of responses

Total	Yes	No
49	32	17

Most substantive responses agreed that the risk of double counting was low and therefore acceptable.

Seven felt that there was a manageable risk if the impact was reviewed when the number of electrolysers on the grid reached a meaningful level, while two suggested that the risks and relevance of the policy will reduce as grids decarbonise. One respondent felt that if reasonable steps were taken to avoid double counting the risks were manageable. Another felt these risks were generally low where the grids were clearly separate. One respondent argued that raising targets would mitigate the risks involved.

One respondent felt that this question highlights the need to have a policy for accounting for energy generation used in transport. Another stated that the proposal assumes electrolysers are operating in a steady state, which is not representative of Proton Exchange Membrane (PEM) electrolysers so these should be allowed to use instantaneous GHG intensities.

Points around assurance were raised by nine respondents with eight asking for assessment by the RTFO Administrator or an independent third party. The remaining responses returned to the need to retire REGOs when establishing the GHG figures of regional grids to avoid double counting.

A number of points were raised in relation to wider energy markets. One stated that most countries are trying to reduce the regional variation in energy grids. Another stated that using local GHG intensities may encourage RFNBO production in unsuitable places. In parallel to the above, an energy consultancy suggested the regionalisation of GHG intensity for this purpose would undermine “time of use tariffs” because RFNBO producers would cherry pick locations and tailor capacity based on potential subsidy.

Government response

The responses indicated a general agreement that the risks of double counting involved in this policy were manageable. As a result, we do not propose to alter our approach in this area. Further detail on how we will treat regional grids is provided in the published guidance.

As we have highlighted in previous questions, the risk of double counting is low in the UK due to the fact carbon savings from energy generation is apportioned to the energy sector even when eventual use is in a transport setting. If nations follow UNFCCC rules on carbon accounting this will hold true for imported RFNBOs.

In relation to the progressive decarbonising of energy grids, the wider RTFO rules already account for improvements in grid decarbonisation. The scheme is also kept under constant review, notwithstanding the statutory five yearly reviews that take place to assess the impact of legislative amendments.

The concern raised that the policy is based around steady state (alkaline) electrolyser usage, rather than faster switching (PEM) electrolysers is not correct. The policy mirrors the national scale rules at a more local level with the aim of delivering more accurate carbon intensities to producers in restricted decarbonised grids.

The most common request among the negative responses was to have a reliable method of assurance to mitigate the double counting risk from using grid connected average GHG intensity. The current policy requires that the GHG impact is assessed based on the average from a previous period, meaning this is not subject to double counting. Changing to match this request would be inconsistent with this existing position. In this case the value of the GHG intensity is derived from the average two years prior to the production, so this is likely to place a stronger limit on the claim of RTFCs from this type of connection than specifically allocated renewable energy, it also has no risk of double counting.

Additionally, to achieve the grid average value two years before the production, REGOs must have been retired with the energy suppliers, thus removing the perceived risk of double counting.

In relation to the comments on the regional variation in grid GHG intensities, this policy is designed to fit different circumstances rather than to influence a particular grid layout. We believe the risk that RFNBO producers will actively select regional grids to locate electrolysers is low. It may be simpler in some regions to set up with a grid connection but that is why we have also brought forward separate changes to facilitate RTFO RFNBO production where the grid does not meet a sufficiently low GHG intensity.

While electrolysers in such low carbon regional or national grid locations would be the simplest to implement, there are currently very few grids and sub-grids where the GHG intensity is sufficiently low to qualify. Where such a sub-grid is available, this policy will ensure RFNBOs produced there can be appropriately assessed. Due to the limited availability of these grids, we do not believe this will significantly outweigh the potential to secure additional power on larger national grids through the alternative options presented in this response. Producers using national grids but demonstrating compliance through either direct connections or additionality are currently likely to be able to generate more qualifying fuel and be more flexible in their location.

Q18. Have we captured all the additionality scenarios as set out in the proposals in the chapter and in the decision tree (Figure 13)? Please suggest alternatives with evidence

Summary of responses

Total	Yes	No
47	32	15

Many of the responses to this question were useful in highlighting how the guidance could be best tailored to ensure the proposals can be appropriately administered.

