Technical assistance to assess the potential of renewable liquid and gaseous transport fuels of non-biological origin (RFNBOs) and recycled carbon fuels (RCFs) to establish a methodology to determine the share of renewable energy from RFNBOs and to develop a framework on additionality in the transport sector

Final report | Task 2

Methodology to determine the share of renewable energy

EUROPEAN COMMISSION

Directorate-General for Energy
Directorate C— Green Transition and Energy System Integration
Unit C2—Decarbonisation and Sustainability of Energy Sources

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Draft final report | Task 2
Methodology to determine the share of renewable energy

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Table of Contents

1. Summary **1**

2. Introduction **5**

2.1 Project and report structure 5

2.2 Policy context 5

2.2.1 Case 1 6

2.2.2 Case 2 7

2.2.3 Case 3 7

2.3 Methodology 8

3. Aspects concerning all cases **9**

3.1 Energy consumption system boundaries 9

3.1.1 Electricity consumption 10

3.1.2 Heat consumption 10

3.1.3 CO_2 capture and conditioning 12

3.2 Combination of cases 13

3.3 Target additionality 16

3.3.1 Ex post approaches 17

3.3.2 Ex ante approach 18

3.4 RFNBO consumption in sectors other than transport 19

3.4.1 Green hydrogen in refineries 19

3.4.2 Renewability requirements across sectors 21

4. Case 1 – Average grid electricity **23**

4.1 Case description and requirements in RED II 23

4.1.1 Average electricity 23

4.1.2 Minimum GHG emission savings 23

4.1.3 System perspective on Case 1 25

4.2 Options to meet the requirements in RED II 26

4.2.1 Determining the average share of RES-E 27

4.2.2 Considering imports of electricity 28

4.2.3 RFNBO imports from non-EU countries 28

5. Case 2 – Direct connection **32**

5.1 Case description and requirements in RED II 32

5.1.1 Timing of RES installation commissioning 32

5.1.2 Supply exclusively via direct connection 32

5.1.3 Definitions 33

5.2 Options to meet the requirements in RED II 34

5.2.1 Timing of RES installation commissioning 34

5.2.2 Supply exclusively via direct connection 37

6. Case 3 – Renewable grid electricity **40**

6.1 Case description and requirements in RED II 40

6.1.1 Renewable electricity sourcing 40

6.1.2 Additionality 41

6.1.3 Temporal correlation ... 42
6.1.4 Geographical correlation ... 42
6.1.5 No double counting ... 43
6.2 Why do additionality, temporal and geographical correlation matter? ... 43
6.3 Fulfilment vehicles ... 48
6.3.1 Guarantees of origin ... 48
6.3.2 Power purchase agreements ... 50
6.3.3 Private or public RES-E deployment funds ... 52
6.3.4 Project-level assessments ... 53
6.4 Options to meet the requirements in RED II ... 54
6.4.1 Additionality | Deployment additionality ... 54
6.4.2 Additionality | Surplus electricity ... 60
6.4.3 Temporal correlation ... 63
6.4.4 Geographical correlation ... 71
6.4.5 No double counting ... 76
6.4.6 Eligible sourcing models for renewable grid electricity ... 77
7. Increasing requirements over time ... 79
7.1 General considerations ... 79
7.2 Potential concept for Case 2 ... 82
7.3 Potential concept for Case 3 ... 83
8. Case studies ... 86
8.1 Case study 1: Kerosene production with grid electricity in Norway (Case 1) ... 86
8.1.1 Introduction ... 86
8.1.2 Requirements and evidence provision during RFNBO production ... 87
8.1.3 Summary and learnings from this case study ... 88
8.2 Case study 2: Hydrogen production with grid electricity in Austria (Case 1) ... 89
8.2.1 Introduction ... 89
8.2.2 Requirements and evidence provision during RFNBO production ... 89
8.2.3 Summary and learnings from this case study ... 90
8.3 Case study 3: Hydrogen production with colocated solar PV in Spain (Case 2) ... 90
8.3.1 Introduction ... 90
8.3.2 Requirements and evidence provision before the start of RFNBO production ... 92
8.3.3 Requirements and evidence provision during RFNBO production ... 94
8.3.4 Summary and learnings from this case study ... 95
8.4 Case study 4: Kerosene production with colocated PV and wind in Saudi Arabia (Case 2) 96
8.4.1 Introduction ... 96
8.4.2 Requirements and evidence provision before the start of RFNBO production ... 97
8.4.3 Requirements and evidence provision during RFNBO production ... 98
8.4.4 Summary and learnings from this case study ... 98
8.5 Case study 5: Kerosene production with RES-E GOs in Poland (Case 3) ... 98
8.5.1 Introduction ... 98
8.5.2 Requirements and evidence provision before the start of RFNBO production ... 99
8.5.3 Requirements and evidence provision during RFNBO production ... 99
8.5.4 Summary and learnings from this case study ... 105
8.6 Case study 6: Hydrogen production with a contracted offshore wind farm in the Netherlands (Case 3) ... 105

8.6.1 Introduction ... 105
8.6.2 Requirements and evidence provision before the start of RFNBO production ... 111
8.6.3 Requirements and evidence provision during RFNBO production ... 112
8.6.4 Summary and learnings from this case study ... 114

9. Sources ... 116

10. Annex: Long list of options to fulfil each RED II requirement ... 119

10.1 Evaluation criteria ... 119
10.1.1 Effectiveness for RED II compliance ... 119
10.1.2 Applicability across Member States ... 120
10.1.3 Applicability in non-EEA countries ... 120
10.1.4 Economic burden for operators ... 121
10.1.5 Administrative burden ... 122
10.2 Case 2 – Direct connection ... 122
10.2.1 Timing of RES installation commissioning ... 122
10.2.2 Supply exclusively via direct connection ... 124
10.3 Case 3 – Renewable grid electricity ... 127
10.3.1 Renewable electricity sourcing ... 127
10.3.2 Additionality ... 128
10.3.3 Temporal correlation ... 141
10.3.4 Geographical correlation ... 146

List of Tables

Table 1. Potential combination of RFNBO production cases ... 14
Table 2. Hydrogen CO_2 content for different temporal correlation modes ... 47
Table 2. Example calculation for PLA proving positive net contribution of a PPA with an RFNBO operator ... 59
Table 3. Intermittent RES-E share in total generation of EU-27 Member States ... 70
Table 4. Options for RFNBO producers to demonstrate compliance with renewability criteria depending on RES-E sourcing model ... 77
Table 5. Main parameters of case study 1 ... 86
Table 6. Main parameters of case study 2 ... 89
Table 7. Main parameters of case study 3 ... 91
Table 8. Main parameters of case study 4 ... 97
Table 9. Main parameters of case study 6 ... 99
Table 10. Technical parameters of the hypothetical kerosene production plant in Poland. ... 102
Table 11. Main parameters of case study 6 ... 106
Table 12. RES-E sourcing options to meet the total yearly demand ... 106
Table 13. Hydrogen production cost estimation for different options (EUR/MWh H2) ... 107
Table 14. Estimated need for peak hydrogen storage ... 109
Table 15. Hydrogen storage requirements in the PPA option ... 110
Table 16. Responsibility for the risk from forecasting errors and considerations ... 113
Table 17. Preliminary evaluation of options to fulfil the requirement as regards the timing of RES installation commissioning ... 123
Table 18: Preliminary evaluation of options to fulfil the requirement as regards the supply exclusively via direct connection ... 125
Table 19. Preliminary evaluation of options to fulfil the requirement of deployment additionality ... 129
Table 20. Preliminary evaluation of options to fulfil the requirement of surplus electricity ... 132
Table 21. Preliminary evaluation of options to fulfil the requirement of target additionality ... 138
Table 22. Definition of options for temporal correlation ... 141

Table 23: Preliminary evaluation of options to fulfil the requirement of temporal correlation 142
Table 24. Preliminary evaluation of options to fulfil the requirement of geographical correlation 146

List of Figures

Figure 1. Three cases defined by RED II in which RFNBOs can account for the transport sector's RES target 7
Figure 2. Overview of the components of a typical water electrolysis production facility 9
Figure 3. Simplified schematic for synthetic crude oil production 10
Figure 4. Illustrative example of an electrolyser combining Cases 2, 3, and non-renewable fuel production. 15
Figure 5. Options to include RFNBOs used as intermediate products to produce conventional fuels (in this example, hydrogen in refineries) in RES-T share calculation 21
Figure 6. Grid emission factors for selected European countries. 24
Figure 7. Share of renewable energy in electricity as reported in SHARES for selected countries reporting values in the tool (considering EU Member States, UK, NO, IS). 27
Figure 8. RES-E share as reported by different sources for Mexico, Morocco, the UK, and Uruguay. 30
Figure 9. RFNBO GHG footprint using average grid emission factors 44
Figure 10. Sourcing model for unbundled GO certificates 49
Figure 11. Sourcing model for green power products (bundled GO certificates) 49
Figure 12. Sourcing model for physical PPAs 51
Figure 13. Sourcing model for financial PPAs 52
Figure 14. Illustration of the general principle of private or public RES-E deployment funds 53
Figure 15. Analysis of RES-E forecast accuracy 68
Figure 16. Illustrative example of RES-E sourcing under deployment additionality 85
Figure 17: Full load hours of an electrolyser depending on capacity relative to connected PV park. .. 95
Figure 18: RES-E share and electricity price analysis Poland 2020 102
Figure 19. Diurnal profiles of four offshore wind farms in the Dutch North Sea 108
Figure 20. Monthly profiles of four offshore wind farms in the Dutch North Sea 109
Figure 21. Hydrogen in and out storage flows as a share of a total monthly demand 110
Figure 22: Options to foster target additionality 135
Figure 23: Bidding zone configuration in Europe 148
Figure 24. European zonal model used by ENTSO-E 149

Disclaimer

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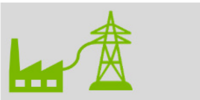
1. Summary

The recast Renewable Energy Directive (RED II) (DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL, 2018) created a legal basis for using renewable liquid and gaseous transport fuels of non-biological origin (RFNBO) for renewable energy target achievement in the European Union (EU). Since then, the public and private sector allocated significant resources to scale-up RFNBO technologies, which are seen as indispensable pillar of decarbonised energy systems.

The risk of a fast RFNBO scale-up lies in their production, which requires large amounts of electricity that may cause significant CO_2 emissions should this electricity be fossil-based. Requirements are needed to ensure future RFNBOs are based on renewable electricity (RES-E). RED II introduces requirements by which evidence can be produced that a unit of RFNBO constitutes a renewable energy carrier (Article 27 and Recital 90) to count towards transport sector renewable energy targets (RES-T). This will be specified in a Delegated Act (DA) in 2021. Section 2.2 details the policy context.

This report recommends options for RFNBO producers to demonstrate compliance with RED II requirements. It considers literature and position papers (see Section 9) and discussions with the Commission and other experts. This report discusses the requirements, their fulfilment options, and their strengths and weaknesses through three cases of RFNBO production anticipated by RED II Article 27.

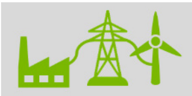


Case 1 – Average grid electricity (Section 4) occurs when the electricity for RFNBO production is sourced from the electricity grid without further technical or regulatory measures. This represents a default case that imposes minimal obligations on RFNBO producers. RED II foresees no requirements beyond minimum greenhouse gas (GHG) savings in this case. Details to implement this case's provisions include:

- The RED II requirement that **70% GHG savings** be achieved through RFNBOs means that Case 1 is only applicable in a few countries with a high share of nuclear or renewable power generation and therefore low electricity system GHG emissions.
- The Short Assessment of Renewable Energy Sources (SHARES) tool provides **adequate data** to implement Case 1 in EU Member States and some other European countries. For non-EU countries, international and national dataset analysis for four exemplary countries shows that producers in these countries should be required to apply the same accounting methodology as under SHARES to warrant consistent reporting.
- Case 1 has some drawbacks related to the total emissions, double counting of renewable energy content, and a level playing field in terms of market development (see Section 4.1.3). These drawbacks could be tolerated as Case 1 can only be applied widely once electricity systems approach GHG neutrality. Alternatively, Case 1 could potentially be supplemented with more requirements, such as additionality. However, this would require legal changes and would reduce the simplicity of this case.

Case 2 – Direct connection (Section 5) anticipates a model where an RFNBO producer sources electricity via a direct connection from an RES-E installation. Operators must strongly couple the commission and operation of an RFNBO plant and an RES-E asset, but they can claim 100% renewability for consumption sourced via a direct connection. RED II requires that the RES installation comes into operation at the same time or after the RFNBO facility. It also requires evidence that no electricity is sourced via the public grid for the part of the consumption that is claimed to fulfil Case 2. The project team's recommendations on options to fulfil these requirements are as follows:

- Regarding the **timing requirement**, the operation's start should be verified by confirming the commissioning dates of both assets. The project team further recommends a time interval of 3 months within which both assets have to be commissioned to be considered as starting operation at the same time.
- Verifying that neither the RFNBO facility nor the RES-E asset is connected to the grid is effective at establishing that the asset is **exclusively supplied** through the direct connection.
- If there is a **grid connection**, RFNBO producers can claim 100% RES-E for that amount of electricity where consumption and generation match. Matching should be verified by smart metering at a granularity of 15 minutes.



Case 3 – Renewable grid electricity (Section 6) foresees RFNBO production that sources electricity from the grid, which is claimed to be fully renewable. This case also allows for 100% renewable RFNBOs but does not require RFNBO production to be coupled to a specific RES-E asset as strictly as in Case 2. However, RED II requires operators to aid the expansion and integration of RES-E in Case 3. For example, operators need to finance or deploy additional RES-E capacities and prove temporal and geographical correlation between RFNBO and RES-E production. The project team recommends that RFNBO operators include the following evidence:

- Sourcing from new, unsubsidised RES-E assets should be the primary option for **deployment additionality**. Under this first fulfilment option, the project team recommends allowing sourcing both with direct contractual relationship—via a power purchase agreement (PPA), possibly complemented by using guarantees of origin (GOs)—and without direct contractual relationship (via a subset of eligible GOs). Sourcing from old, previously subsidised assets should also be allowed, but only under specific circumstances, meaning that through project-level assessment, proving a PPA with RFNBO producers makes a difference between the asset's closure and continued operation.
- The DA should not directly address the use of **surplus RES-E**, as no solid mechanism to address this has been found.
- GOs are not an appropriate vehicle to verify **temporal correlation** as of today (2021) because they only earmark the month of RES-E production, which is not sufficiently granular. Hourly GOs could be used in the future, should they become available. The DA should therefore mainly rely on ensuring temporal correlation either between RFNBO production and RES-E production with a directly contracted asset (such as a PPA) based on a comparison with the RES-E share in the grid or a combination. The latter may be implemented through matching RFNBO production planning with the day-ahead RES-E infeed forecast. RFNBO producers may install or contract electricity storage capacity to temporally decouple their production from RES-E generation.
- Bidding zones should be the default rule of **geographical correlation** as they provide a clear definition and consider grid bottlenecks to some extent. Member States should be allowed to limit the areas for RFNBO production further by designating suitable areas. National authorities or transmission system operators

(TSOs) should also be allowed to permit cross-zonal RFNBO and RES-E production, if bidding zones are sufficiently interconnected. In countries where the electricity market is not developed enough to use the aforementioned options, the country territory may need to be used as a fallback identification for geographical correlation.

- **No double counting** is another RED II provision for Case 3. Double counting renewable energy properties at the Member State level is prevented by the reporting duties already in place under RED II. To prevent double counting at the producer level, RFNBO producers must be obliged to cancel any GOs that they use to claim the renewability of their consumed electricity (in case they do use GOs).

Introducing the Case 2 and Case 3 requirements in a **gradual, two-phase approach** is a suitable compromise between RFNBO market scale-up and sustainability (see Section 7). The transition between the two phases should be defined by a year (e.g., 2024) to ensure market predictability. Rules in both phases should be applied in a way that does not create stranded assets by requiring retroactive compliance where this is difficult or impossible (i.e., plant-related requirements, such as asset location). Requirement phasing could be designed as follows:

- **Case 2 – Direct connection:** The project team recommends that the relative timing of the commissioning dates of RFNBO and RES-E installation should be introduced in a gradual two-phase approach. The time period within which the commissioning dates would be considered *at the same time* should then amount to 12 months in the first phase and be reduced to 3 months in the second phase. However, the DA may not have the power to introduce such a phased approach. In that case, 3 months should apply from the beginning.
- **Case 3 – Renewable grid electricity:** According to the Commission, the legal feasibility of a two-phase approach is less problematic than in Case 2, but it is also questionable. If the concept can be included in the DA, the granularity of temporal correlation should be less demanding in the first phase and correlation should be evaluated based on a full day's consumption instead of each individual hour. This would ease the operation of the first industrial-scale RFNBO production facilities in the coming years. Additionality could be required only for a given percentage of electricity consumption in the first phase to allow liquid markets to develop for RES-E from new and unsubsidised assets before all consumption has to be covered by additional RES-E capacities.

There are significant **items to be considered across the cases:**

- **For energy system consumption boundaries,** all electricity consumption related to the main hydrogen production unit, auxiliary systems, further synthetisation units, and CO_2 delivery units should be considered. The end of the system boundary should be determined as the point of RFNBO exit from the main production units and auxiliary systems. In practical terms, this point of RFNBO exit could be an external compression system, a pipeline or other transport medium, onsite storage, etc. The project team recommends that the Commission investigate how to best treat heat inputs in RFNBO production that are currently not considered for renewable energy content under RED II. Finally, the Commission should consider that the energy inputs for CO_2 capture and conditioning could be taken into account in a way that incentivises the use of renewable carbon inputs for RFNBO production (see Section 3.1).