Several respondents asked for additional clarity and flexibility on how various additionality requirements could and should be evidenced. This included: synchronisation between construction and commissioning, evidence connected to proving synchronisation, curtailment, excess energy, qualification of stranded assets and the broader link between additionality and the 30-minute requirement.

There were several requests for additional clarity around how PPAs should be implemented and interpreted and the use of energy storage. We also received feedback relating to the decision tree outlined in the consultation. One respondent suggested it should be split into grid connected and off-grid installations while another asked that a further question be added on whether the energy source is supported by another policy instrument. There was also a request for clarity on what the term “inherent to the business plan” meant in relation to new generation capacity.

A biofuel producer proposed that the power draw should be assessed against the full power draw of the plant and transmission and distribution losses. A hydrogen producer proposed that curtailment should be defined as periods of extremely low or negative wholesale electricity prices. An energy producer suggested that life extension of an existing plant beyond its decommissioning target date be considered equivalent to “new” renewables. One respondent raised the concern that the proposals may not permit partial import of grid electricity where onsite generation is also a source.

In terms of wider comments on the principles and scope of additionality, a hydrogen producer stated that the circular economy should be explicitly covered by the amendments to the RTFO, particularly with regards to waste combustion for power. Five respondents including an oil producer, said that we should include biomass fuelled generators and plant as a valid energy source for making RFNBOs.

Comments were also received relating to wider grid connection considerations, including the benefits of frequency and load balancing services electrolysers offer. One respondent requested that we consider rewarding hydrogen production where that hydrogen is injected into the gas grid, with an energy balance approach to any gas then extracted for fuel use. Two respondents suggested that identifying and allocating excess energy is not possible due to the design of the energy market and the economic tools used. Lastly, a respondent also suggested that hydrogen should generally be rewarded based on its feedstocks not the means of production.

Government response

We thank respondents for their constructive comments that have helped improve how we present the concept of additionality within the guidance and in our implementation. One key improvement is that we have directly integrated the 30-minute temporal synchronisation requirement into the definition of additionality. This is outlined in the guidance and will be taken forward in our legislative amendments.

While the guidance published alongside this government response provides some detail and suggestions of how producers can comply with the different eligibility requirements for RFNBOS, it is not designed to be entirely prescriptive. While examples of the types of evidence that may be accepted are provided, we also welcome engagement on how more complex cases can meet the broader evidence requirements.

Regarding curtailed energy, we do not expect that there is only a single method to evidence this, as it will be different depending on grid and facility topology. We will openly look at methods that demonstrate a rigorous and reliable measure for curtailment. As stated in an answer to a previous question, it is possible that balancing market information can be used as a part of this evidence. There is also nothing in the principles outlined that would prevent stored energy from being used, provided the wider additionality requirements were met.

For paired installations we do not intend to place a fixed timeframe for a permitted difference between the commissioning dates of energy generation and RFNBO production. We accept there are likely to be unexpected factors leading to unpredictable commissioning dates for these facilities. As suggested in the consultation, we would expect evidence and early engagement from the prospective supplier to ensure we understand the relationship between the facilities with the RTFO administrator. This in line with the current development fuels approval process. However, we can be clear that a separation in time which causes the planning permission for one or other of the components to lapse would breach a fundamental principle of the paired relationship.

We do not agree that additional clarity would be achieved by separating our decision tree into grid connected and directly connected elements. We believe the guidance is clear in how these different types are assessed.

In terms of questions over the types of PPAs allowed, we are not intending to be prescriptive on these relationships as our concern remains that the energy used to produce the fuel is both renewable and additional. For example, bilateral and virtual PPAs could be equally valid given the right data in support of them. If a bilateral PPA experiences a situation where the there is no renewable source backing up the primary supply, then the assessment would be based on the energy used. If that is not renewable, then it will be assessed as such.

In relation to the claiming of support for both energy generation and the RFNBO production, we are content for this to continue to be appropriate. We see this energy support as central to decarbonising national grids and so do not want to block the use of this energy in the production of RFNBOs.

Where a renewable generation plant has its life extended to support RFNBO production, providing that it can be demonstrated that its grid load has been picked up by newer generation, then this could be seen as additional. These are likely not clear-cut situations but will be assessed on a case-by-case basis for whether they constitute additional energy. We encourage early engagement with the RTFO Administrator to understand evidence requirements.

Several respondents asked for waste to energy and bio-fuelled backup generators to be considered as viable energy sources for RFNBOs. We can confirm we are not revisiting this suggestion, which was covered in the 2016 consultation on RFNBOs. The core efficiency issues with the multiple process steps for this type of RFNBO production have not altered, so this will remain an un-qualified pathway.

We can also confirm that there is no scope within the RTFO for energy-based convertibility between different types of fuels and we have no plans to alter this approach.

On the complex issues of energy sourcing, we disagree that there it is not possible to identify excess energy. Any unused capacity represents a quantity of excess energy which is effectively turned down using various economic tools. Avoiding these scenarios provides an opportunity to produce RFNBOs.

In terms of the fractional production and feedstocks issues raised, the RTFO supports a consignment-based assessment. This means that the feedstocks, or energy sources, used allow the same production site to produce fuels that are assessed differently according to their inputs. As an example, a tonne of hydrogen produced with 30% qualifying energy and 70% non-qualifying energy would be issued with RTFCs based on the qualifying 30%. The RTFO also already provides differing incentives where specific production paths result in the same fuel even where the same feedstock is used. This enables the support of strategic and novel technologies.

Overall summary of responses.

An overarching theme of the responses was that any changes to the treatment of RFNBOs should maintain high emissions saving standards and continue to be seen as sustainable by wider industry and the public.

There were a range of responses asking for more detail on all policy proposals, while many also called for complexity in the administration to be minimised where possible. The guidance we have published alongside this document aims to deliver that clarity while also setting out possible evidential requirements.

There were several requests for changes to policies outside the scope of this consultation. This included policy charges for grid access and wider energy market reform. DfT will continue to work with other departments, including BEIS on topics such as these.

There were also several suggestions that eligibility of power related policies, such as the use of PPAs to evidence additionality and renewability should be extended beyond RFNBOs. Again, this was beyond the scope of this consultation, but we welcome further engagement from industry in the future.

Summary of the government response

We are satisfied that there are no fundamental issues with the underlying proposals in the consultation. We will therefore proceed with the proposed expansion of eligibility for the supply of RFNBOs under the RTFO. This includes:

- renewable energy supplied via a grid;

- clarification of the terms of additionality for renewable energy supply; and

- recognition of regionalised sub-grids for the purpose of grid GHG intensity calculations.

Alongside this document we have published detailed guidance on the production of RFNBOs under the RTFO. The RTFO Administrator will consider proposals under this guidance from its publication date. We will, subject to parliamentary process, introduce legislation in 2022 to further support the principles set out.

This set of measures will support RFNBO producers by enabling significantly more conditions under which installations can qualify for RTFCs. This will allow increased investment in the short term and in the longer term should lead to a reduction in cost of RFNBO production.

By stimulating increased RFNBO supply under the RTFO development fuel target, we will also see the overall cost of the RTFO reduced through lower buy-out of this part of supplier’s obligations.

3. The level of support for biohydrogen

Background

Most hydrogen production across the world uses fossil methane reformation, either using steam (SMR) or autothermal (ATR) processes. However, these processes can also use bio-methane to produce renewable hydrogen, which is eligible for support under the RTFO. To date, all renewable hydrogen under the RTFO has been considered a development fuel, irrespective of its production pathway. This means that hydrogen produced from biomethane in an existing gas reformation facility can qualify for development fuel certificates.

Concern has been raised that this level of reward creates a risk to the development of more advanced fuel production pathways. This is due to the relatively low cost of operation and the existing installed capacity of gas reformers. However, it is important to acknowledge that gas reformation is suitable for the addition of the advanced technology of carbon capture and storage (CCS). CCS has been identified as a strategic technology by the Committee for Climate Change, it also features in the Prime Ministers' 10-point plan for a Green Industrial Revolution (10MT of capture and storage annually by 2030)[9] and the UK Net Zero Strategy[10] . This combination of technologies to produce hydrogen from biological feedstocks could deliver low carbon, or potentially carbon negative hydrogen.