- RFNBO producers can **combine the three cases** and non-renewable fuel production during the operation of a single plant to achieve more flexibility and asset utilisation (see Section 3.2).
- If RFNBOs are counted as fully renewable in Cases 2 and 3, RES targets should fully reflect the additional RES-E demand for RFNBO production. The next revision of RED should address such **target additionality**. This revision could account for RFNBOs under the Article 3 RES target based on the calorific value of RFNBOs rather than counting the RES-E input for RFNBO production for target achievement. This change would mean that additionality is not required for the entire electricity consumption of the RFNBO production, but only for the conversion losses during production. Thus, the poor energy efficiency of RFNBO production would be compensated by additionality requirements (see Section 3.3).
- **Union-wide, cross-sectoral renewability criteria** for RFNBOs should be introduced to ensure transparent, liquid markets and sustainable RFNBO ramp-up. The DA pursuant to RED II Article 27.3 should be a basis for this. If hydrogen or its derivatives were used in sectors other than transport, the Act's provisions should also be applied to determine the renewable energy content of these fuels. Should hydrogen or its derivatives be counted towards the Article 3 target in the future, the criteria could also be applied (see Section 3.4).

A set of six fictitious **case studies** illustrates how the described methodologies could be executed in practice (see Section 8). Some of the indicative learnings from these case studies are as follows:

- Demonstrating compliance with the requirements does not create a disproportionate administrative burden.
- Allowing RES-E sourcing from eligible assets via GOs in addition to PPAs can significantly reduce risk for the RFNBO business case—although sourcing exclusively through the GO spot market may also be too volatile.
- Increasing requirements over time (see Section 7) might help alleviate many of the initial pains in this nascent market.
- Compliance costs are significant, but they are not disproportionate in relation to the cost gap between RFNBOs and conventional fuels that exist in any case. The climate benefit of compliance must also be taken into account.

2. Introduction

2.1 Project and report structure

This project is structured into three tasks, each of which is covered by a separate report. This report focuses on Task 2, which is concerned with developing detailed rules that producers of renewable liquid and gaseous transport fuels of non-biological origin (RFNBOs) can follow to provide evidence that they use fully renewable electricity in the production of their fuel to set the methodology under Article 27.3, subparagraph 7 of the Renewable Energy Directive (RED II).

This report presents the findings in this task from project inception in May 2020 to March 2021, with some last updates in November 2021. Some sections presented in the first interim report are not fully included in this report for ease of reading; instead, they are included in the Annex. Details on other tasks can be found in their respective separate reports. The other reports focus on the following topics:

1. **Task 1:** Assessing the potential of RFNBOs and recycled carbon fuels (RCFs), as defined in RED II, over the period 2020 to 2050 in the European Union's (EU's) transport sector, including deployment potential, resource competition, and decarbonisation potential.
2. **Task 3:** Developing a framework on additionality in the transport sector, developing different options with a view to determine the baseline of Member States, and measuring additionality in accordance with Article 27, paragraph 3, subparagraph 3 of RED II.

As Section 2.2 explains, RED II lists three cases by which the renewable energy content of RFNBOs can be determined. Each case is associated with various requirements. In this report, the project team further evaluates options and gives recommendations, structured along with the three cases:

- Section 4: Options to fulfil requirements of Case 1 – Average grid electricity
- Section 5: Options to fulfil requirements of Case 2 – Direct connection
- Section 6: Options to fulfil requirements of Case 3 – Renewable grid electricity

Section 2.3 details the assessment methodology for each case.

2.2 Policy context

The RED II has created a legal basis for electricity-based fuels to be used for renewable energy target achievement in the EU. The Directive aims to implement the binding European target of at least 32% renewable energies in final energy consumption by 2030. In contrast to the RED I, which set a target of 20% for the year 2020, RED II does not contain binding targets on the Member State level for the share of renewable energy in gross final energy consumption.

However, Article 25 of RED II defines minimum transport sector renewable energy target (RES-T) shares. According to this article, "Member States shall set an obligation on fuel suppliers to ensure that the share of renewable energy within the final consumption of energy in the transport sector is at least 14% by 2030 (minimum share)." Multipliers are identified for various energy sources (e.g. advanced biofuels, electricity in road and rail vehicles, and renewable fuels in maritime and air transport). The real RES-T share could therefore be lower than the nominal target value while still complying with the target.

To calculate the minimum share in the transport sector, Member States must (in accordance with Article 25.1 of RED II) take RFNBOs into account, including when they are used as intermediate products to produce conventional fuel. RFNBOs are, however, not part of advanced fuels and no double counting is applied nor is a minimum percentage of RFNBOs required. In Article 2 of RED II, RFNBOs are defined as "liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass."

Since RED II was adopted in 2018, RFNBOs and electricity-based fuels in general have received increased attention as an indispensable pillar of decarbonised energy systems. Companies from all sectors, including transport, have announced the development of large-scale projects to produce and use electricity-based fuels. National governments have developed strategies to promote these technologies, and the Commission published its hydrogen strategy in July 2020 (European Commission, 2020). In this strategy, the Commission communicates the target of "installing at least 6 GW of renewable hydrogen electrolysers in the EU by 2024 and 40 GW of renewable hydrogen electrolysers by 2030." It is likely that RFNBOs will not only be a theoretical option for RES-T target achievement but will actually be produced and consumed at a large scale.

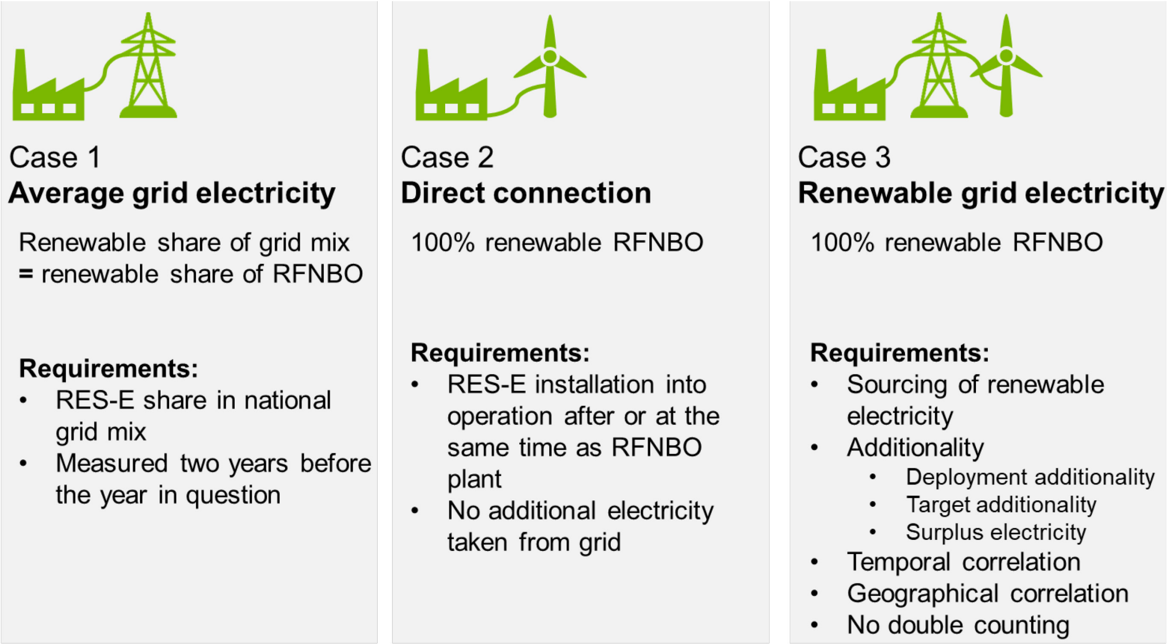
However, a risk with this fast scale-up lies in the fact that the production of RFNBOs requires large amounts of electricity, partly because of high conversion losses. If produced from CO_2-intensive grid electricity, RFNBOs would create significant amounts of CO_2. In Germany, for example, liquid synthetic hydrocarbons based on the current electricity grid mix would cause approximately 780 g of CO_2 per kWh—more than 3 times higher than the 250 g of CO_2 per kWh emitted when conventional fossil gasoline is burned. RED II recognises this fact and states in Article 25.5 that, "the greenhouse gas [GHG] emissions savings from the use of renewable liquid and gaseous transport fuels of non-biological origin shall be at least 70% from 1 January 2021." A separate Delegated Act (DA) will develop details on the GHG savings, but it will be picked up in the discussion of Case 1 (Section 4) when average grid electricity is discussed as energy source for the production of RFNBOs. To avoid rising CO_2 emissions due to the ramp up of RFNBO production, legally binding criteria for RFNBOs are needed. This objective was reinforced in the Commission's hydrogen strategy, which states that the Commission should "work to introduce a comprehensive terminology and European-wide criteria for the certification of renewable and low carbon hydrogen."

RED II paves the way for such criteria by anticipating three cases by which the renewable energy share of RFNBOs can be determined. In two of these cases (Case 2 and 3), the RFNBOs can be counted as fully renewable according to Article 27 of RED II. Figure 1 details these cases.

2.2.1 Case 1

If RFNBOs are produced with the average grid mix, the national electricity mix 2 years before the calculation year is used by default to calculate the RES share of the electricity used to produce the RFNBOs. Only the share of RFNBOs corresponding to the renewable electricity input may be counted as renewable.

Figure 1. Three cases defined by RED II in which RFNBOs can account for the transport sector's RES target



2.2.2 Case 2

The RFNBO may be counted as fully renewable if there is a direct link between the renewable electricity (RES-E) plant and the RFNBO plant, according to Article 27:

> electricity obtained from direct connection to an installation generating renewable electricity may be fully counted as [RES-E] where it is used for the production of [RFNBO], provided that the installation: (a) comes into operation after, or at the same time as, the installation producing the [RFNBO]; and (b) is not connected to the grid or is connected to the grid but evidence can be provided that the electricity concerned has been supplied without taking electricity from the grid.

2.2.3 Case 3

The RFNBO plant sources renewable electricity from the grid, according to :

> Electricity that has been taken from the grid may be counted as fully renewable provided that it is produced exclusively from renewable sources and the renewable properties and other appropriate criteria have been demonstrated, ensuring that the renewable properties of that electricity are claimed only once and only in one end-use sector (DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL, 2018).

Additional specifications are made in Recital 90 of the RED II. When developed, methodology must establish the following renewable properties:

- There is a temporal and geographical correlation between fuel production and the electricity production unit with which the producer has a bilateral renewables power purchase agreement (PPA).

- There is an element of additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy.

For Cases 2 and 3, the Commission plans to adopt a DA by the end of 2021, defining detailed conditions under which electricity for the production of RFNBOs can be counted as fully renewable, as stated in Article 27 of RED II.

RED II does not rule out the possibility that one RFNBO production plant combines these cases. For example, an RFNBO production plant might be fed with RES-E through a direct connection to a wind farm for 2,500 hours per year (Case 2), procure RES-E through the grid for another 3,000 hours (Case 3), and produce non-renewable fuels that do not fall under any of these cases for the remaining 2,000 hours (see Section 3.2).

The economics, the contribution to GHG emission reductions, and the potential market uptake of RFNBOs will depend on the conditions of accepting electricity taken from the grid as 100% renewable. Stakeholders will have diverging positions on the interpretation of the RED II text. For example, the RES-E sector has a natural interest in a stricter implementation of additionality criteria to provide investment certainty for RES capacity. Producers of renewable fuels sometimes advocate softer additionality criteria to allow for low cost electricity input. For this report, the project team bases its methodology on an objective, carefully weighted interpretation of the requirements set by RED II.

2.3 Methodology

This task's goal is to develop a methodology by which the renewable share of electricity consumed for RFNBO production can be determined based on the RED II requirements. As an initial input for this methodology, the project team compiled a long list of options to fulfil each RED II requirement, largely from literature and position papers (see Section 9) and from discussions with consortium experts. Based on these inputs, the project team conducted a high level examination of all options for each case, discussing their strengths and weaknesses. Options from the literature that clearly do not correspond to RED II requirements are mentioned but not evaluated. The high level evaluation of the long list of options can be found in Section 10 and yielded a preliminary selection of options to be further analysed in Task 2 of this project.

These findings and the preliminary selection were discussed with the Commission, the Expert Group on Renewable Fuels, and in a stakeholder event (both on 13 October, 2020). Based on these discussions, the consortium conducted a deeper analysis of the shortlisted compliance options and preliminary recommendations. Input for further analysis included interviews with consortium experts, specific discussions with the Commission, written feedback by stakeholders (industry associations, energy sector companies, and NGOs) after the stakeholder event and bilateral consultations with further experts from industry and academia on topics that required more input. After several iterations, this process yielded the consortium's final recommendations on which options to include in the Delegated Act (DA). This report presents these recommendations.

While conducting research for this project, the authors received stakeholder perspectives on the topic through discussions with the Dutch government, the German federal government, the European Federation for Transport and Environment, the Bellona Foundation, TenneT, National Grid, CertiQ, Germany's Federal Network Agency, Red Eléctrica de España, RECS International, Royal Dutch Shell, BP, Greenpeace, BDI, BOW, Air Products, and VDMA. Written input provided by stakeholders is listed in Section 9.

3. Aspects concerning all cases

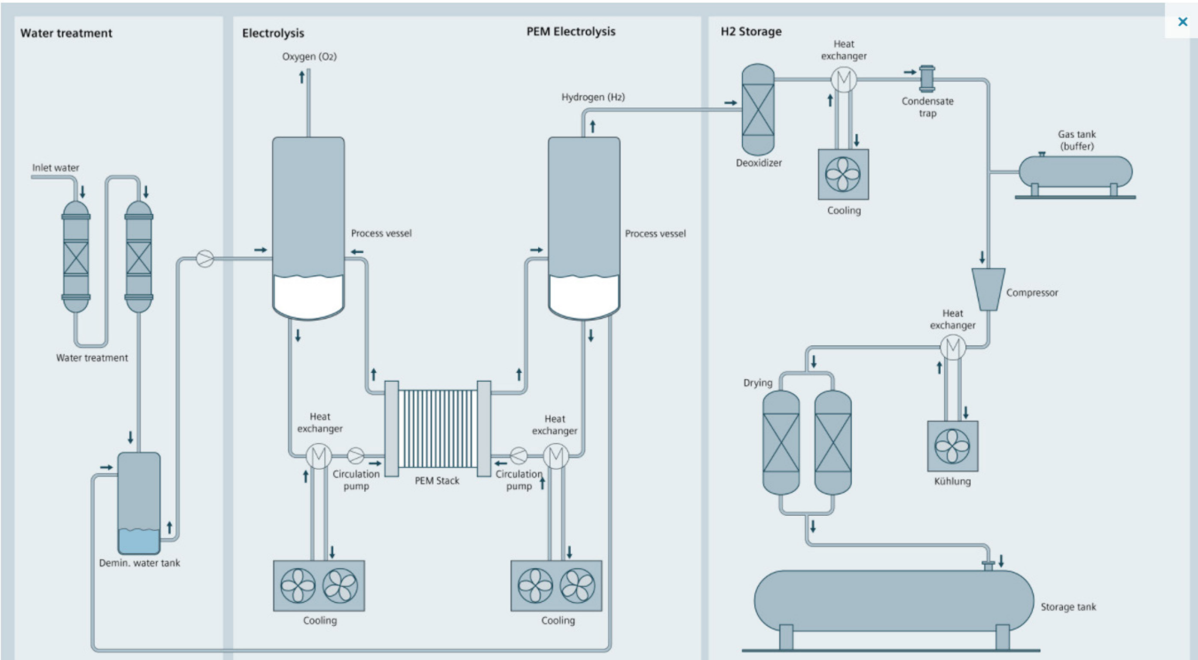
3.1 Energy consumption system boundaries

System boundaries for the energy consumption of RFNBO production facilities must be identified to determine the volume of energy (such as electricity) that is supposed to be verified as renewable. Various definitions of system boundaries are found in literature and commercial publications, making comparisons between different technologies challenging.

In general, a basic water electrolysis unit will typically consist of:

1. **A hydrogen production unit** (i.e. an electrolyser)
2. **Auxiliary systems** (e.g., gas and water separators, gas drying system, power supply systems, and electricity storage units; see Figure 2)

Figure 2. Overview of the components of a typical water electrolysis production facility

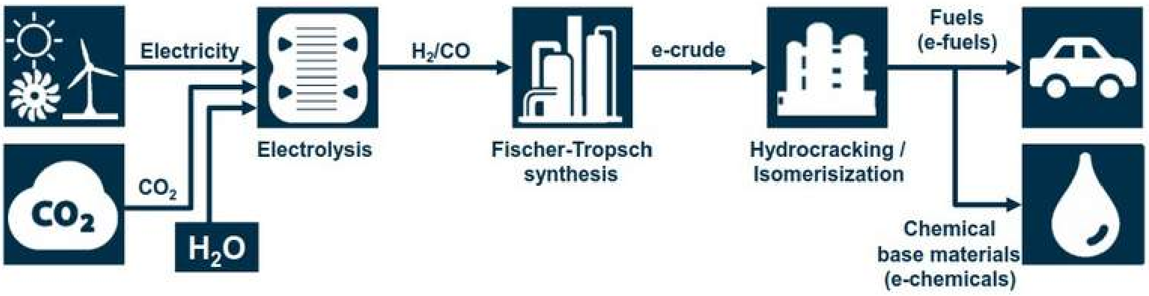


Source: Siemens, 2020

Producing synthetic fuels from hydrogen involves further synthesis processes and (in most cases) utilisation of captured CO_2. Hence, the additional system components, depending on the specific plant set-up, can include the following:

- **Further synthetisation units** producing variety of RFNBOs (e.g. Fischer-Tropsch, Sabatier reaction, dimethyl ether synthesis, hydrotreating).
- **CO_2 delivery units** (e.g. onsite or offsite CO_2 capture and conditioning, direct air capture unit); Figure 3 presents a simplified schematic.

Figure 3. Simplified schematic for synthetic crude oil production



The renewability and energy consumption of the produced RFNBO depends on the total plant electrical and heat consumption and the origin of the used heat and CO_2. The project team discusses all of these aspects in the following subsections.

3.1.1 Electricity consumption

In general, all electricity input (in $kWh_{el\ in}$) for energy equivalent final output (for instance in $kWh_{H2\ out}$ or $kWh_{CH3OH\ \ out}$) should be taken into account. Furthermore, consistent reporting on either lower or higher heating values is necessary to prevent calculation mistakes.