Summary of proposals

Our proposals in relation to biohydrogen had two parts:

- Remove development fuel support for the use of gas reformation to produce biohydrogen. This would see conventional gas reformation derived biohydrogen eligible for standard RTFCs under the main obligation target only. They would retain the same energy and feedstock multipliers already in use.

- Retain development fuel support where gas reformation also utilises substantial CCS to produce biohydrogen.

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[9] https://www.gov.uk/government/news/pm-outlines-his-ten-point-plan-for-a-green-industrial-revolution-for-250000-jobs

[10] https://www.gov.uk/government/news/uks-path-to-net-zero-set-out-in-landmark-strategy

All other processes of hydrogen production will remain within the development fuel target. Table 1 provides an overview of current and proposed certificate eligibility.

Method of production	Current eligibility	Proposed eligibility
Biomethane+SMR	Development	Regular
Biomethane+SMR+CCS	Development	Development
Biomethane+ATR	Development	Regular
Biomethane+ATR+CCS	Development	Development
Biomass gasification	Development	Development
Direct to hydrogen biological processes (e.g., fermentation)	Development	Development
RFNBO hydrogen	Development	Development

Table 1 Examples of current and proposed future levels of reward for renewable hydrogen supply under the RTFO

Questions and government response

Q19. Do you agree or disagree that biohydrogen produced from biomethane reformation should be eligible for standard RTFCs rather than development fuel RTFCs?

Summary of responses

Total	Agree	Disagree
64	36	28

Just over half of respondents agreed with our proposals with a constructive set of responses both for and against the proposal.

Four respondents asked for confirmation of the number of certificates that would be awarded under a changed status for biohydrogen. One stated that if the cost to produce biohydrogen through SMR without CCS was comparable to other, main target, fuels, changing the support level was acceptable. Another respondent insisted that there was a need to ensure no double reward via mechanisms like the renewable heat incentive (RHI).

Two respondents who were opposed to the general inclusion of hydrogen produced from biomethane raised concerns that mass balancing across gas grids for hydrogen production risked extra losses of methane. They were also concerned that SMR production could drown out other development fuels because of the perceived low investment needed. Three respondents agreed that biomethane SMR/ATR without CCS loses the GHG savings that would be delivered from direct use of the biomethane as a transport fuel. One respondent felt the proposed change would encourage more RFNBO hydrogen production and so reduce pressure on land use.

One respondent felt that there should be a defined mechanism for development fuels to move into the main RTFO target when they achieve an appropriate level of technological and economic development. It was argued this would provide greater industry clarity.

Six respondents stated that as renewable hydrogen is a development fuel irrespective of production method then this should not change. Five argued that development fuels should be a category that can only be added to not subtracted from. They suggested it should be based on Annex IX of the EU renewable energy directive 2018/2001[11] (RED II). One respondent pointed out that in the 2017 consultation DfT recognised the value of biohydrogen.

Four respondents argued that certain ways of producing biomethane can be considered carbon negative without CCS (our understanding is that this is referencing the default values for manure in RED II) so should be allowed development fuel status if converted into biohydrogen. Three argued that carbon intensity should be linked to the number of certificates issued rather than changing the class of certificates.

Nine respondents, including a renewable energy association, argued that as there were no existing SMR facilities with on-site anaerobic digestion (AD) it is not a mature technology and so hydrogen from SMR of biomethane should remain a development fuel. Similarly, five proposed that as small scale SMR facilities have not been widely deployed this should be considered a new technology and be issued development fuel certificates. In contrast three respondents, including consultancies and a fuel producer, stated that as CCS is unproven technology and not ready to deploy at scale in 2022 it should not be a criterion for biohydrogen reward. Two respondents argued that no other fuel in the RTFO requires extra carbon mitigation (via CCS) so this should not be the case for biohydrogen. One argued that other biofuels like BioLPG should be considered development fuels if CCS is used.