The project team recommends that all electricity consumption related to the main hydrogen production unit, auxiliary systems, further synthetisation units, and CO_2 delivery units (discussed in more detail below) are considered. The project team recommends excluding onsite process-irrelevant electricity consumption from the calculation total (e.g. worker facilities' electricity consumption). There must be a pragmatic way to deal with cases where non-final RFNBO intermediate (e.g. e-crude; see Figure 3) are mixed onsite or offsite with fossil intermediates to generate the final products (e.g. kerosene or diesel) used in transport. Especially when the final production steps are located offsite, requiring that the used electricity comes from RED II-compliant RES-E might be impractical. Such methodology for allocating energy consumption to different products will probably be part of the DA pursuant to Article 28 of RED II.

Finally, the end of the system boundary should be defined as the point of RFNBO exit from the main production units and auxiliary systems. Practically, this point of RFNBO exit could be external compression system, a pipeline or other transport medium, or onsite storage.[1] There may be notable exceptions to this definition, including the case of mixing intermediate products, as outlined previously.

3.1.2 Heat consumption

The treatment of heat input when determining an RFNBO's renewable energy content is not directly obvious from Article 27, which only explicitly refers to electricity. However, this absence should concern the Commission as it may constitute a loophole in RFNBO

[1] Similar to the hydrogen benchmark system boundary under the EU Emission Trading System (European Commission, 2019).

renewability requirements. The project team describes some of the main aspects of heat in the RFNBO production in the following paragraphs.

Depending on the specific production route, heat input can present a significant share of the total energy consumption of an RFNBO facility. Starting with water electrolysis, there are two main production technologies—polymer electrolyte membrane (PEM) and alkaline (ALK)—and two emerging technologies—high temperature electrolysis (HTE) and anion exchange membrane AEM). While PEM, ALK, and AEM have insignificant heat requirements, the HTE process is designed so heat and power inputs are interchangeable to an extent. HTE requires significant heat input for the process to function (typically around 150˚C).[2] Thus, HTE operators could choose an increased heat input that could come from non-renewable resources (e.g. by using an onsite natural gas burner) to use less RES-E.[3]

Various further synthethis processes can be used. Most of these processes are exothermic by nature, meaning that no (or only minimum) heat input is required for the synthesis to take place. However, there are exceptions to this rule, such as the Fischer-Tropsch process, which is endothermic and thus requires significant heat input.[4] Similar to HTE, if non-renewable resources provide the heat input, the GHG intensity of the produced RFNBO could increase significantly.

Finally, CO_2 capture and conditioning typically require significant heat input that should not be disregarded. The heat demand of a CO_2 capture process is largely determined by the capture technology (e.g., chemical absorption or adsorption) and the thermal energy needed to regenerate the capture medium. For industrial CO_2 capture using leading chemical absorption technology, which is currently at the highest technological readiness, thermal demand goes up to around 3 GJ/tCO_2. For direct air capture (DAC), some of the more developed technologies can be fully electrified (e.g., high temperature aqueous solution DAC), whereas others can require heat input up to 9 GJ/tCO_2 (Fasihi, Efimova, & Breyer, 2019).

When considering CO_2 capture from industrial sources and the subsequent purification standards needed for CO_2 utilisation in catalytic processes,[5] thermal energy demand will likely constitute most of the energy demand of this step at around 70%. Electricity makes up the rest of the energy demand.[6] For DAC processes, this thermal energy share can vary between 0% and 80% depending on the DAC technology (Fasihi, Efimova, & Breyer, 2019). Further energy consumption related to CO_2 capture and utilisation varies significantly, depending on use of the CO_2 (i.e. on the particular synthesis process). Conversely, the energy source for CO_2 capture and conditioning and the source of the CO_2 (fossil or biogenic) will have significant impact on the overall GHG intensity of the produced RFNBO. Furthermore, the treatment of onsite versus offsite CO_2 capture and conditioning needs to be outlined. Section 3.1.3 discusses CO_2 further.

Heat integration is an important consideration for all of the previous information. Heat integration refers to situations where two or more industrial process are thermally coupled (e.g. through a heat exchanger network) to increase overall system energy efficiency. While

[2] The internal system temperature in HTE typically exceeds the input heat temperature several times. In literature, the high internal temperature is sometimes mistaken for required input heat.

[3] An in-depth analysis of RFNBO production processes can be found in the Task 1 report for this project.

[4] However, a significant part of this energy can also be recovered and used downstream.

[5] In catalytic processes, CO_2 purity needs to be close to 100%, with impurities, such as oxygen, largely removed.

[6] This analysis has been performed for three points of CO_2 capture: a cement plant, a blast furnace, and a steam methane reformer. Based on Guidehouse calculations.

heat integration is desirable from a system efficiency perspective, it may result in situations where RFNBO production processes are heat integrated with processes using fossil energy.

The simplest way to ensure heat inputs do not have adverse effects on RFNBOs' GHG profile would be to require the heat input for RFNBO production to come from renewable resources. RFNBO operators could, for instance, procure the equivalent part of the heat consumption for RFNBO production via biomethane GOs[7] or employ onsite biomass cofiring or geothermal energy. The Commission should investigate how to best treat heat inputs in RFNBO production.

3.1.3 CO_2 capture and conditioning

CO_2 (or CO) inputs are required in most RFNBO synthesis processes. CO_2 can be of non-renewable (fossil) origin or of renewable origin (e.g. from bio-feedstocks or DAC). The origin of the energy inputs and of the CO_2 are important for the overall GHG footprint of RFNBO production. For instance, electricity sourced for the power-to-methane process would have to be between 4 gCO_{2eq}/kWh-62 gCO_{2eq}/kWh (the lower end of the range is well below most RES-E sources) to have a positive climate impact compared to natural gas, if the source of CO_2 used for the process is of fossil origin (Blanco, et al., 2020).

Depending on the specific technology, various amounts of heat and electricity are required for carbon capture and conditioning . Heat (steam) will likely make up the majority (approximately 70%) of the demand, and electricity will likely account for the rest. It is critical to consider energy inputs of carbon capture and utilisation (CCU) relative to the energy consumption of the entire synthesis process, including hydrogen production. This differs vastly depending on the specific steps that occur after hydrogen production. To illustrate, if the project team considers a power-to-methane route using CO_2 from industrial capture, ALK electrolysis would make up about 89% of the energy required, with CO_2 capture and purification supplying the remaining 11%. Considering the average power share for CO_2 capture and purification energy demand, this implies a power share of around 4% in this step.[8] For DAC, the power demand for CO_2 capture and conditioning could significantly increase this power share.[9]

Finally, as with the electrical and heat consumption of CO_2 capture and conditioning, it is important to distinguish between onsite and offsite systems. The electricity input would be included and heat treated according to the Commission's decision for onsite systems. For offsite systems and subsequent CO_2 import, the situation would be different. The two basic proposals and one hybrid option for the treatment of offsite capture and conditioning, and their pros and cons, are as follows:

- **Option 1: Exclude all electrical consumption of offsite capture processes.** This option is simpler and has fewer hurdles to advance the CO_2 capture processes. Since the 70% overall GHG emission reduction still would have to be upheld, as RED II stipulates, the power and heat used in the processes would likely still have to come

[7] For example, **Vertogas** in the Netherlands and the **Green Gas Certification Scheme in the UK**. In time, **ERGaR** may provide a RED II-compliant, EU-wide option.
[8] The 4% power share refers to processes up to to the methanation reaction, which requires additional energy input. Based on Guidehouse analysis. Electrolysis efficiency assumed 65% (lower heating value, LHV), 0.5 tH_2 and 2.75 tCO_2 per 1 tCH_4 as inputs for the methanation reaction. Energy consumption of the methanation reaction is excluded from the calculations.
[9] If DAC is used, this share could come up to 22% of total energy demand if a fully electrified high temperature aqueous solution system is used. The assumed electricity consumption of such a system is 5.5 GJ/tCO_2. (Fasihi, Efimova, & Breyer, 2019).

from low emission sources. Offsite systems might be put at an advantage compared to onsite systems to fully comply with RED II RES-E sourcing requirements.

- **Option 2: Include all electrical consumption of offsite capture processes and decide on a benchmark value for imported CO_2 (MWh/tCO_2).** Under Option 2, the facility that captures the CO_2 would not have to directly comply with RED II for its electricity sourcing, but the purchaser (the RFNBO operator) would have to demonstrate compliance. If such an approach is chosen, the project team recommends only applying sourcing of renewable electricity and additionality requirements, as including requirements for temporal and geographical correlation would be impractical. Under this option, some operators might choose to use more heat and less power for CCU (where technology allows), which might not be desirable from a GHG perspective.
- **A hybrid option could include allowing Option 1 for CCU based on biogenic and DAC sources and Option 2 for CCU based on fossil sources.** Use of biogenic CCU options, including DAC, could be incentivised (albeit only offsite) through this hybrid. On the other hand, DAC is an electricity-intensive process. Hence, the renewability (and perhaps also additionality) of the electricity used for CCU should be required in order to to reduce the GHG impact of CCU. CCU processes that use fossil energy would be disincentivised under this option and would more likely turn to CCS decisions. However, it is questionable whether such a provision is empowered under the DA, given that the Act's purpose is to safeguard renewable energy content and not to incentivise certain carbon capture technologies.

Recommendation

All electricity consumption related to the main hydrogen production unit, auxiliary systems, further synthetisation units, and CO_2 delivery units should be considered when applying the methodology to determine RES-E consumption. The project team proposes that the end of the system boundary is defined as the "point of RFNBO exit from the main production units and auxiliary systems." This "point of RFNBO exit" could be an external compression system, a pipeline or other transport medium, or onsite storage. The Commission should investigate how to best treat heat inputs in RFNBO production. Finally, the project team recommends that the Commission consider that the energy inputs for CO_2 capture and conditioning could be taken into account in a way that incentivises the use of renewable carbon inputs for RFNBO production.

3.2 Combination of cases

Stakeholders often interpret the three cases in RED II (see Section 2.2) in a way that means each RFNBO production plant operates under one of the cases. However, RED II does not explicitly prohibit producers from claiming renewability of the fuel produced in one plant by applying different cases. Therefore, the project team expects that a single RFNBO production asset can, in theory, combine all three cases and even produce non-renewable fuels that do not fall under any of the three cases. In practice, the project team expects the following combinations to be relevant:

- Producers may find it attractive to combine Cases 2 and 3 with a direct connection between RES-E and RFNBO plants. This combination would allow them to source some of their electricity with reduced administrative burden via Case 2 and increase the plant's load factor with grid-sourced RES-E via Case 3.

- Combinations of Case 2 or 3 with non-renewable fuel production are likely to be used as an operational fallback option for producers when they cannot source RES-E but also cannot (fully) shutdown the plant for technical reasons. This is because non-renewable fuels would have higher costs than revenue potential.[10] An exception may be nuclear-based low carbon hydrogen based, which may be marketable for a premium in the future. RFNBO producers could choose this production path in times of no renewable infeed.
- Case 1 will probably be used without combining it with other cases in countries with close to 100% RES-E share as it requires much less evidence from RFNBO producers than Cases 2 or 3. If the RES-E share is lower, however, the following combinations may make sense for operators:
    - High nuclear shares lead to a low GHG emission factor of electricity supply, but also a low RES-E share (e.g. France). In such cases, RFNBO producers probably would still apply Case 2 or Case 3 to sell 100% renewable RFNBO. As a fallback option, they could use Case 1 because they would still be able to produce partly renewable RFNBO under Case 1 (see Section 4.1.2). It should be noted that the non-renewable part of RFNBOs produced under Case 1 cannot be counted as renewable by applying Case 3 on top of Case 1.
    - Even in some countries with relatively high RES-E shares, Case 1 probably cannot be applied. RFNBO producers will have to produce under Cases 2 or 3. When Case 1 becomes applicable in a country due to increased RES-E shares, producers will likely continue to produce under Cases 2or 3 because they have already set up a direct connection or a PPA. They would likely produce under Case 1 only in times where Cases 2 and 3 are not possible—typically the hours with the least RES-E infeed and high GHG electricity footprint. This could be avoided by banning combinations with Case 1. However, such adverse effects could be seen as temporary phenomena before the electricity system is entirely GHG-neutral.

Other combinations with Case 1 are less likely because it requires much less evidence from RFNBO producers than Cases 2 or 3. If RFNBO production occurs in a country where the GHG emission factor of grid electricity already allows for the application of Case 1, producers will therefore probably only produce under Case 1.

Table 1 summarises the potential combinations of cases and the anticipated likelihood that RFNBO producers will combine them.

Table 1. Potential combination of RFNBO production cases

	Case to be combined with			
	Case 1	**Case 2**	**Case 3**	**Non-renewable production**
Case 1 – Average grid electricity		Only attractive to combine in countries with high nuclear shares or countries that are slightly above the GHG threshold		No need to combine, can always use Case 1

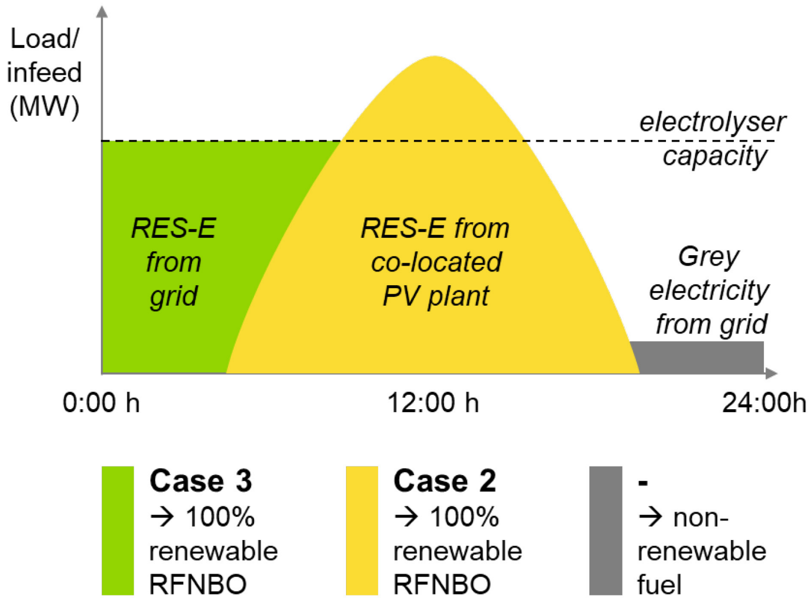
[10] Assuming only electricity costs of 6 ct/kWh and 75% electrolyser efficiency, cash costs for non-renewable hydrogen would be 8 ct/kWh. Gray hydrogen from steam methane reforming costs around 3-6 ct/kWh; this price would likely be attainable for hydrogen without a green premium.

	Case to be combined with			
	Case 1	**Case 2**	**Case 3**	**Non-renewable production**
Case 2 – Direct connection			Potentially attractive to combine for Case 2 settings	Fallback option if plant cannot be shut down in times with no RES-E supply or for low carbon H_2 production
Case 3 – Renewable grid electricity				

Source: Guidehouse

Figure 4 illustrates an electrolyser consuming electricity from a directly connected PV plant under Case 2 during the day. In the early morning, the lack of PV infeed is filled with RES-E consumption from the grid, fulfilling Case 3 requirements. However, in the afternoon and night, RES-E spot prices are too expensive, so the RFNBO producer runs the asset at minimum load, producing hydrogen that is not compliant with RED II criteria and cannot be marketed as renewable.

Figure 4. Illustrative example of an electrolyser combining Cases 2, 3, and non-renewable fuel production.



Source: Guidehouse

The additional administrative burden to audit and certify RFNBO volumes produced under different cases in one plant should be minor. Cases 2 and 3 will need the time of production tracked for each unit of RFNBO (see Sections 5.2.2 and 6.3.3). Another reason for the relatively small administrative burden is that the RFNBO shares claimed through Cases 2 and 3 are 100% renewable. Once they have been produced, they can be marketed and tracked as one batch; only non-renewable fuel needs to be handled separately.

3.3 Target additionality

The concept of additionality means RFNBO production consumes RES-E that would not have been produced in the absence of RFNBO production. This prerequisite is essential for 100% renewable RFNBOs or else their production cannibalises RES-E volumes that would have been used by other consumers who then consume non-renewable electricity.

On a micro level, RES-E consumers can achieve additionality by deploying further RES-E assets or using surplus RES-E. This is reflected in two of the three RFNBO production cases expected by RED II:

- **Case 2 – Direct connection:** Additionality is implicitly contained by requiring RES-E capacities to come into operation at the same time or after the RFNBO capacity under consideration (see Sections 5.1.1 and 5.2.1).
- **Case 3 – Renewable grid electricity:** Additionality is explicitly anticipated in Recital 90 (see Sections 6.1.2, 6.4.1, and 6.4.2).

However, under a legal framework that only requires deployment additionality on a micro level, the stimulated additional RES-E generation for RFNBO production would be regarded as a contribution to meeting RES targets set in RED II and in national policies. This could lead to Member States reducing the ambition of their public support schemes while still meeting their targets. Under these circumstances, the efforts of RFNBO producers would not lead to full additionality of RES production compared to current RES deployment trajectories. This target additionality should also be required at an international level, andthe EU should not allow RFNBOs produced by RES-E to be imported if the exporting country has less RES-E for its own consumption.

The calculation rules of the Article 3 target demonstrate this issue. According to Article 7.4(a):

> Final consumption of energy from renewable sources in the transport sector shall be calculated as the sum of all biofuels, biomass fuels and renewable liquid and gaseous transport fuels of non-biological origin consumed in the transport sector. However, renewable liquid and gaseous transport fuels of non-biological origin that are produced from renewable electricity shall be considered to be part of the calculation pursuant to point (a) of the first subparagraph of paragraph 1 only when calculating the quantity of electricity produced in a Member State from renewable sources.