Two respondents stated that SMR facilities were more likely to focus on blue hydrogen not renewable hydrogen and so the proposal was irrelevant. One respondent argued that the RTFO is dominated by biodiesel so retaining biohydrogen of all kinds as a development fuel is a very low risk.

Nine respondents including hydrogen producers, industrial associations and consultants asked that all hydrogen should get the maximum encouragement to increase its usage. Linked to the above, three fuel producers and hydrogen associations, argued that as hydrogen uptake is at an early stage it should either be treated differently or be supported by a different mechanism. Two respondents argued that price certainty is needed to drive investment so no change should be made. A fuel producer stated that the use of RTFCs alone have been insufficient to drive hydrogen investment and that as biohydrogen is a steppingstone to net zero, the development fuel status was justified.

Finally, one respondent asked that we increase targets to support hydrogen being eligible for standard RTFCs but cautioned that hydrogen does not fit a volume-based model designed around liquid fuels.

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[11] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC

Government response

We can confirm we intend to bring forward changes to the RTFO through legislation to re-classify hydrogen produced from biomethane via SMR/ATR without the use of significant CCS as a main obligation fuel.

In relation to requests for clarity around the number of certificates that would be issued as a non-development fuel we can confirm the current multipliers would continue to apply irrespective of the class of certificate issued. This means that 9.16 regular certificates would be issued for biowaste converted to biomethane and then biohydrogen.

The concern over double rewards for fuels is dealt with in the RTFO through the multiple incentive's clause (article 16 (2)(a)(ii) & 16 (3)(ea)), which prohibits the fuel or chemical precursor from having had support from any other support scheme in the European Economic Area (EEA). We can confirm fuels cannot not claim both RHI and RTFO support under this requirement. Associated with this, concerns regarding mass balancing biomethane across a grid and the ensuing losses, are mitigated as losses are accounted for within the RTFO assessment process and so does not constitute a new risk.

There were a range of reasons given by those that disagreed with the proposal. The most common concerned regulatory certainty and price stability. Annex IX of RED II was regularly quoted as a desirable example of an addition only regulation for comparison. We understand the attraction of this from a business perspective however this seems unsuitable in the context of the RTFO. Unforeseen sustainability issues could arise that need to be addressed as and when they become evident to maintain the integrity of the RTFO. Whilst the consultation response in 2017 did positively comment on biohydrogen, which remains true in most cases, we now have a better understanding of the short-term attraction of SMR/ATR biohydrogen. It is clear that without CCS, use of biomethane for hydrogen production would have a worse result in terms of carbon savings than the use of biomethane directly as a transport fuel.

The argument that biomethane can have a negative carbon intensity without CCS is only applicable in certain counterfactual cases. Importantly, once converted into biohydrogen the fuel would still have a higher GHG impact than direct use of biomethane. It is also important to state that the RTFO is constructed as a volume-based reward scheme with corrections for energy density. Adding a GHG factor to this is a change which is beyond the scope of this consultation. The RTFO was previously complemented by a Greenhouse Gas reduction scheme, which ended in 2020. A forthcoming post implementation review of the GHG scheme will seek feedback on these now discontinued provisions.

The opinions concerning the lack of existing deployment of gas reformation with CCS or co-located AD does not present a case for continuing to include all biohydrogen in the development fuel category. This is because the development fuel target is intended to encourage under deployed technology as much as specific fuel types and all the components proposed are well established technologies. Splitting processes based on scale or being co-located would also be challenging to administer within the RTFO. Similarly, the counter argument that CCS is not currently deployed and so should not be introduced as a criterion is not determined as relevant as the development fuel obligation is meant to incentivise this type of progress. We should also highlight that the application of a process like CCS is not in itself sufficient to establish a fuel as a development fuel. The key here is that both the fuel and the process represent a strategic development goal.

We acknowledge that the majority of SMR capacity is likely to focus on developing fossil hydrogen with CCS rather than renewable hydrogen. However, we are aware of projects that are investigating using biomethane in existing SMR plants. Because of this, it remains important that we ensure the RTFO provides an appropriate level of reward for this fuel production pathway. Given the carbon savings from SMR/ATR biohydrogen are likely lower than that where biomethane is used directly, we do not think the former should be eligible for a higher level of reward. The policy change is aimed to encourage fuels to be deployed where carbon savings are maximised.