The common interpretation is that the energy content of RFNBOs is never included in the overall RES share, even if it is produced in a third country from renewable electricity. Instead of the energy content of RFNBOs, RES-E for domestic RFBNO production is included in the overall RES target.[11] These target achievement measurements bear a high risk that deployment additionality does not translate into target additionality (explained in Section 6.1.2) as the electricity used to generate the RFNBOs is fully counted towards the RES target.

This means that RED II does not make any explicit requirements for target additionality and any option that aims to effectively ensure target additionality will likely require an adjustment

[11] The implementation of Art. 7 in the latest version of SHARES (2019) deviates from this interpretation by treating domestically produced RFNBOs based on their energy content. This is in line with Option 1b.

of RED II. The options discussed in Sections 3.3.1 and 3.3.2 provide more stringent ways to foster target additionality that always require an adjustment of RED II.

Target additionality does not target the producers of RFNBOs, but rather Member States. Given that RES targets are not binding at the Member State level, tightening target additionality requirements on RES expansion would remain an option. Therefore, the following options could guide Member States to meet their non-binding RES targets, taking target additionality into account.

3.3.1 Ex post approaches

Ex post approaches use empirical data to check whether the determined RES targets have been achieved, which means that the targets are reviewed retrospectively. The project team identified two ex post options as suitable to ensuring a higher degree of target additionality, refered to as 1a and 1b:

- Option 1a: RES-E used for RFNBO production is excluded completely when calculating RES targets, and all RES-E used in RFNBO production must be additional.
- Option 1b: This option is the same as Option 1a, but the RFNBO final energy consumption is included in the calculation of the RES target so only conversion losses fall under the additionality requirement.

Both options foster a higher degree of target additionality, as the full RES-E consumption of RFNBO production is not counted towards the RES targets and needs to be covered by RES-E generation above the target trajectory. Option 1a is strict and completely excludes all RES-E consumption of RFNBO production and RFNBO consumption from the calculation of the RES share. Option 1b calculates the energy content of the RFNBOs into the RES share. In such a framework, only the energy lost due to conversion needs to be additional. In Option 1a, the whole electricity consumption of RFNBO production must be additional.

3.3.1.1 How could it be implemented?

Target additionality would need to be implemented at the Union level and in Member States as it does not directly address economic operators. The most significant step in implementing ex post options is to adapt Article 7 of RED II:

- For Option 1a, the RES-E used to produce RFNBOs must be subtracted from the numerator and denominator of the RES share calculation.
- This is also carried out in Option 1b, whereas in Option 1a, the energy content of the produced RFNBOs is added to the numerator and denominator.

Given the adaptation of RED II, both options must confirm that the quantities of electricity consumed by RFNBO production are measured and reported to the responsible authority. Option 1b also requires a measurement of the RFNBO energy quantity. Both types of data can be collected by the RFNBO producer via meters. As a fallback option, the RES-E consumption of RFNBO production could also be calculated based on conversion factors and on RFNBO energy content or vice versa.

3.3.1.2 What are risks and challenges?

The main challenges of these options are political, as an adjustment of RED II requires the approval of the EU Parliament and the EU Council. In addition, Option 1a and Option 1b (to a lesser extent) would reduce the incentives of the Member States to support RFNBOs since high RFNBO production would require more RES-E generation for RES target achievement. This point is significant to the concept of target additionality and is strengthened by a more restrictive definition of target additionality.

Implementing Options 1a and 1b does not pose major challenges to data collection, as only a few additional datasets are needed. Electricity meters can be installed without much effort and, since RFNBOs are usually fed into a supply chain regulated by the energy tax and other national regulations (e.g. CO_2 taxes, national ETS), these energy flows would also be monitored without the implementation of Option 1b in most cases. RFNBO producers have no incentives to manipulate their data, since it has no impact on their operational business, simplifying the process. RED II already requires the measurement of the energy content of RFNBOs and RES-E to calculate renewable shares. The effort required for such a monitoring, reporting, and verification (MRV) system seems limited, but Member States should implement the new calculation methodology of the RES share as soon as possible and check the progress annually to clearly visualise their progress towards the RES share target. Doing so would reduce the risk of non-compliance with the set targets.

Option 1b appears more promising given the challenges of adjusting the RED II and that Member States have less incentive to support RFNBOs when target additionality is set to be more restrictive. Moreover, it would be misleading to completely ignore RFNBOs under Article 3, as it is a renewable fuel by definition.

3.3.2 Ex ante approach

In this option, the EU-wide and national RES share targets are adjusted ex ante by including the expected RES-E consumption of RFNBO production in RES targets, which leads to an increased RES target. The original RES target, which does not include RFNBO production and so does not include RES-E for RFNBO production in the numerator and denominator, is extended by the electricity consumption of the projected RFNBO production by adding this in the numerator and denominator. This extension leads to an increased RES target. The ex post verification of RES target achievement is completed as described in Article 7 of RED II (taking all RES-E into account for domestic production).

3.3.2.1 How could it be implemented?

Target additionality would need to be implemented at the EU level and in Member States as it does not directly address economic operators. For this option, the guidelines for reporting national targets in the National energy and climate plans (NECPs) in the Governance Regulation would need to be adapted to clarify that the national RES targets should be topped up by the RES-E required to produce RFNBOs. Whether this requires modification of the legal text or whether it could be part of the Commission’s feedback to the draft NECP revisions in 2023 necessitates legal analysis, which is out of the scope of this report.

In addition, reliable and consistent forecasts of the electricity consumption of RFNBO production must be available. The first step of implementation is to determine which projections can be used by Member States. NECPs and European Council (EUCO) scenarios could be useful for this. However, current versions of these documents do not have the level of detail required, which should be taken into account when revising the NECPs and the scenarios. Given the expected electricity consumption for RFNBO production, Member States must increase their RES targets by this electricity consumption and report it to the EU. Accounting for all Member States, the EU-wide RES target should then be adjusted as well. Unlike the two ex post options, this option does not require the implementation of an MRV system at the RFNBO plants.

3.3.2.2 What are risks and challenges?

The biggest challenge with the ex ante option is that it sets targets based on forecasts. Assuming the forecasts are perfect and there is no deviation from existing consumption, this option is equal to Option 1a in terms of additionality achieved. However, if there is a discrepancy between existing and projected consumption, the two options are not identical. In the event of higher than expected RES-E consumption in RFNBO production, a Member State under the ex ante option may have met its RES targets. Under Option 1a, it may have missed them, and target additionality would not be guaranteed. Under the ex ante option, a Member State has the incentive to keep the forecasts of RFNBO production as low as possible while simultaneously supporting production, since any higher RES-E consumption of RFNBO production than expected does not lead to higher RES share requirements. High requirements and regular forecast updates could reduce the risk, but this would require additional effort in turn. Although NECPs and EUCO scenarios could serve as data sources, the official documents are not detailed enough to derive the electricity consumption of RFNBO production and need be updated in the context of NECP revisions.

Given the uncertainty of whether RES-E consumed in RFNBO production was actually additional and that a repeating process in terms of modelling and RES target adjustment would be necessary to ensure additionality, an ex ante option does not seem feasible to ensure target additionality.

Recommendation

If RFNBOs are to be counted as fully renewable in Cases 2 and 3, RES-E targets should fully reflect the additional RES-E demand for RFNBO production. The project team recommends addressing this target additionality in RED II's next revision. This change can be made by accounting for RFNBOs under the Article 3 RES target based on the calorific value of RFNBOs rather than counting the RES-E input for RFNBO production for target achievement. Under the Article 3, additionality would not have to be required for the entire electricity consumption of the RFNBO production, only for the conversion losses during production. The additionality requirements would compensate for the poor energy efficiency of RFNBO production.

3.4 RFNBO consumption in sectors other than transport

3.4.1 Green hydrogen in refineries

As laid out in Article 25.1, RFNBOs also contribute to RES-T target achievement "when they are used as intermediate products for the production of conventional fuels." From today's view, the main application of this regulation will be the use of hydrogen in refining. Refineries are among the largest hydrogen consumers, using it for desulphurisation of fossil oil & gas. This hydrogen is largely produced from natural gas. With RED II, there is an incentive to replace this with renewable hydrogen produced from electrolysis because this change does not require any further changes in transport infrastructure.

Establishing a solid methodology for the renewable energy accounting of RFNBOs in this context is crucial since fuel producers are very interested to employ this ability, partly motivated by meeting Fuel Quality Directive RES-share targets. BP and Royal Dutch Shell, for example, were conducting major pilots in their German refineries even before the applicable RED II provision became effective through national legislation.

3.4.1.1 Criteria for RFNBOs

The methodology outlined will refer mainly to hydrogen electrolysis for hydrogen use in refineries because this application is the most prominent. Should other RFNBOs also be employed as intermediates in conventional fuel production, the same logic could be applied.

As a working hypothesis, any requirements defined regarding the renewable energy content of RFNBOs consumed directly in transport should equally apply to RFNBOs consumed as intermediates in fuel production. This requirement would mean that an electrolyser at a refinery would have to fulfil the requirements as discussed for the three cases previously (see Sections 4, 5, and 6) if the hydrogen produced was to be counted as renewable.

Not differentiating requirements depending on RFNBO end use is logical because all requirements discussed in this report are targeted at the production side. As described in Section 3.1, the scope of DA requirements would apply up until the point of RFNBO exit from the main production units. This approach would also create a leaner regulatory framework, as opposed to a scenario where different requirements are introduced for RFNBO production depending on where the fuel will be sold, such as a fuelling station or a refinery. When detailing the options of the three cases in the further course of the project, this working hypothesis will be revisited to examine whether any reasons arise that might necessitate additional guidance for RFNBOs used as intermediates.

3.4.1.2 Target achievement calculation

When calculating the RES-T share pursuant to Article 27.1, the renewable energy content of RFNBOs used as intermediates in fuel production is expected to be added to the numerator as if these RFNBOs had been consumed in transport directly. For the denominator, however, Article 27.1(a) suggests that the energy use in conventional fuel production is not contained (see Figure 5, A). This calculation would mean that consuming natural gas for hydrogen production in refineries does not influence the RES-T share negatively while using renewable hydrogen for the same process would have a positive impact.

A mathematically clean alternative would be to include hydrogen use in refineries (fossil- and renewable-based) into the denominator when calculating the RES-T share for the target defined in Article 27 (see Figure 5, B). This calculation would lead to two issues:

- First, it may require an adaption of the corresponding RED II provisions.
- Second, hydrogen consumption in European refineries amounts to around 70 TWh (CertifHy, 2015), which represents around 2% of the EU transport sector’s final energy consumption.

This calculation methodology would mean that including hydrogen in refineries in RES-T targets would make target achievement harder, not easier—at least until renewable hydrogen gains a significant share in refineries’ total hydrogen consumption.

A third option would be to add only the renewable hydrogen consumed in refineries to the denominator (see Figure 5, C). In contrast to Option B, this calculation would mean that hydrogen in refineries would be a pure bonus for RES-T targets with no effect if fossil-based hydrogen is used. It would only be a 100% bonus and not a mathematically infinite bonus as in Option A. This option may also require an adaption of the corresponding RED II provisions.

Figure 5. Options to include RFNBOs used as intermediate products to produce conventional fuels (in this example, hydrogen in refineries) in RES-T share calculation

Source: Guidehouse

3.4.2 Renewability requirements across sectors

The methodologies this report proposes, specifically in Cases 1, 2, and 3, formally apply only in a specific case. RFNBOs must fulfil these requirements if they are to be counted towards the RES-T target set out for Member States in RED II Article 25. Assuming that RFNBOs will only be used in the transport sector if incentivised by policies and that Member States will design their RFNBO policies in a way that it benefits RES-T target achievement, it is likely that RFNBOs consumed in the EU transport sector will have to comply with the DA.

This means that the DA by right does not apply to RFNBOs consumed (e.g. in the electricity sector, buildings, or industry). The Commission's hydrogen strategy recognises this gap and announces "a comprehensive terminology and European-wide criteria for the certification of renewable and low carbon hydrogen" (European Commission, 2020). This terminology is supposed to be based on "existing EU Emission Trading System (ETS) monitoring, reporting and verification" and "the provisions set out in the RED," referring to the DA for which this report develops recommendations. Some Member States have also called for cross-sectoral requirements for RFNBOs (AT, DK, ES, IE, LU, PT, 2020).

Establishing EU-wide, cross-sectoral renewability criteria for RFNBOs is desirable for several reasons:

- Many RFNBOs, such as hydrogen, methanol, or methane, will probably also be consumed outside the transport sector. RFNBO producers will likely serve customers across sectors but should be required to fulfill only one set of renewability requirements. RFNBO producers should not market fuel as renewable to consumers in the transport sector if it does not qualify (e.g. in industry as a green product).
- A fuel's renewability is defined by its production process; its end use is not relevant. There is no technological reason to differentiate requirements depending on the end use sector.

- The creation of a liquid single market (e.g. for green hydrogen) would be hindered if there were several types of green hydrogen traded, depending on the end use sector.
- The transport sector is expected to account only for a certain share of RFNBO consumption in the future (see Task 1 of this project). To avoid negative effects from RFNBO production, such as new GHG emissions, all sectors need to have binding renewability requirements for RFNBOs.

There are, in theory, several regulatory levers in RED II to make such criteria binding. They do, however, most likely require changes to the legal text of the Directive:

1. If sectors other than transport used hydrogen or its derivatives and claimed them as renewable heating & cooling (H&C), the methodology in the DA could be applied when calculating the renewable share of RFNBOs consumed.
2. A future RED revision could hypothetically result in a change of the Article 7 calculation logic, as discussed in Section 3.3. The calorific value of RFNBOs consumed in the transport sector would be counted towards the overall target and not RES-E input used for RFNBO production, as it is currently. The renewability of RFNBOs could be determined using the DA's methodology.

Recommendation

EU-wide, cross-sectoral renewability criteria for RFNBOs should be introduced to ensure transparent, liquid markets and sustainable RFNBO ramp-up. The DA pursuant to RED II Article 27.3 should be a basis for this. If hydrogen or its derivatives were used in sectors other than transport, the provisions of the Act should be applied to determine the renewable energy content of these fuels. Should hydrogen or its derivatives be counted towards the Article 3 target in the future, the criteria could also be applied.

4. Case 1 – Average grid electricity

4.1 Case description and requirements in RED II

RED II describes the requirements underlying this case precisely in Article 27.3 as "where electricity is used for the production of [RFNBOs], either directly or for the production of intermediate products, the average share of electricity from renewable sources in the country of production, as measured two years before the year in question, shall be used to determine the share of renewable energy." This section elaborates on the details of this case and discusses related questions.

The RES-E share in the electricity mix determines the part of the RFNBO's renewable content that is counted towards the RES-T share, and only the renewable percentage is counted towards that share. This differs from Cases 2 and 3, which elaborate on rules under which the energy content of RFNBOs may be fully counted towards the RES-T share. The following sections describe the requirements laid out in RED II for Case 1.

4.1.1 Average electricity

Case 1's definition is specific in Article 27.3. It states that the average share of electricity must be used to determine the share from the production of RFNBOs and that this average must be determined from the values 2 years before the year in question. This rules out other options to establish the renewable energy share, such as the use of marginal electricity generation.

RED II does not specify where this renewable energy share must be measured, whether in generation or consumption of electricity. However, the targets set down in RED II to reach 14% minimum share of renewable energy in the transport sector by 2030 are set in consumption. For consistency with this target, the average share required in Case 1 should also be set in consumption.

4.1.2 Minimum GHG emission savings

Article 25.2 of RED II states that "the greenhouse gas emissions savings from the use of [RFNBOs] must be at least 70% from 1 January 2021." As the other two cases lead to RFNBOs that are produced with 100% RES-E, emissions resulting from electricity consumption are likely only relevant for Case 1. A separate DA will detail this requirement and set out the fossil fuel comparator for RFNBOs (date of publication for the DA is currently uknown). This requirement is relevant as an additional criterion for Case 1, as it links the grid emission factor to the use of RFNBOs.

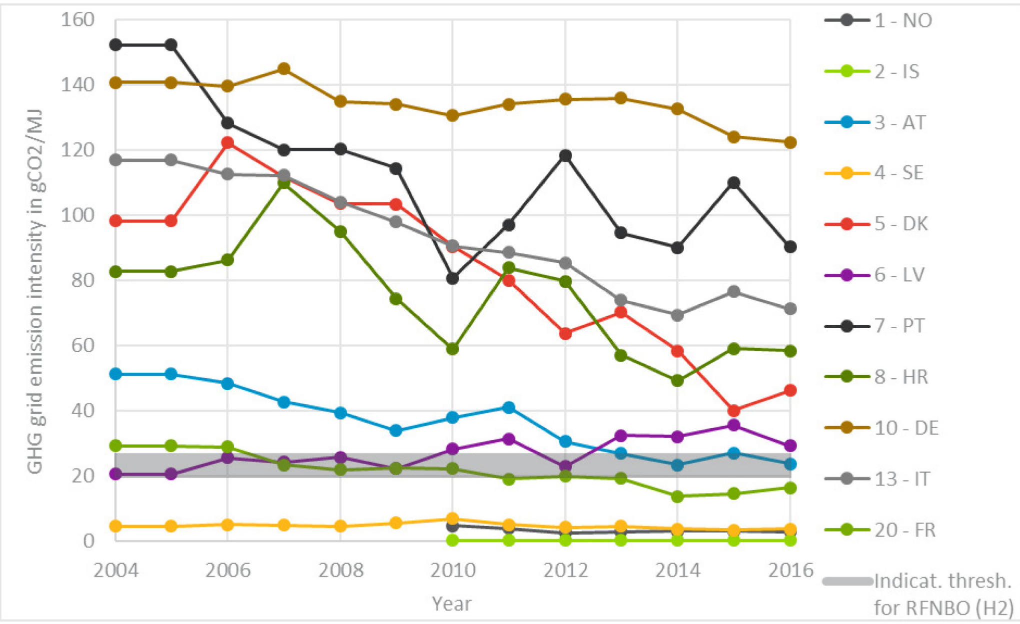
The emissions from RFNBO use are at least those occurring during production if transport and distribution are not considered. In Case 1, the emissions during production are determined by the grid emission intensity and the conversion losses. The grid emission intensity is given by the overall power generation mix, considering all renewable and non-renewable generation. It can also be lowered by a higher share of nuclear power.