In terms of more wide-ranging support for the development of the hydrogen industry, this cuts across several ongoing government workstreams including the Hydrogen Business Model[12] and the Net Zero Hydrogen Fund[13] that are being led by BEIS as part of the 2021 UK Hydrogen Strategy[14]. While we remain linked with policy development in those areas, it remains important that the RTFO continues to focus on its policy aims. This is primarily to deliver carbon savings through the use of low carbon fuels in transport.

In relation to the point raised around hydrogen not fitting into a volume-based model designed around liquid fuels, we can confirm that all gaseous fuels are rewarded on a kg to litre equivalent basis within the RTFO. This means certificates are issued relevant to their energy density when compared to the average liquid fuel.

Q20. Certain advanced production methods for biohydrogen are likely to be of strategic future importance and require new investments, such as addition of CCS. Do you agree or disagree that when these methods are used, biohydrogen produced from biomethane reformation should remain eligible for development fuel RTFCs?

Summary of response

Total	Agree	Disagree
63	51	12

Retaining the status of biohydrogen produced from gas reformation with CCS was generally supported in the responses received. Across the responses there were some detailed and useful qualifications and insights provided.

Seven respondents were in favour because of the potential of biohydrogen to achieve negative emissions, something critical to hitting net zero targets. Five respondents expressed concern that DfT should avoid policy conflicts around CCS, particularly avoiding double subsidies or over support for the technology. Responses from a renewable energy, transport association and others suggested that the RTFO should support CCS specifically, with RTFCs issued to CCS facilities. They suggested this should not need to be directly linked to fuel production.

Three more respondents suggested that where CCS is fitted to either the AD unit or SMR facility, fuel produced should qualify for development fuel status. Three further

12 https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen
13 https://www.gov.uk/government/consultations/designing-the-net-zero-hydrogen-fund
14 https://www.gov.uk/government/publications/uk-hydrogen-strategy

respondents felt that the extra development certificate revenue would be essential to support new CCS technology. One industry group advocated that support be restricted to situations where the captured carbon be transferred to full storage, and we disallow carbon usage. A counterpoint was offered by a green hydrogen supplier and a fuel supplier who suggested that CCS clusters will be irrelevant to fuel production because BEIS will provide sufficient support for the technology via separate schemes. An oil company suggested that if CCS was used, fossil fuels should be considered eligible for RTFO support.

An oil producer suggested all “advanced technologies” should receive specific support, while two other energy and fuel companies felt that, with CCS, biomethanol should receive development fuel support; another respondent made a similar argument about ethanol production. As with question 19, an energy consultant felt that small scale SMR systems were an emerging technology and should remain eligible for development fuel certificates. Conversely, an energy company argued that none of the proposed technologies are new, including CCS, and so should not qualify for dRTFCs. A consultant and a gas supplier suggested that government should regularly review the reward for all methodologies and reduce the reward where it had become mainstream. A transport association queried the definition of “strategically important” as a defining attribute for development fuels. As in question 19 an oil refiner argued that development fuels should be an additive list, modelled on Annex IX of RED II. They argue that once a fuel is assigned development fuel status, it should not be removed.

An electrolysis company wanted confirmation that CCS was not supported for fossil hydrogen production with these changes. One respondent asked for the GHG intensity to be used to alter the value or number of certificates earned. Another respondent requested that life cycle assessments used the whole scope of production through to use, capturing losses along the way.

A gas producer asked that mass balance was permitted to move biomethane from AD plants to SMR plants for qualifying fuel production. Three energy suppliers and a port operator rejected the use of SMR and SMR+CCS entirely and suggested only electrolysis be supported under the RTFO. In common with question 19, two respondents argued that SMR+CCS was so focussed on blue hydrogen that it was irrelevant to renewable hydrogen. An environmental NGO suggested that as there is no operational example of SMR+CCS of biomethane, it should not be eligible for support under the RTFO.

A gas producer was concerned that allowing any kind of biomethane conversion to be supported would draw the fuel away from direct uses. A different gas supplier argued that biomethane is not a valid development fuel feed stock meaning biohydrogen from SMR/ATR should not have originally been classified as development fuel.

One respondent felt there should be no support under the RTFO for any fuel that does not pay fuel duty.

Government response

We can confirm that biohydrogen produced by SMR/ATR will continue to be eligible for development fuel certificates only where substantial CCS is used. We consider substantial CCS to mean that 50% or more of the CO_2 resulting from the production of biohydrogen must be captured and stored. We can also confirm that other biohydrogen production pathways including gasification and direct processes like fermentation will continue to be eligible for development fuel certificates as shown in Table 1 on page 31.

We agree that the potential to initiate production of negative emissions from transport is a benefit of the policy. We will continue to work closely with other government departments to ensure that we create a consistent framework of government policy on CCS. We are however unable to provide direct RTFC support for CCS where it is unrelated to fuel supply. The primary powers underpinning the principles of the RTFO are clear that it can only support transport fuels.

The guidance published alongside this document sets out how the 50% threshold for CCS will be assessed. We expect the CCS capacity to be associated to a biohydrogen production system, however, are not proposing to specify exactly where that capacity must be installed in the production chain. The key point here is to bring the carbon savings in line with direct use of biomethane. The economics of CCS are still uncertain, but we are encouraged that some respondents felt the extra revenue from dRTFCs would be beneficial to stimulate CCS investments.

We agree that it would be preferable to ensure that any captured carbon be stored long term; further detailed guidance in this area has not yet been developed. We will continue to work with BEIS to provide greater clarity on storage requirements and verification in due course.

While we expect that the BEIS incentives for CCS through the CCS cluster plans[15] will be sufficient to drive development of individual schemes, this does not mean we should not also recognise the role of CCS in delivering low carbon intensity renewable fuels. The purpose for our proposal is to place the correct level of incentive on transport fuels and drive the best usage. Including biohydrogen with CCS in the development fuel category supports this aim.

The suggestion that use of CCS would make fossil fuels eligible for RTFO support is incorrect. The "renewable" requirement within the RTFO ensures such fuels cannot be supported. While we are currently exploring adding certain specific non-renewable fuels to the RTFO, namely recycled carbon fuels (RCFs), there are no plans to open the scheme to wider non-renewable fuels.

The suggestion that the technology alone or the specific use of CCS be a criterion for development fuel status does not reflect the purpose of the development fuel category. The development fuels obligation was initiated to simultaneously provide extra support to both fuel types and processes that are considered strategically important. Being only one or the other is not sufficient for qualification. Linked to this, because of the RTFO legislative structure, there is no systematic method to move fuels out of the development obligation and no such a mechanism was considered in this consultation. The request for the development fuels list to be only additive was also raised and responded to in the summary of question 19.

In extension to the above response, we can confirm that we are only viewing CCS as a mitigation for renewable fuels, not as a route to support more conventional "blue hydrogen"

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[15] https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-2

production from fossil methane. The request to change the RTFO certificate quantity or value because of GHG values, as summarised in the answer to question 19, is also not considered practical.

Currently mass balancing is allowed for transmission of gasses across a network or fuel within a production/blending environment. There is no intention to change the principles around this. The life cycle assessments (LCA) of fuels carried out by the RTFO Administrator already consider the whole lifecycle, inclusive of transmission losses. As such, this would also be accounted for in the CCS element of an LCA where there was transmission between capture and storage.

Requests that we consider any deployment of CCS with renewable fuel production as a development fuel, would be counter to the wider purpose of the development fuel obligation. Fuels included in the development fuel obligation should both meet the relevant sustainability criteria and be considered of strategic importance towards transport decarbonisation objectives.

The lack of deployed examples of CCS is not a reason to reject its inclusion in the development fuel category. This obligation was implemented to incentivise investment types of fuel production not already at commercial scale. We are aware of proposals to use contractual arrangements to deliver biomethane to existing SMR plants to produce biohydrogen. As a result, it is relevant for these fuels and pathways to be considered under the RTFO even where current production levels are negligible.