Aspects of a renewable share in production should not be confused with the GHG avoidance that needs to be achieved. RED II notes only a certain share of the production under Case 1 qualifies as RFNBO, depending on the average share of RES-E in the grid mix, as Article 27.3 specifies. However, the GHG emission avoidance considers the total production, including that of the non-renewable RFNBO, so the grid emission intensity applies to the RFNBO fraction of the fuel that is produced and the non-renewable fraction.

Figure 6 summarises the emission intensity of grid electricity for selected European countries. The countries are numbered according to their RES-E share as reported in Eurostat's SHARES tool. An indicative threshold range is provided to determine if a product is RFNBO. This range is derived by assuming a fossil fuel comparator of 94 gCO_2/MJ (as set out for biofuels in Annex V C.19 of the RED II; this is only an indicative reference), applying the 70% savings required by Article 25.2, and assuming an efficiency of 75% (the approximate value for hydrogen; see Task 1 of this project for more details). The threshold is noted as a hashed area to reflect the uncertainties in this approach. Of Member States listed, only France and Sweden, with large shares of nuclear power (and renewables Sweden's case), undercut this threshold, with Austria likely above. Norway and Iceland also undercut the indicated threshold.

A separate DA currently in development deals with questions surrounding GHG emission savings and RFNBOs. The points above show that under Case 1, RFNBO production will not be possible in most EU Member States as long as electricity sector emissions are not reduced significantly.

Figure 6. Grid emission factors for selected European countries.[12]



Source: Enerdata

[12] Numbering in the legend refers to the shares of RES-E as reported in the SHARES tool and discussed below. An indicative range for a threshold for RFNBO production is given (see text for more details). A separate DA is being developed that explicitly deals with GHG emission savings; this figure serves also as an indicative reference.

4.1.3 System perspective on Case 1

Under Case 1, RFNBO producers can claim the RES-E share of the national electricity mix if the minimum requirements for GHG emission savings, as set out through Article 25.2, are met. According to RED II, the fulfilment of further criteria is not necessary. Case 1 will not be applicable in most Member States in the near future. The low accounting burdens laid on Case 1 in RED II should therefore be seen in light of a fully decarbonised future energy system. However, until this state is reached, the application of Case 1 results in several drawbacks from a system perspective. Removing these drawbacks would require changes to the regulatory design of Case 1, implying a change to RED II itself (Case 1 is not treated in the DA pursuant to Article 27.3). The following paragraphs describe the drawbacks in Case 1 and point out how these could be circumvented.

RED II has designed Case 1 to be a simple, default case of renewable content for RFNBO production, and this simplicity stands against these drawbacks. Therefore, the negative effects described below could be accepted, as they will become problematic in a transitional period between the time when Case 1 can be applied in more countries until the European power system is fully based on renewable sources.

4.1.3.1 Total GHG emissions

RFNBO production causes higher electricity consumption and leads to an increase in GHG emissions in the electricity system due to the fossil peak load capacities, which need to be activated earlier. In countries with RES-E share close to 100% (i.e. Norway and Iceland), peak load generation may be renewable as well, but in the European perspective, peak load mostly relies on fossil resources. The emission-free part of fuel production can mitigate emissions in the transport sector, but this does not apply to the non-renewable part of the fuel.

Adding additional RES-E to the system, either induced by the Member State (target additionality, see Section 3.3) or induced by the RFNBO producer (deployment additionality, see Sections 6.1.2, 6.3.1, and 6.3.2), is an option to reduce these additional emissions. This option would bring the requirements for a revised Case 1 closer to those of Case 3, which contradicts the purpose of Case 1 as a simple and default case.

4.1.3.2 RES-E double counting

When applying Case 1 for RFNBO production, the RES-E used may be claimed twice: By the RFNBO producers connected to the grid and by any electricity consumer using the GOs of RES-E plants in the same country. For example, an RFNBO producer in Norway could produce RFNBOs based on the grid mix. The fuels would be considered largely renewable, based on the rules described previously. At the same time, RES-E GOs from Norway are used for green electricity products for end consumers in the EU (e.g. EV users). Statistically, some of those energy volumes are also sold to consumers as RFNBOs.

GOs are not used to track national RES-E shares or targets and target achievements. Instead, their main purpose lies in disclosing the origin of electricity to customers. In that sense, there are two different perspectives on RES-E shares in an electricity mix. According to the GHG Protocol, in corporate GHG reporting, these perspectives are referred to as the location-based method, which reflects the average GHG intensity of grids on which energy consumption occurs, and the market-based method. The latter reflects emissions from electricity that companies chose. It derives emission factors from contractual instruments, including GOs (World Resources Institute, 2015).

From a national target perspective there is no real risk for double counting; however, intertwining the commercial perspective and electricity consumers can lead to confusion and perceived double counting. To avoid this, three approaches are possible:

- GOs could be made a requirement for RFNBO producers claiming the national RES-E share.
- RFNBO producers could be required to refer to the country's residual mix as determined by the Association of Issuing Bodies (AIB).[13] A residual mix represents the national mix of uncertified electricity (where GOs are not claimed by other parties).
- If the producer is supplied with electricity through a third party, this supplier would need to ensure that they use GOs for the RES-E share they claim to supply (market-based method).

RED II does not require all the approaches; it would need an extension of the regulation. Following these options confirms that used RES-E is only marketed to consumers once. However, from the producer perspective, the first option would cause additional costs, whereas the second option would likely result in lower RES-E shares and higher GHG intensity of the electricity supply. The third option (if applicable) would not necessarily have negative effects as all electricity suppliers are obliged to provide the information anyway within the EU. All options pose some burden and counteract the simplicity of Case 1.

4.1.3.3 Level playing field

The different requirements for RFNBO production between Cases 1, 2, and 3 will create different incentives for Member States to invest in RFNBO production, depending on whether the electricity mix is adequate to meet the GHG requirements for Case 1. Options to alleviate these differences would need greater requirement alignment between the cases. For Case 1, this alignment could mean the use of GOs, the use of the national residual electricity mix, or even the requirement of additionality, as in Case 3. All of these options would require an extension of RED II.

4.2 Options to meet the requirements in RED II

As the description of Case 1 and the requirements indicate, RED II is very specific regarding Case 1. There is no room to define criteria as it is not part of the DA. RFNBO production under Case 1 needs to comply with the GHG emissions savings threshold of Article 25.2, but this threshold is regulated by the DA, which is currently being developed on this topic. Renewable energy content is determined by the average RES-E share, as set out in Article 27.3 of RED II. The following sections discuss the SHARES tool as an option to determine this share. In addition, the project team discusses electricity imports, which may or may not be renewable. The project team also looks at the possibilities to apply this case in countries outside of the EU, in the case of RFNBO imports.

[13] The residual mix is available from: Association of Issuing Bodies. "European Residual Mix." https://www.aib-net.org/facts/european-residual-m

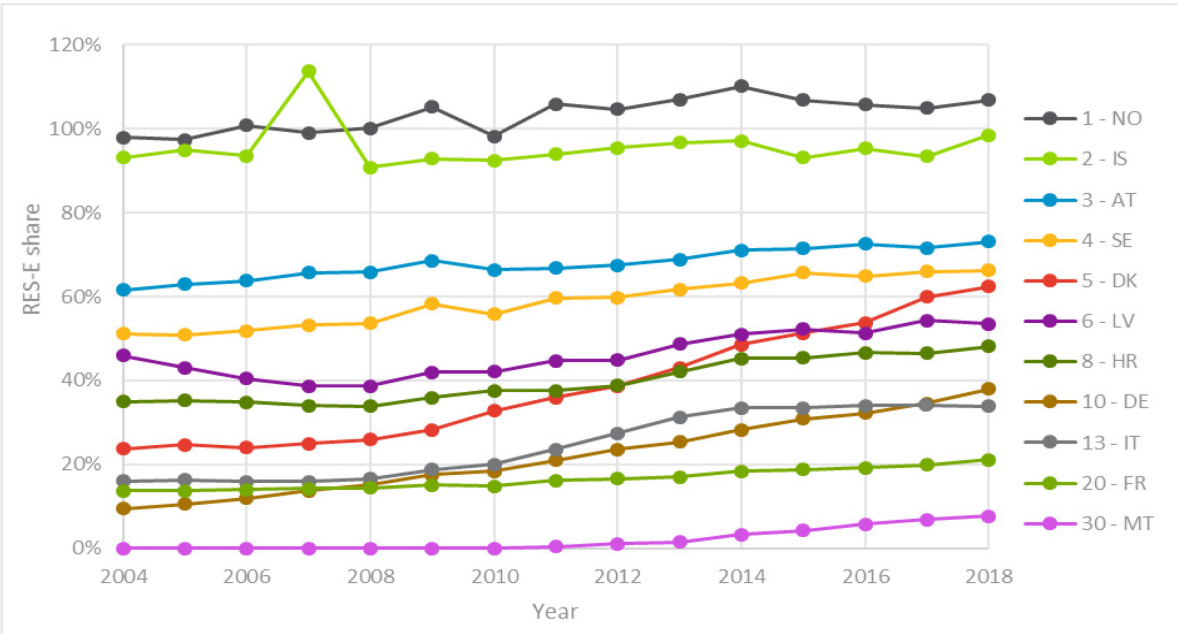
4.2.1 Determining the average share of RES-E

The requirements outlined Section 4.1.1 suggest the data collected by Eurostat's SHARES tool[14] are an adequate database to determine the share of RES-E[15]. This suggestion is consistent with the legal basis for the data provided by this tool in Directive 2009/28/EC, the predecessor of RED II. The tool reports and makes available the shares of renewable energy per Member State. For the data provided under SHARES, Member States each go through the same methodology to calculate the required values and data and are therefore easily comparable.

An alternative to the data in the SHARES tool could be the data available from the European Network of Transmission System Operators for Electricity (ENTSO-E) transparency platform. ENTSO-E also provides data on electricity generation in Europe, which can be broken down by the different generation types. Due to data gaps, the quantities reported in this data source are often significantly lower than those reported by Eurostat and so are less appropriate.

The SHARES tool reports the share of renewable energy in terms of consumption. The manual to the tool specifies how this share is determined: gross final consumption of electricity from renewable sources divided by gross final consumption of electricity. The numerator is defined in the SHARES calculation as the gross electricity production from renewable sources, specifying accounting rules for the different energy sources. The denominator is given by gross electricity production from all energy sources plus total imports minus total exports of electricity. Figure 7 presents the RES-E share of an illustrative country selection as given by the SHARES tool.

Figure 7. Share of renewable energy in electricity as reported in SHARES for selected countries reporting values in the tool (considering EU Member States, UK, NO, IS[16]).



[14] Available online from Eurostat as database and Excel sheet: Eurostat. "SHARES (Renewables)." https://ec.europa.eu/eurostat/web/energy/data/shares.

[15] The data is directly available online from: Eurostat. "Share of energy from renewable sources." https://ec.europa.eu/eurostat.

[16] The legend also gives the rank of countries for the year 2018.

Source: (EUROSTAT, 2019)

4.2.2 Considering imports of electricity

The data published under the SHARES tool defines electricity consumption from renewable sources in a country as equal to the production in that country (in line with RED II Article 7.2), not considering the RES-E share in imports and exports. The numerator is defined as the sum of production from the different renewable energy sources (as defined by Article 7.2 of RED II) while the denominator is given by gross electricity production from all energy sources plus total imports minus total exports of electricity. By this definition, the RES share in the net import of electricity is not counted towards the share of renewable energy in the country of consumption.

However, cross-border electricity trade is an important aspect of the electricity system and will become increasingly important as RES-E shares in the electricity system rise and interconnections serve to stabilise the grid. Different or additional data sources need to be tapped to consider these aspects in the RES-E share of consumption. This sourcing would require a timed log of electricity consumption, generation from different sources, and electricity import and export. A homogeneous dataset that shows all this information is not available. However, RED II states that the average share in the electricity grid shall be used and that the SHARES tool (set up through the predecessor of RED II) is meant to document this share. Retaining the definition underlying the SHARES tool and counting net imports as non-renewable is a viable option that aligns with RED II.

4.2.3 RFNBO imports from non-EU countries

This section considers how Case 1 methodologies can be applied in non-EU countries. Some neighbouring countries of the EU are also covered under the SHARES tool, which is true for the UK,[17] Norway, Iceland, Montenegro, Serbia, Albania, North Macedonia, Bosnia and Herzegovina, Turkey, and Kosovo (under UNSCR 1244/99). These countries (except for the UK, in the future) can be treated as EU Member States when calculating the renewable share of RFNBOs under Case 1.

Other countries could be covered by using international databases or national data. The following list includes several international databases, mentioning their advantages and shortcomings:

- **International Renewable Energy Agency (IRENA)** collects and publishes data on the use of renewable energies in many countries around the world. The data is free to anyone and in an online database. The RES-E share is provided in the form of an Excel tool, which is available online.[18]
- **The Renewable Energy Policy Network for the 21st Century** publishes an annual report, the *Renewables Global Status Report*.[19] The report is free to download and gives a table with an overview of the share of renewables in electricity production 2 years before publication. The main topic of this table are RES-E targets and the number of countries for which RES-E shares are reported as limited. For those EU

[17] The UK will continue to send data to Eurostat until the end of 2020. Afterwards, another data source will need to be used, such as that provided by the Department for Business, Energy and Industrial Strategy.

[18] International Renewable Energy Agency. IRENASTAT Online Data Query Tool. 2020. **https://www.irena.org/Statistics/Download-Data**.

[19] The Renewable Energy Policy Network for the 21st Century. Renewables 2021 Global Status Report. 2021. **https://www.ren21.net/wp-content/uploads/2019/05/GSR2021_Full_Report.pdf**.

countries that are in the table, the differences to the data published in SHARES is less than 5%, but it does reach more than 10% for some counties.

- **The International Energy Agency (IEA)** publishes data on renewable energies for Organisation for Economic Co-operation and Development (OECD) countries. Due to differences in accounting wind and hydro power plants, the data reported under IEA is not equal to the data reported under SHARES, but differences remain below 5% for most countries. IEA data is accessible through a membership, typically via an institutional library account, as the access also provides publications. Below, the project team explores the data that is freely available online.[20]
- **The World Bank** provides data on RES-E generation for all countries in the world in its database. However, data for some countries differs significantly from the Eurostat data. The delayed data provision is a problem, as the most recent data is currently for 2015. Using the World Bank data as an option is not explored further below.
- **Enerdata** is a commercial database that collects energy-related data from different sources, including the IEA database.[21] Enerdata allows queries to the database through an online interface and indicates the data sources and any special notes on the data. RES-E is available separately by technology, except for bioenergy, which is not broken down to electricity generation. Due to Enerdata's dependence on IEA data for OECD countries, the difference to SHARES is at a similar value as IEA values.

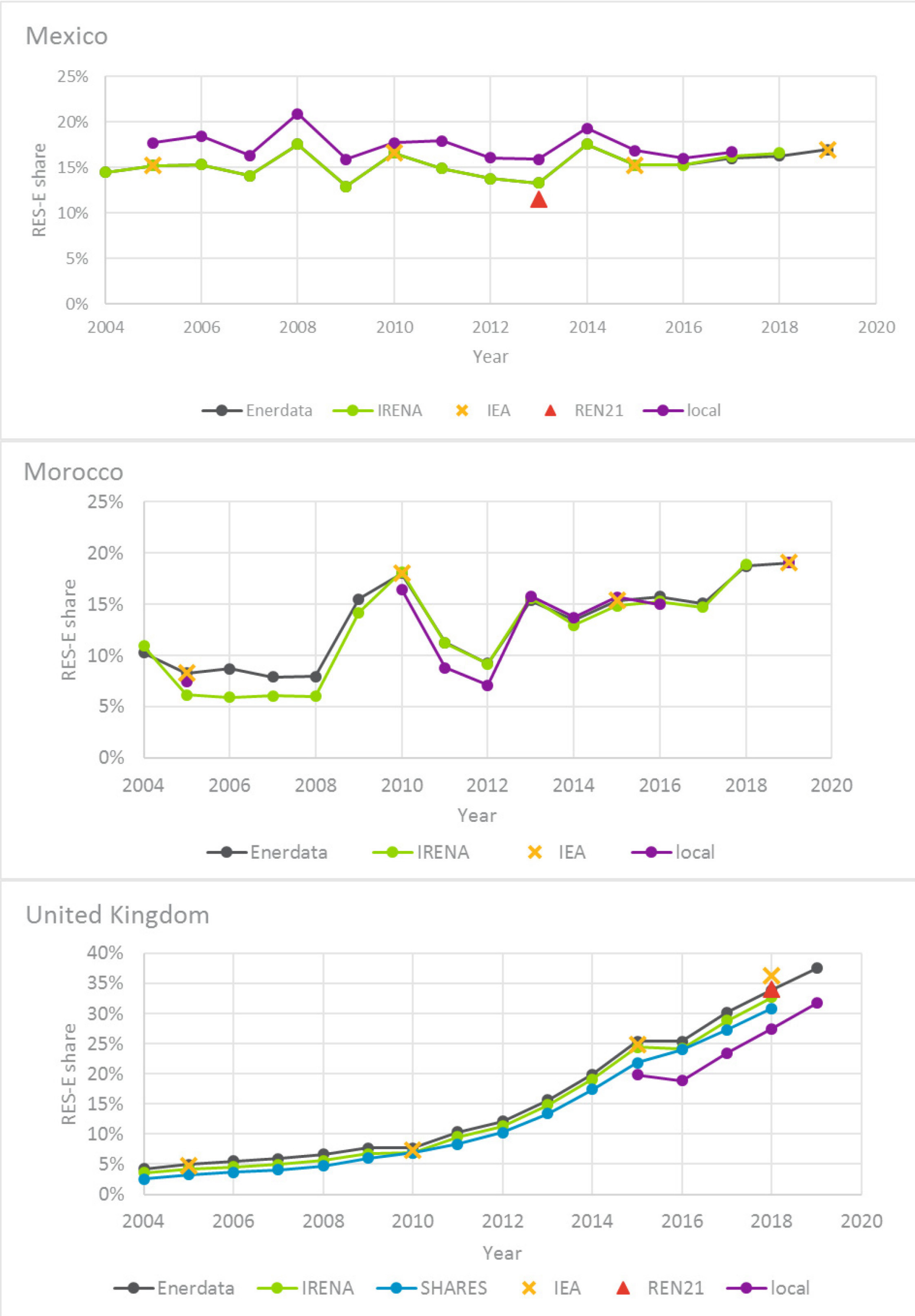
Examining four possible RFNBO-producing countries shows the difficulties in applying Case 1 outside the EU if data availability is limited or if data collection methods are different. Figure 8 shows four exemplary countries (Mexico, Morocco, the UK, and Uruguay). For each, the project team shows data from the sources listed above (where available) and a local source.[22] For the UK, the project team also gives the data as reported under SHARES.