Regarding biomethane not being an eligible development feedstock, we do not agree with this interpretation. For the purpose of the RTFO, the feedstock is considered to be the primary energy source, which in this case would be the bio-waste or residue from which the biomethane is derived. Wastes and residues are valid development fuel feedstocks.

We do not agree that RTFO support should be limited to fuels which are subject to fuel duty. The RTFO is designed to incentivise renewable transport fuels, whereas matters of taxation are considered by the Treasury.

We are glad to see such widespread support for the application of CCS to gas reformation in biohydrogen production. We intend to pursue the biohydrogen amendment and to present it with sufficient clear guidance to allow stakeholders to make the most of the opportunities this presents. This guidance will be published in draft at the same time as the statutory instrument to implement the biohydrogen changes and then in final form in time for the RTFO year 2023.

4. Next steps and geographical coverage

RFNBOs additionality principle

The change in approach relating to additionality and regional grids can be taken forward within the current drafting of Renewable Transport Fuel Obligations Order 2007. This means the Administrator will consider applications against these updated criteria from the publication of this document. The Administrator has published detailed guidance alongside this government document to aid applications for dRTFCs in respect of RFNBOs.

To further support the principles of additionality, we will also introduce an amendment to the Renewable Transport Fuel Obligations Order 2007 to include a definition of additionality. Subject to parliamentary approval this will come into force during 2022.

Biohydrogen

The above-mentioned amendment to the Renewable Transport Fuel Obligations Order 2007 will also include the required provisions to reclassify biohydrogen not produced with CCS. Subject to parliamentary approval, these provisions will come into force from 1 January 2023, to align with the RTFO annual cycle. Draft guidance for the biohydrogen changes will be published alongside the statutory instrument required to make these changes.

All amendments to the Renewable Transport Fuel Obligations Order 2007 will apply across the whole of the United Kingdom.

Annex: 1 List of consultation policy questions

Hydrogen and renewable fuels of non-biological origin

11. Is "renewable energy that would not have been available to the grid in the absence of power demand from the RFNBO plant in question" an appropriate definition of additional renewable energy?

12. Should the Administrator be able to take into account the use of power purchase agreements (PPAs) as evidence that suppliers have purchased additional renewable energy in order to allow the renewable power generation to be located in a separate location from the RFNBO production facility?

13. A consequence of allowing the use of PPAs to demonstrate renewability, in combination with also permitting other suppliers to use a grid average renewability, is that the same renewable energy could be accounted for more than once. We consider this to be low risk when hydrogen energy and other RFNBO demand is small compared to the total renewable energy available on the grid. We are seeking views on whether this risk is acceptable. Is this risk acceptable?

14. Should appropriate adjustments be made to the amount of renewable energy supplied to a RFNBO production facility to account for transmission losses where renewable energy is transferred over the electricity grid?

15. Do you have any comments on the proposal to use a 30-minute time period for temporal correlation of renewable energy production and use, in cases where renewable energy has been purchased and transmitted across the grid?

16. Should the Administrator be able to permit fuel suppliers to use local grid GHG emissions factors in RFNBO GHG emission calculations? Circumstances in which this might be appropriate include where there are local grid constraints or other local conditions which mean that the local grid GHG intensity differs substantially from that of the national grid.

17. A consequence of allowing local grid GHG emissions to be used in calculating the GHG intensity for a RFNBO is that GHG savings may be claimed by a production facility on a low GHG emission regional/local grid which have also been accounted for in the average national grid GHG intensity. Is this risk acceptable?

18. Have we captured all the additionality scenarios as set out in the proposals in the chapter and in the decision tree (Figure 13)? Please suggest alternatives with evidence

19. Do you agree or disagree that biohydrogen produced from biomethane reformation should be eligible for standard RTFCs rather than development fuel RTFCs?

20. Certain advanced production methods for biohydrogen are likely to be of strategic future importance and require new investments, such as addition of CCS. Do you agree or disagree that when these methods are used, biohydrogen produced from biomethane reformation should remain eligible for development fuel RTFCs?