[20] International Energy Agency. "World Energy Balances." **https://www.iea.org/data-and-statistics/data-product/world-energy-balances**

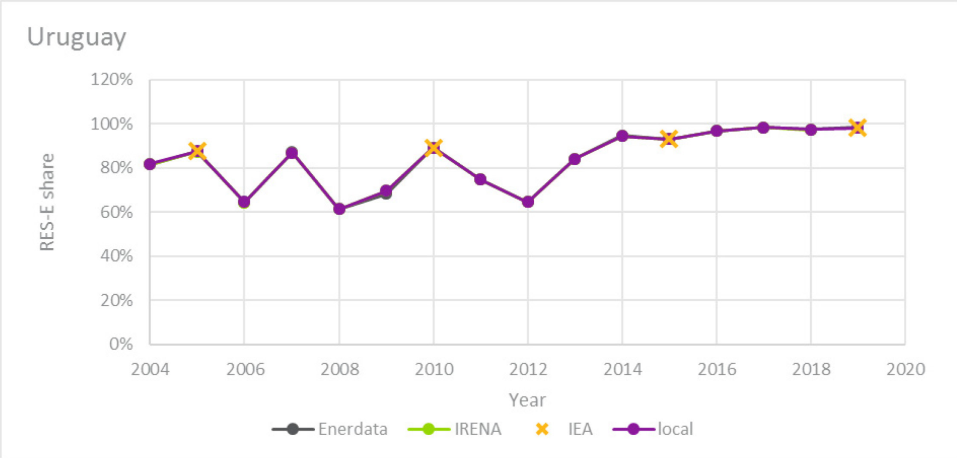
[21] Enerdata can be reached online at **https://www.enerdata.net/**.

[22] Mexico reporting through its Secretaría de Energía, reporting through its Energy Information System. Sistema de Información. **http://sie.energia.gob.mx/bdiController.do?action=temas&language=en**; Morocco reporting through the International Atomic Energy Agency from Office National de l'Electricité et de l'Eau Potable. International Atomic Energy Agency. *Morocco 2018.* **https://www-pub.iaea.org/MTCD/Publications/PDF/cnpp2018/countryprofiles/Morocco/Morocco.htm**; UK reporting through its Department for Business, Energy & Industrial Strategy. Department for Business, Energy & Industrial Strategy. "Energy Trends: UK electricity." 28 October, 2021. **https://www.gov.uk/government/statistics/electricity-section-5-energy-trends**; Uruguay reporting through its Ministerio de Industria, Energía y Minería. Catálogo de Datos Abiertos. "BEN - Generación de electricidad por Fuente." **https://catalogodatos.gub.uy/dataset/miem-generacion-de-electricidad-por-fuente.**

Figure 8. RES-E share as reported by different sources for Mexico, Morocco, the UK, and Uruguay.[23]



23 For Uruguay, the different time series overlap. See text for details.



Source: Secretaría de Energía, International Atomic Energy Agency, Department for Business, Energy & Industrial Strategy, Ministerio de Industria, Energía y Minería

As the data collection in Figure 8 demonstrates, the four exemplary countries show a different history of RES-E shares. Uruguay has been reaching high shares during the last 15 years, while the UK has seen strong growth during the same time. Mexico and Morocco show stagnant shares of roughly 20%. The different sources show similar values, though differences remain in most countries. The international databases from IRENA, IEA, and Enerdata are consistent, but do not report values identical to SHARES. The offset to the local data sources shows that details matter. In the UK, the local source reports only major power producers, which leads to lower values than in the international databases and SHARES. In Mexico, the local value refers to the gross electricity generation, which is slightly different than the value reported by SHARES for EU Member States (RES-E generation divided by net consumption). For Morocco, values of the local source are only available up to 2016, which limits usability of the data for Case 1. For Uruguay, all values are identical.

Different standards in data collection and reporting need to be considered when applying Case 1 in non-EU countries. The methodology underlying the SHARES tool is specific to the EU. To achieve the same meaning of the value reported as RES-E share and subsequently in the share of renewable energy in RFNBOs, producers in third countries should be required to apply the same methodology as under SHARES. The necessary data to calculate SHARES compliant RES-E shares is available in most countries. The calculation could be carried out by an RFNBO producer or independent certifying bodies if Case 1 is to be applied. This application could be facilitated by providing a standardised SHARES tool template, which calculates only the RES-E share (while SHARES also reports on other sectors) and is made available online by a pertinent EU body.

5. Case 2 – Direct connection

5.1 Case description and requirements in RED II

Case 2 is characterised by the presence of a direct connection that links an RFNBO facility and an installation generating and supplying RES-E. Case 2 is one of two ways for RFNBO producers to claim a 100% RES-E share per the DA in RED II. This section looks at the peculiarities of this case. Article 27.3, subparagraph 5 of RED II sets two preconditions that must be fulfilled to fully count the supplied electricity as renewable: the first regarding the renewable energy installation's operation start and the second regarding the electricty sourcing.

5.1.1 Timing of RES installation commissioning

RED II requires that the installation generating RES-E "comes into operation, after or at the same time as, the installation producing the [RFNBOs]." By requiring a synchronised or later starting date, RED II aims to prevent electricity from already existing and older RES installations from being used. Instead, the electricity would need to be supplied by newly deployed RES installations. According to the project team's interpretation, this requirement shall indirectly ensure the additional electricity consumption induced by the RFNBO facility is met by the additional RES-E generation.

The wording of this precondition leaves room for interpretation on several aspects:

1. What serves as the best proxy to determine the point in time when the RES-E asset comes into operation?[24]
2. Can existing renewable installations become eligible for the status of coming into operation a second time in case they are subject to a major overhaul (e.g. repowering a wind turbine)?
3. What time interval should the criteria of at the same time be evaluated?

To create planning certainty for RFNBO producers, any ambiguities concerning the answer to these questions must be resolved in the DA. They are discussed in Section 5.2.1.

5.1.2 Supply exclusively via direct connection

RED II requires that the "installation generating renewable electricity is not connected to the grid or is connected to the grid but evidence can be provided that the electricity concerned has been supplied without taking electricity from the grid." The consumption for which the RFNBO producer claims a 100% RES-E share must exclusively be supplied by a RES installation via direct connection and no additional electricity can be taken from the grid. Critically, this requirement evokes two distinct options regarding the grid connection status.

[24] For the high level evaluation of the long list of options, please refer to section 10.3.2.1.

While Case 2 is considered a single case, claims for a 100% RES-E share can occur in to subcases:

- **Isolated direct connection:** In this subcase, the RFNBO-producing facility is exclusively connected to a RES installation, which is not connected to any other off-taker. In principle, the generated renewable electricity is either consumed by the electrolyser or curtailed. However, it appears likely that such a case would incorporate electricity storage to increase the available amount of the electrolyser's full load hours. Without storage, the electrolyser would have to face the full intermittency of the coupled renewable energy installation. According to stakeholders, "[D]irect connection of the electrolysers to RES-E installations in complete off-grid systems is still very challenging and the technical and economic feasibility of this model is not demonstrated yet" (EDF, 2020). Others expect a prominent role for electrolysers and RES-E installations in complete off-grid systems (Hydrogen Europe, 2020a). One illustration for this subcase could be an offshore wind power park that is combined with an offshore RFNBO facility. The resulting RFNBO would be transported either via ship or pipeline.
- **Direct connection plus grid connection:** In this subcase, the RES installation is connected via a direct line to an RFNBO facility and to the public electricity grid. The operator of the RFNBO-producing unit must provide evidence that the electricity used to produce the RFNBOs was not imported from the grid but instead generated by the RES installation linked via the direct connection. The consumption for which the RFNBO producer claims a 100% RES-E share via Case 2 can at no time exceed the infeed of the connected RES installation. Because there is a connection to the grid in this case, the RFNBO producers provide the required evidence by demonstrating the temporal correlation of the fuel production and the RES-E production. This temporal correlation must be strict to comply with the obligation to produce without taking electricity from the grid. Excess electricity not consumed by the RFNBO facility can be exported to the grid. For potential residual consumption that exceeds the generation of the RES installation, the RFNBO producer can refer to Case 3, claim partial renewability via Case 1 options, or produce fuels that do not count as renewable under RED II (see Section 3.2 on combining cases).

5.1.3 Definitions

In addition to the requirements, two terms in the RED II article are particularly important for this case and should be clearly defined in the upcoming DA. After deliberation with the steering committee of this project, the project team agreed on the following definitions:

- A **renewable electricity installation** can include a single or several RES-E generation units of the same type (e.g. solar or wind park) or several units of a different type that are joined together into a virtual power plant (VPP) (e.g. a PV installation coupled with a wind and geothermal power plant).
- A **direct connection** between the RES and the RFNBO installation is what distinguishes Case 2 from Cases 1 and 3. The project team considers the definition of a direct line in Chapter I, Article 2 of Directive 2019/9448 as synonymous to direct connection: "A 'direct line' means either an electricity line linking an isolated generation site with an isolated customer or an electricity line linking an electricity producer and an electricity supply undertaking to supply directly their own premises, subsidiaries and customers."

This definition thus provides two options to set up a direct connection:

- **Direct connection between two isolated facilities:** This option mandatorily excludes any other ineligible[25] power plants linked to the facilities. Otherwise, it would enable producers to exploit the simple methodology presented in subsection 5.2.2.1.
- **Direct connection between "an electricity line linking an electricity producer and an electricity supply undertaking to supply directly their own premises, subsidiaries and customers":** This option provides much more flexibility because it does not imply that no other installations (electricity-consuming or producing) are connected to this electricity line. For example, an electricity company that relies exclusively on RES-E but also operates a small municipal electricity grid could connect its RES installations via a direct line to an electrolyser located just before the connector to the transmission grid. However, from the project team's point of view, it suggests that the connection is self-owned by either the RFNBO producer or RES facility.

Given that the term direct connection has not yet been defined in EU legislation, there is a large degree of freedom for the Commission. In general, while every direct connection could be defined as a grid or microgrid, not every grid qualifies as a direct connection. A certain rigidness in the definition of a direct line is required to ensure the geographical proximity of both facilities when the facilities are not isolated. Linking the definition of direct connection with the ownership of the respective electricity line would allow for a clear distinction between a grid and a direct connection.

While respecting those premises, the project team has identified fulfilment options for the RED II requirements regarding Case 2 and has evaluated the suitability of the various options. The high level evaluation of the long list of options can be found in the Annex in Section 10. The most promising options are analysed in the following section.

5.2 Options to meet the requirements in RED II

To be eligible to claim renewability via case 2, the RFNBO producer must prove that the installation supplying the electricity is an installation generating RES-E and that both installations are linked via a direct connection. Each is a plant-related requirement that can be checked once for the entire lifetime of the installation.

5.2.1 Timing of RES installation commissioning

RED II requires that the RES-E installation supplying the RFNBO production starts its operation later or at the same time as the RFNBO facility to be eligible for Case 2. The following option to meet this requirement can be applied to both subcases.

This consortium considers the commissioning dates as a suitable time to evaluate when the RFNBO or RES-E installation comes into operation. The commissioning date represents the date on which all relevant commissioning tests and procedures were completed such that the installation is capable of commercial operation. The date is officially determined by the entity responsible for the commissioning process. Beyond this moment, the RFNBO or RES-E producer can start operating their respective installation at any time they choose. Even though the start of the commercial operation might be slightly later, the commissioning

[25] Both conventional and renewable power plants that do not fulfil the timing requirement (refer to 5.1.1) should be considered ineligible.

date appears most suitable because it is already officially determined within the commissioning process that every industrial facility must undergo.

As mentioned in Section 5.1.1, the time interval at which the category of at the same time is evaluated has to be determined. The project team's assumption is that this timing requirement provides some flexibility. The simultaneity does not refer to a single instant in time (e.g. the same second) but instead to a duration compatible with common industrial practice. This timeframe could theoretically be the same date, week, month, or even year.

However, there is an inherent trade-off associated with the duration of the time interval. If it is too short, it entails risks for the economic players involved (as discussed in Section 5.2.1.2). If it is too long, the additional demand induced by the RFNBO facility might not be met by additional RES-E generation. In the worst case, it could lead to additional GHG emissions (see Section 5.2.1.2). From a practical point of view, it appears sensible to assess this trade-off in relation to the market maturity and implement increasing requirements over time (see Section 7).

The DA should address if and under which conditions an older asset can be considered to come into operation a second time within its lifetime. In principle, each asset should only be commissioned once within its lifetime. However, special cases should be considered, with repowering wind turbines as the most prominent example. Repowering involves dismantling the old turbine,s including towers, and subsequently installing new turbines (Wind Europe, 2016); therefore, it constitutes a new investment from a financial point of view. A wind farm coming into operation after repowering should be treated as a new wind farm coming into operation as an entirely new project, even if these facilities may enjoy privileges, such as streamlined permitting, in some Member States.

5.2.1.1 How could it be implemented?

Once the ambiguities related to this requirement are resolved, its implementation is straightforward, both in EU Member States and countries outside the European Economic Area (EEA). RFNBO producers that intend to claim renewability via Case 2 send the commissioning process documents to the certification body responsible for attributing the RFNBO label. The certification body then examines whether:

- The RFNBO installation and the RES-E asset are linked via direct connection.
- The asset supplying electricity qualifies as a renewable energy installation.
- The commissioning date of the RES-E asset is later than the RFNBO's or within the time interval to assess simultaneity. Provided legal feasibility, the project team proposes that both installations are considered commissioned at the same time if the commissioning occurs (ref Section 7.2):
    - Within 12 months during the market uptake phase
    - Within 3 months, once market maturity is reached

If the legal assessment by the Commission reveals that the DA does not have the power to implement a gradual two-phase approach, the time period for commissioning at the same time should directly be 3 months. In this case, the project team does not recommend a compromise solution between the longer and shorter time period because the shorter period already risks being uncompliant with RED II (see Section 5.2.1.2).

5.2.1.2 What are the risks and challenges?

The main risk associated with this requirement is that installation commissioning synchronisation does not necessarily ensure additionality. This requirement is independent of the choice of options to meet it. Instead, it is related to the requirement itself. The explicit requirement of a strictly later or synchronised commissioning date of the RES installation compared to the RFNBO installation is meant to implicitly facilitate the element of additionality that, according to the RED II Recital 90, only needs to be explicitly demonstrated for Case 3. Considering the direct connection between both installations, this appears to be a reasonable safeguard of additionality on first glace. Indeed, in the isolated direct connection subcase it is; the demand induced by the RFNBO installation can only be met by the newly built RES-E installation. However, if the RES-E asset disposes of a grid connection, it is not evident whether its investment decision was based on the existence of the RFNBO facility. This risk is exacerbated by the significantly different lead times for both assets. While it may take 7 years or more for RES-E plants to become operational, RFNBO installations can be planned, built, and commissioned within 2-3 years (EDF, 2020). Thus, the financial investment decision for the RFNBO installation might be based on the future presence of a RES-E asset, which would have been built in any case. Consequently, even if the RES-E asset is commissioned later than the RFNBO facility, the latter's additional demand would not necessarily be met by additional renewable electricity, causing GHG emissions.

In addition, a longer interval to assess simultaneity reduces the likeliness of additionality between both assets. By implementing a longer time interval to evaluate simultaneity of the commissioning dates, this risk increases because RFNBO producers get more time to link up to already planned RES-E projects. Thus, it becomes less likely that the investment decision for the RES-E project is conditioned on the RFNBO installation.

Furthermore, a shorter interval to assess simultaneity increases the financial risks for investors. Strictly shortening this time interval might lead to adverse effects as well. Stakeholder interviews conducted by the project team found that even with proper project planning, there is a significant risk of a temporal mismatch between the commissioning dates of the two facilities. Different technologies, lead times, readiness levels, permitting procedures, and other factors are all potential causes of temporal mismatch. A switch in the sequence of the commissioning dates might occur even though the RES installation was meant to come into operation simultaneously with the RFNBO installation, and the investment decision for the renewable energy plant incorporated the additional electricity demand. In this case, the RFNBO producer would lose the option to claim 100% RES-E via Case 2 unless the start of the RES-E installation's operation is put on hold. This hold would create economic damage due to foregone revenue and additional emissions in the time period where the new RES-E asset could have crowded out a conventional power plant. This trade-off cannot be entirely resolved, yet an approach to increase requirements over time appears sensible to mitigate this risk.

Legal risks regarding the duration of the time interval also remain. Some uncertainty is associated with the project team's proposed approach. From a legal perspective, both time intervals (i.e. the 3- to 12-month duration), but implementing a gradual two-phase approach, in particular, could exceed the legal flexibility of interpreting at-the-same-time parameters and thus not be compliant with the RED II. While the project team assumes that the wording provides some flexibility and refers to a time period instead of a single instant in time, the project team acknowledges that determining said period would be arbitrary to some extent. In any case, a legal assessment to confirm the validity of those time periods appears mandatory.

Recommendation

The project team recommends both subcases, isolated direct connection and direct connection plus grid connection, and verifying the timing requirements of the RES-E and RFNBO operation start via a check of each asset's commissioning date. The project team further recommends a time interval of 3 months within which both assets must be commissioned to be considered as at the same time.

5.2.2 Supply exclusively via direct connection

The second requirement of the RED II for Case 2, electricity sourced from direct connection to a renewable installation, regards the sourcing of the supplied electricity. RED II requires that the RFNBO production facility be exclusively supplied by a RES installation via a direct connection and that no additional electricity be taken from the grid.[26] The project team's consortium proposes to differentiate the options to meet this requirement, depending on the presence of a grid connection.

5.2.2.1 Isolated direct connection

If neither the RES-E nor the RFNBO facility is connected to the grid, the complex can be seen as an integrated, isolated unit with the installations linked via a direct connection. In this case, sourcing from the grid is physically impossible. By providing evidence that the installations constitute an off-grid island, the RFNBO producer proves that no additional electricity can be taken from the grid.

Such an off-grid complex would most likely incorporate an electricity storage facility to deal with the intermittency of the RES-E asset. In this subcase, the presence of a storage facility has no impact on the evidence provision. Because there are no other electricity producers, the entirety of the electricity generation stems from the connected RES-E asset.

How could it be implemented?

The implementation of this fulfilment option is simple: to prove that the electricity it consumes originates solely from the connected RES-E asset, the RFNBO producer must provide evidence that neither the RFNBO nor the RES-E asset has a grid connection. This evidence is sufficient to ensure the electricity can be provided only by the RES-E asset.

In this subcase, the evidence provision for RED II requirements can be independent of the facility's operation. It has an advantage for the involved economic players and for the administrations because it would not require a continuous review of the operation. Instead, the RFNBO producer could claim a 100% RES-E share for the entire electricity consumption over the lifetime of the facility via a one-time certification or at least until the standard operation of the facility changes.

What are risks and challenges?

The main advantage of this fulfilment option—namely, its administrative simplicity for all involved players—might pose a certain risk. Its one-time audit that comes without a continuous stream of documentation could make it more susceptible to fraudulent activities as there might not be regular verification that the originally certified operating mode is still in place. For example, a subsequently installed grid connection could remain unnoticed.

[26] This requirement does not prevent combined cases. Instead, it solely regards the requirements to be fulfilled to claim a 100% RES-E share via the fulfilment options of Case 2 (see Section 3.2).

Periodic inspections of the operating mode of the RFNBO and the connected RES installation might be required.

One future challenge might regard how to deal with the expansion of already existing off-grid RES-E installations. Article 14 of the RED II on capacity increases in the context of joint projects states that “units of energy from renewable sources imputable to an increase in the capacity of an installation shall be treated as if they were produced by a separate installation becoming operational at the moment at which the increase of capacity occurred.” Given that the already existing RES-E asset is not compatible with the requirements of the RED II, one would have to check whether the added RES-E asset produces enough electricity to source the RFNBO installation on its own. Theoretically, this off-grid subcase would also require smart metering.

Recommendation
For the isolated direct connection subcase, the certification body should verify the off-grid status of the RES-E asset and the RFNBO facility, ensuring the latter is indeed exclusively supplied via a direct connection.

5.2.2.2 Direct connection plus grid connection

In the direct connection plus grid connection subcase, the fulfilment option to ensure the RFNBO facility is exclusively supplied via direct connection includes using smart metering to measure the electricity consumption of the RFNBO installation and the electricity generation of the linked RES-E asset. Claiming 100% RES-E should be possible for precisely the electricity for which the time-series data of both facilities matches. Consumption and generation smart metering becomes necessary once there is a grid connection because additional consumers outside of the system boundaries of the RFNBO plant might be supplied by the direct connection (see Section 3.1). Once there is such an additional consumer and electricity is sourced from the grid, it can no longer be determined whether the additional consumer induces the demand for grid electricity or if the RES-E asset does not produce sufficient RES-E to supply the RFNBO facility. Smart metering of demand and supply would solve this issue.

Theoretically, if there was not any other consumption apart from the RFNBO plants, it would be sufficient to measure residual demand at the grid connection point. However, because no consumption other than from RFNBO plants is rather unlikely and smart metering is common practice, even for medium-sized RES-E assets and for all RFNBO facilities, the project team’s proposed approach does not appear to pose particular challenges.

The granularity of the required temporal matching is critical to determining that the electricity sourced is not sourced from the grid. The higher the temporal resolution, the more accurate this verification option becomes and the higher the effectiveness for RED II compliance. A 15-minute resolution, which can be achieved with current household-grade smart meters, appears appropriate to ensure no grid consumption.

The project team’s proposed approach does not require RFNBO producers to strictly follow the generation profile of the connected RES-E asset. The matching solely affects the RES-E that can be claimed via Case 2. RFNBO electricity consumption on top of this can be covered through Case 3.

How could it be implemented?

To provide evidence, the RFNBO producer would need to determine that the smart meters deliver the time-series data to the certification body. The measured data would be sent digitally, either in real time or in batches, as long as the transmission is automated in some form to reducee the administrative burden. The certification body checks for which amount of electricity the consumption and generation match. It then confirms the claim of 100% RES-E for precisely that amount. RFNBO electricity consumption that is not matched by simultaneous RES-E infeed would need to be certified as renewable under Case 1, Case 3, or count as non-renewable.

What are risks and challenges?

The main challenge associated with this fulfilment option lies in the required set up of the IT system that enables the data exchange between the involved economic players and the certification body. Implementing such a system that gathers consumption and generation data, assesses the electricity to be considered as 100% renewable, and returns the information to the RFNBO producer might be difficult for some administrations. However, once implemented, this fulfilment option would run mostly on an automated basis and could even reduce the administrative burden for all parties in the long run.

Recommendation

For the direct connection plus grid connection subcase, the project team recommends that the consumption and generation of the RFNBO installation and the RES-E asset, respectively, be gathered via smart metering. The responsible certification body shall then confirm claims of 100% RES-E for precisely the amount of electricity for which the time-series data of both facilities matches. The temporal matching should be evaluated in blocks of 15 minutes.

6. Case 3 – Renewable grid electricity

6.1 Case description and requirements in RED II

RED II Art. 27.3 foresees that for RFNBO production, "*electricity that has been taken from*
RED II Article 27.3 foresees that, for RFNBO production:

> "electricity that has been taken from the grid may be counted as fully renewable provided that it is produced exclusively from renewable sources and the renewable properties and other appropriate criteria have been demonstrated, ensuring that the renewable properties of that electricity are claimed only once and only in one end-use sector."

RFNBO producers do not necessarily need to be directly connected to a RES-E asset (as in Case 2) and can still have 100% of their fuel count as renewable (as opposed to Case 1). However, several requirements apply according to RED II:

Sourcing of renewable electricity (Article 27.3)

Additionality (Recital 90)

Temporal correlation (Recital 90)

No double counting (Article 27.3)

These requirements are presented in more detail in the following sub-sections and justified in Section 6.2; options for their fulfilment are discussed in Section 6.3.

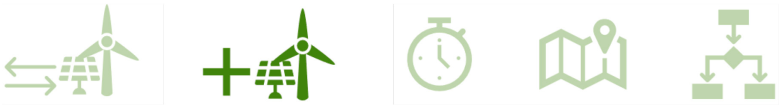
6.1.1 Renewable electricity sourcing

Article 27's provision that electricity consumed under Case 3 must be produced exclusively from renewable sources seems simple to fulfil given the range of RES-E sourcing options available to commercial consumers (see Section 6.2). However, as a standalone requirement, this would not necessarily ensure that RFNBOs are 100% renewable:

- The RES-E claimed by the RFNBO producer (e.g. through a GO) may have been produced in the absence of RFNBO production. In that case, RFNBO production is formally fed with 100% RES-E, but other electricity consumers (e.g. households) would be less renewable by the same amount. From a system perspective, there would be an increase in electricity demand that would be (partially) fed with fossil-based generation.
- The RES-E claimed may have been produced at a different time than the RFNBOs, meaning that RFNBO production may have been fed with fossil-based electricity.
- The RES-E claimed may have been produced far away from the RFNBO plant, which means the RFNBO production may have been fed by fossil generation capacities that were closer or better connected to the plant.

For this reason, there are other appropriate criteria mentioned in Article 27 and subsequently specified in Recital 90 (the rationale for these criteria is further discussed in Section 6.2). These criteria are dealt with in the following subsections of Section 6.1. In Section 6.3, the renewable energy source criterion is merged with the following additionality criterion.

6.1.2 Additionality



The concept of additionality means that RFNBO production consumes RES-E that would not have been produced in the absence of RFNBO production (AT, DK, ES, IE, LU, PT, 2020). This is an important prerequisite for 100% renewable RFNBOs because otherwise, their production would cannibalise RES-E volumes that would have been used by other consumers.

Two dimensions achieve additionality; both are required to ensure full additionality:

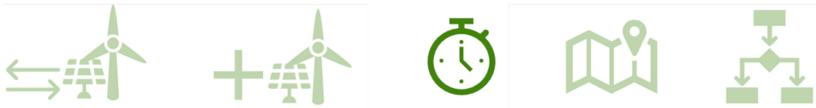
- On a micro level, RES-E consumers can achieve additionality by deploying additional RES-E assets or using surplus RES-E (discussed in more detail in the following paragraphs).
- On a macro level, governmental RES-E targets or target achievement calculations must be adjusted at the same time to achieve full additionality (discussed in Section 3.3).

Deployment additionality means that RES-E must come from assets that would not exist in the absence of RFNBO production. This is the only aspect of additionality mentioned in RED II, specifically in Recital 90: “Furthermore, there should be an element of additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy.” Whether the mentioned element of additionality might require only partial compliance with the concept of additionality would need to be evaluated from a legal perspective. The upcoming RED revision could be an opportunity to clarify the need for deployment additionality.

Surplus electricity could count as additional if it is RES-E that would have been curtailed in the absence of RFNBO production. However, Article 27, or Recital 90, of RED II do not explicitly plan for surplus RES-E to fulfil the requirement of additionality. Stakeholders advocate that counting surplus RES-E as additional should be accepted (Öko-Institut e.V., 2017; Energy Technologies Europe; Cerulogy, 2019; Power to X Alliance, 2020). Surplus electricity might not come from RES-E assets that were deployed additionally, but the electricity would, by definition, not have been fed into the grid (i.e. produced) in the absence of RFNBO production. RES-E volumes that would have been curtailed in the absence of RES-E should count as additional and do not need to fulfil the deployment additionality requirement. RFNBO operators would not be obligated to contribute to RES-E asset deployment—it would be to align their production process to curtailment in the electricity system in which they operate.

Given the economics of RFNBO production and from a risk perspective (the amount of local curtailment might change over time), investment decisions would almost certainly not be driven by the availability of curtailed electricity, except for in specific cases. Rather, surplus electricity could be seen as a possible addition to the business case; if rules were implemented correctly, the surplus could also help the flexibility (e.g. upward demand side management) of the electricity system.

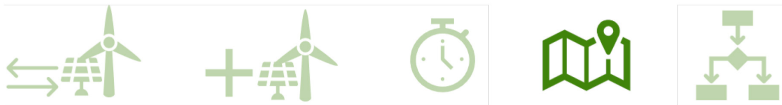
6.1.3 Temporal correlation



Recital 90 of RED II foresees that if grid electricity for RFNBOs is to be counted as renewable, there should be: “temporal […] correlation between the electricity production unit with which the producer has a bilateral renewables PPA and the fuel production.” An example for such correlation is that RFNBOs “cannot be counted as fully renewable if they are produced when the contracted renewable generation unit is not generating electricity.”

The motivation to ensure temporal correlation is twofold. First, if there is a temporal mismatch between RES-E and RFNBO production, the latter may consume non-renewable electricity, undermining the RED II requirement that this electricity needs to be exclusively from renewable sources. Second, RFNBO technologies are meant to be a pillar of fully renewable energy systems. They should facilitate the integration of intermittent RES-E production by being a flexible load oriented to RES-E infeed.

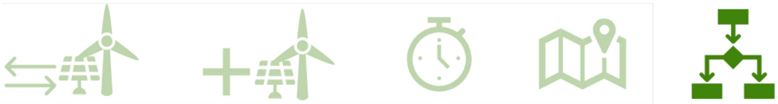
6.1.4 Geographical correlation



Recital 90 of RED II also foresees that if grid electricity for RFNBOs is to be counted as renewable, there should be a “geographical correlation between the electricity production unit with which the producer has a bilateral renewables *PPA* and the fuel production.” An example for this is “electricity grid congestion, where fuels can be counted as fully renewable only when both the electricity generation and the fuel production plants are located on the same side in respect of the congestion.”

There are two reasons for this requirement. First, it would be difficult to argue that RFNBO electricity feedstock is of renewable origin if both assets are far away from each other or separated by a structural grid bottleneck. Second, RFNBO production as a potential major electricity consumer should not contribute to growing congestion issues with asymmetries between load centres and RES-E generation centres.

6.1.5 No double counting



In Article 27.3, RED II stipulates “that the renewable properties of that electricity are claimed only once and only in one end-use sector.” Double claiming the renewable property of the electricity consumed to produce RFNBO could occur at two levels:

- First, Member States could hypothetically double count the renewable property when calculating their overall share of renewable energy by accounting it to the produced renewable electricity and the resulting RFNBO towards the final consumption of renewable fuel in the transport sector.
- Second, double counting could occur at the producer level. Two separate producers, be it RFNBO producers or RES-E generators, could claim and market the renewable property of the electricity. In turn, customers could face a double disclosure of the renewable property—first via the label RFNBO and second via a GO on the consumed electricity. However, this consideration of the commercial electricity market does not represent a risk of double counting towards the renewable energy target, as RED II does not expect GOs to have a role in target accounting.

Double counting leads to adverse effects. It would undermine the idea of RES targets by decreasing the ambition level of the targets by an uncertain amount. In turn, RES deployment would decrease, leading to additional GHG emissions. Moreover, it would depreciate the value of the renewable property as it increases the total amount of available electricity and fuels that can be labelled as green. This could again lead to a decrease in RES deployment.

To avoid double counting:

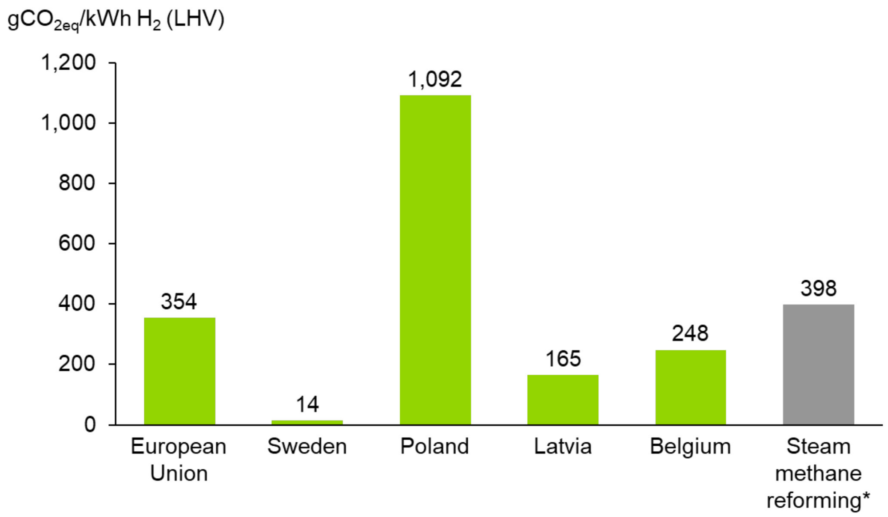
- **Member States** must count RES-E used for RFNBO production only once (i.e. only in one end-use sector).
- To be of 100% renewable origin, the electricity claimed by the **RFNBO producer** must not be claimed by another economic operator.

6.2 Why do additionality, temporal and geographical correlation matter?

This section discusses the rationale for the additionality, temporal and geographical correlation requirements for RFNBO production in more detail. First, RFNBO production without additionality, temporal and geographical correlation (*no criteria)* is discussed. Second, the effect of each of the three criteria is discussed and also their combined impacts. Both the effects on GHG footprint and the economics of RFNBO production are put in perspective.

With *no criteria* present, the GHG emission footprint of RFNBO produced from grid electricity will, generally speaking, be equivalent to the grid emission factor (average, or relative to the time RFNBO has been produced at) times the system electrical efficiency of the RFNBO plant (neglecting the possible additional heat and carbon inputs). As apparent from Figure 9, vast discrepancies in the resulting GHG footprint would occur in different Member States if *no criteria* were put in place. In some Member States, the resulting RFNBO would be no better than steam methane reforming from a climate perspective. Thus, the aforementioned criteria are aiming to significantly decrease the RFNBO GHG footprint when electricity is being sourced directly from the grid.

Figure 9. RFNBO GHG footprint using average grid emission factors[27]



(Source: European Environment Agency)

In this context, it is important to discuss the concept of a marginal power generation plant. Generally, dispatch of various electricity sources is organised so that power plants with the lowest variable production cost are put into operation first. In most markets, the resulting merit order is then renewables, nuclear, coal, natural gas, and oil (storage can somewhat complicate the picture). The marginal plant in this merit order is the source that gets dispatched in case of an additional load. However, different power plants are also limited by their flexibility (i.e., the ability to quickly ramp production up or down). In most electricity markets in the EU, peak demand is met by gas-fired peakers and, to a lesser extent, coal-fired generators (and hydropower where available). One can argue that RFNBO production having to follow *no criteria* will add to the electrical load during peak demand hours, and its demand will be mostly covered by marginal plants or peakers using gas or coal power. This risk is especially driven by economic factors (i.e. producers trying to spread the relative CAPEX cost over more FLH, or RFNBO production support) that might drive RFNBO plants to operate virtually around the clock and not respond to electricity market price signals. In such cases, RFNBO operators would likely not lower their load at times where gas and coal power plants are dispatched as marginal plants.

The situation described in the previous paragraphs (*no criteria)* can significantly change if one or more of the aforementioned criteria are introduced. It is, however, difficult to understand all the possible effects.

First, additionality (without temporal and geographical correlation requirements) is explored. For simplification, let us assume that the additionality criteria results in equivalent contracted,

[27] Assuming 65% system electrical efficiency (LHV). *Steam methane reforming estimations are for process emissions only, excluding effects from upstream and methane leakage. Data are for 2020. European Environment Agency. *Greenhouse gas emission intensity of electricity generation in Europe*. 2021. **https://www.eea.europa.eu/ims/greenhouse-gas-emission-intensity-of-1.**

new (hence additional) RES-E generating capacity to the capacity of the RFNBO plant (e.g. 100 MW_p solar for 100 MW_{el} RFNBO). The additional solar plant now becomes part of the merit order. One could argue that if the megawatt-hours (MWh) produced by the solar plant in a year match the MWh consumed by the RFNBO plant, the resulting RFNBO has a zero GHG emission footprint (excluding embedded emissions). However, that would require that the RFNBO plant is, at any given time, only consuming as much electricity as is the solar plant is producing. If this production and consumption correlation is not maintained, the marginal power generation plants at the time of generation and consumption are relevant for the GHG balance. The first marginal plant (M1) is the one that got displaced by the surplus production of the solar generator (i.e. times when the contracted solar plant production exceeds the RFNBO load). The second marginal plant (M2) is the one that had to be dispatched to meet the RFNBO load at times when the contracted solar production did not fully meet the RFNBO load. In cases where M1 has a lower GHG footprint (e.g. natural gas) than M2 (e.g. lignite), the associated GHG footprint of the RFNBO production would be larger than zero. In theory, also the reverse situation is possible (M1 is lignite and M2 is natural gas) which could result in a positive GHG effect.[28] This shows that the dispatch of the RFNBO plants has an effect on their GHG footprint, which is the motivation for the temporal correlation criterion (see below).

The conclusions above are, however, only valid for a situation with geographical correlation between the RES-E and RFNBO plants. Without geographical correlation, the local RFNBO production footprint would be equivalent to that of the *no criteria* situation described previously. On the other hand, the other local (location of the RES-E plant) grid emission factor could be lowered. However, in a similar way described above for the additionality requirement, a direct comparison is perhaps misleading. Consider a situation where the local RFNBO demand is met by marginal plant coal with a high GHG emission factor. Conversely, the local marginal plant for the RES plant region would be natural gas or hydrogen with a much lower or near-zero GHG emission footprint. In this sense, the MWh of electricity are not equal; their local context and the dispatchability of nearby power plants do play an important role. As with additionality, in theory, also the reverse situation is imaginable.

Finally, the logic of the temporal correlation requirement is discussed. The basic premise of the temporal correlation requirement is to prevent adverse effects of RFNBO production– e.g. dispatch power plants with high GHG emissions, grid congestion, etc. In general, stricter temporal correlation (e.g. hourly matching between production and consumption) minimises the risk that any marginal, high-emitting, power plants need to be dispatched to meet the RFNBO load. On the other hand, it will increase the RFNBO production costs (compared to a situation when only monthly or yearly temporal matching is required). It is worthwhile to explore the two basic ways to assess the temporal correlation requirement – with and without additionality (whilst requiring geographical correlation in both cases).

A standalone temporal correlation requirement on project level (no additionality, with geographical correlation) would effectively mean that electricity is sourced from already existing RES-E plants, more or less following their production profile. With strict temporal correlation (e.g. hourly following), the mismatch between the time of renewable electricity production and consumption can thus be minimised. Yet, the electrolyser load could take away RES-E for direct electrification (e.g. transport, heating). Because of the efficiency losses involved, there might be a net negative effect on the GHG footprint on a system level (i.e. the GHG reduction with direct electrification using renewables is greater than with using

[28] Note that safeguarding additionality is important from today's perspective where many MS's power grids have high GHG emissions. In the coming decades, the relative importance of the additionality criteria will likely decline with the continuous decarbonisation of Member States' power grids.

RFNBO).[29] This speaks for temporal correlation of the RFNBO plant with the RES-E share and GHG footprint on power system level, which would be more effective and efficient in avoiding GHG emissions. This option is elaborated in section 6.4.3.4. With less strict temporal correlation (e.g. monthly, yearly following) and no additionality, the RFNBO production would be roughly equivalent to the *no criteria* situation described above and thus potentially resulting in a high GHG footprint of the produced RFNBO.

Finally, this paragraph explores the effects of temporal correlation on project level combined with additionality (and geographical correlation) requirements. A strict temporal correlation (e.g. hourly following) together with the additionality requirement minimises the risk that any marginal, high-emitting, power plants need to be dispatched to meet the RFNBO load. In theory, the RFNBO plant would then only run simultaneously with the RES-E plants it sources from (and also only run as much as the RES-E plants). This would be challenging and expensive from a RFNBO production perspective. An argument can be made that the electrolyser could be run regardless of these criteria to meet the hydrogen demand and not all of its production would comply with the RFNBO criteria. Here an important trade-off needs to be considered. On the one hand, requiring strict temporal correlation can reduce the likelihood that the RFNBO plant adds load to high emitting marginal plants (consider the M1 and M2 situation described previously). On the other hand, it will come at an increased cost of RFNBO production (and thus need for additional subsidies) and increase the administrative burden of both the administrator and market operators. One could argue that strong additionality and geographical correlation requirements will already decrease the chance of a high GHG footprint of the RFNBO production. As such, less strict correlation, or temporal correlation on power system level (i.e. not only with the contracted RES-E plant, see above) could be considered. Such options are further described in Section 6.4.3.

Modelling the effects of temporal correlation

The effects of temporal correlation on project and system level have been modelled during the preparation of the impact assessment for the hydrogen and decarbonised gas market package. However, the system level correlation referred to GHG intensity and not to RES-E share. Overall system and RFNBO production cost, as well as system and RFNBO GHG intensity, were explored under different modes of temporal correlation. In all of the modelled scenarios RFNBO production had a basis of contracted (PPA) RES-E plant(s) with full additionality, geographical correlation (same country) and hourly temporal correlation. On top of the directly contracted RES-E, the RFNBO operators could source from the grid without the need for direct contracting (PPA):[30]

- Option #4a: Sourcing from the grid is only allowed in hours where the average grid emission factor is equivalent to or below 60 gCO_2/kWh (derived from Taxonomy threshold).
- Option #4b: Unlimited sourcing from the grid based on electricity market prices.
- Option #3 (sensitivity): Sourcing is allowed only from contracted (PPA) plants, with no additional grid sourcing (except to meet minimum load).

[29] This effect is partly dependent on the end-use applications. For instance, using RFNBO to displace current hydrogen production (e.g. steam methane reforming) will result into much higher GHG emission reductions compared to using RFNBO in fuel cell vehicles. To fully understand these effects and allow for comparison, one would have to understand which end use applications the renewable electricity and RFNBO were supplied to.

[30] Note that the criteria used for grid sourcing in the Impact Assessment (threshold based on GHG intensity of the grid) is different from the criteria explored in this study (threshold based on RES-E share on total generation). Regardless, the general conclusions are likely to be comparable, regardless of the threshold selected.

In most of the modelled scenarios, an international hydrogen transmission network and storage are in place, allowing for cross-border trade. This brings an additional level of complexity to the understanding of RFNBO production under various circumstances. Nevertheless, in all three of the main modelled scenarios, the average hydrogen GHG content increased significantly between Option #4a (with GHG rules on grid sourcing) and Option #4b (without such rules):

Table 2. Hydrogen CO_2 content for different temporal correlation modes

Modelling scenario	Hydrogen CO_2 content ($gCO_2/kWhH_2$; LHV)		
	Option #4a (sourcing when grid <60 gCO_2/kWh)	Option #4b (unlimited sourcing from grid)	Option #3 (PPA sourcing only)
H2-BAU	20	50	N/A
H2-A constrained	15	35	N/A
H2-A optimised	10	20	6

Source: Artelys

Still, it is important to compare these results to the GHG footprints presented in Figure 9. The highest footprint modelled (50 $gCO_2/kWhH_2$) is 7 times lower than RFNBO produced from using the average EU grid emission factor.

In terms of the cost of RFNBO production, the study estimates a marginal cost increase (less than 0.2 EUR/kgH_2) in Option #4b, compared to Option #4a.[31] There is, however, a non-marginal increase in total system costs in Option #4b (around 1 billion EUR/year), as expensive gas power generation gets dispatched more often. Option #3 (PPA-only) results in a significant increase in RNFBO costs (by approximately 1.2 EUR/kgH_2). The overall system cost is, however, lower, in the PPA-only Option #3, (approximately 1.8 billion EUR/year).[32] **In summary, fewer constraints on the time of RFNBO production decrease production cost, increase the GHG footprint of the produced RFNBO and increase overall system costs.**

Importantly, these trends would likely be amplified in case of the absence of the temporal correlation requirement (hourly) between the contracted (PPA) RES plant and the RFNBO plant.[33] However, while these results are important, they have to be interpreted carefully. There are many other interdependencies at play, influencing the results (production

[31] The cost in this section means delivered cost, including hydrogen production, transmission, and storage. All quantitative results for this part were based on: Artelys, *METIS study on costs and benefits of a pan-European hydrogen infrastructure* (not yet published). Guidehouse has access to these results as part of the study for the European Commission: Guidehouse & Frontier Economics, *Assistance to the impact assessment for designing a regulatory framework for hydrogen* (not yet published).

[32] These cost savings are mostly driven by avoided (additional) investments into natural gas turbines and fuel (gas) costs. These savings a significantly higher than the additional investments into RES-E capacities and hydrogen infrastructure (pipelines, storage). The additional investments are necessary as the production of RFNBO is more restricted and thus supply and demand are harder to balance.

[33] A quantification of the effect of different temporal correlation requirements has, for instance, been performed in Frontier Economics. The study shows 0.7 EUR/kgH_2 production cost decrease (20%) between daily and yearly temporal correlation requirement (regardless of how the additionality requirement is implemented). Frontier Economics. *RED II GREEN POWER CRITERIA - IMPACT ON COSTS AND AVAILABILITY OF GREEN HYDROGEN IN GERMANY*. 2021. **https://www.efuel-alliance.eu/fileadmin/Downloads/red-ii-green-analysis.pdf**.

relocation, different RES generation profiles in different countries, hydrogen infrastructure over- and under-capacities, etc.).

6.3 Fulfilment vehicles

Economic operators and public authorities will need to use platforms or protocols to exchange evidence on the fulfilment of the requirements presented in Section 6.1. These fulfilment vehicles include RES-E GOs, PPAs, project-level assessments (PLAs), or RES-E deployment funds. For each of these vehicles, a variety of modifications exist or have been explored in literature. Sections 6.2.1 through 6.2.4 provide a basic summary of the possibilities.

6.3.1 Guarantees of origin

In 2001, the Commission, through the EU Directive 2001/77/EC, introduced the concept of GOs to enable RES-E tracking. Through this Directive, the Commission mandated that all Member States develop a GO tracking system that allows power generators, retailers, and consumers to trace and have evidence of the type of renewable electricity they were buying and selling. The typology includes the origin of the power (location), the technology used, power plant age and size, and whether the generator has received government support or not.

The primary objectives of the GO system are to disclose the energy origin of electricity sold to customers and to facilitate the promotion of renewable energy sources and, in some Member States, high efficiency cogeneration. GOs therefore serve the purpose of informing consumers. They do not have a role in determining contributions towards renewable energy targets.

In 2009, the Commission updated the 2001 Directive to the EU Directive 2009/28/EC, through which it established a common framework to promote renewable energy sourcing. This Directive defines GOs as “an electronic document which has the sole function of providing proof to a final customer that a given share or quantity of energy was produced from renewable sources.” In principle, the concept of GOs established in 2001 continued to exist; however, the 2009 Directive underlined that the GO system differs from government support schemes, such as feed-in-tariffs (FITs), or statistical RES transfers, in that GOs are basically a document that proves that the electricity is produced from renewable energy sources.

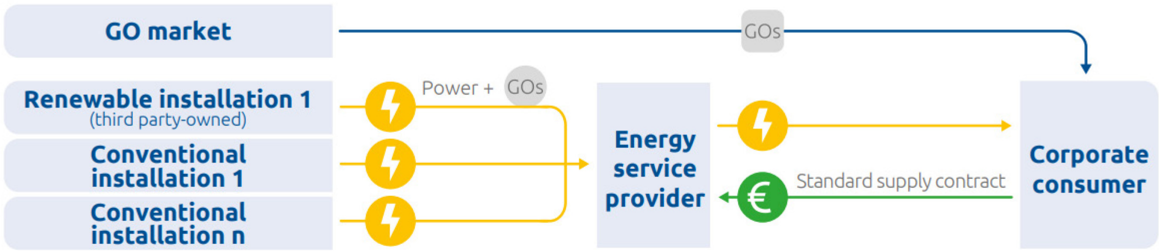
Trading GOs is voluntary between generators, suppliers, and electricity end users (i.e. commercial and industrial customers). Electricity suppliers and end users decide to take part in this trading if they want to claim they supply or consume RES-E. Importantly, GOs track information about location, date of issue, and whether any public subsidy has been given to the facility that has produced the GO, which is relevant to the analysis of the fulfilment options in Section 6.3.

A transparent and credible attribute mechanism, such as a GO, can guarantee that a specific amount of energy originates from a certain source. Under RED II, Member States must recognise GOs issued by other Member States in accordance with RED II. The detailed aspects of GOs are presented as follows.

6.3.1.1 Unbundled GOs

The process starts at the electricity generator, which has the right to ask the national issuing body to issue GOs equivalent to the RES-E generated. Each country where GOs are traded has a national registry that keeps track of all transactions. While cross-border GO trading is possible in most Member States, there is still a need for aligning these national registries. Currently, the AIB counts 28 members, including Norway, Iceland, and Switzerland. Once the electricity generator holds the GOs, they can sell them to electricity suppliers or end users through traders or brokers. GOs are sold separately from the electricity itself (i.e. unbundled GOs), but the market is trending towards bundled GOs, mainly due to perceived higher credibility.

Figure 10. Sourcing model for unbundled GO certificates



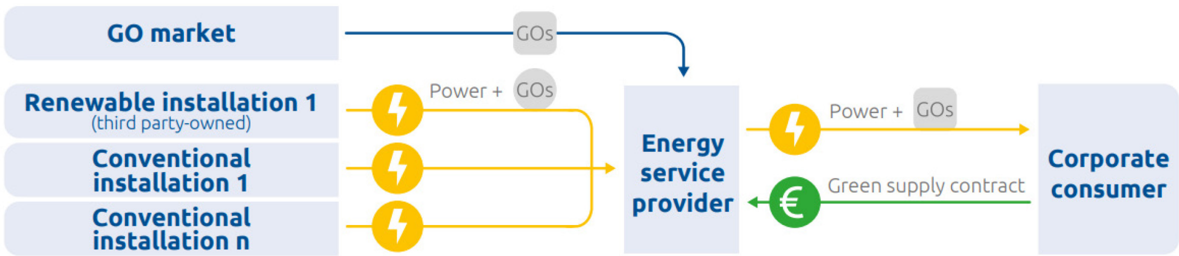
Source: RE-SOURCE, 2020

In general, the GO system set-up by the Commission seeks to avoid double counting RES-E claims towards end consumers (i.e. a GO should be claimed by only one entity). For example, if a supplier wants to disclose the share of RES-E they are providing to their customers, the supplier must cancel the GOs in the national registry. Overall, the registry verifies the claims and tracks the issuing and cancelling of GOs, avoiding having suppliers that sell RES-E to end consumers multiple times.

6.3.1.2 Bundled GOs

To harmonise GO tracking across Member States, the European Electricity Certificate System (EECS) was created. The EECS provides a common system for national issuing bodies and registries to track all transactions and enables the transfer of GOs across Member States. To fulfil its role, the EECS offers a communication hub run by the AIB, where national issuing bodies and registries cancel and transfer GOs. National issuing bodies and registries exist in 23 European countries.

Figure 11. Sourcing model for green power products (bundled GO certificates)



Source: RE-SOURCE, 2020

Reportedly, there is a significant oversupply of conventional GOs on the European market, with GO prices below 0.3 EUR/MWh, which corresponds to 1% or less of the typical wholesale electricity prices. This oversupply is expected to continue for an extended period, as most subsidised RES-E facilities in the EU are awarded GOs while the demand for certified renewable electricity is relatively much lower (Öko-Institut, 2017), (Cerulogy, 2019). Under such a system, additionality in terms of the transport sector (or RFNBO producers, specifically) contributing to RES-E financing in a meaningful manner is unlikely. An alternative GO system is discussed in Section 6.3.1.3.

While GOs are the EU certification system, its equivalents are present in countries with national renewable energy certificate (REC) systems (including Australia, China, India, Mexico, and the US) and in countries without national systems, where international RECs (I-RECs) are available. The list of approved I-REC countries is growing rapidly, mainly because industrial consumers are seeking green power supply to meet global sustainability targets. The list currently includes China, India, Russia, Brazil, Egypt, and Morocco and excludes Mongolia, Bolivia, and Sudan. The I-REC standard allows existing installations to apply for registration and is not exclusively for newly built RES-E projects.

6.3.1.3 GOplus concept proposal

The GOplus scheme proposed by Öko-Institut is a variation of the GO system (Öko-Institut, 2017). Under this scheme, certificates would only be awarded to new RES-E projects that have not or do not receive financial support from public schemes. Article 19 of RED II includes the option “not to issue such a [GO] to a producer that receives financial support from a support scheme,” meaning that electricity produced from subsidised assets would no longer be awarded GOs. The project developer may then choose between the financial incentive of receiving subsidies and the incentive of selling GOs on the market. In some Member States (e.g. Germany and France) subsidised RES-E projects do not receive GOs as an additional incentive. Instead, GOs under the national subsidy scheme are transferred to the utility or cancelled, taking off the electricity of that RES-E unit and increasing the share of renewables for all consumers of (grey) electricity that are refinancing the subsidy scheme through a levy. In contrast, in other Member States (e.g. Belgium and the Netherlands), GOs are issued for subsidised RES-E projects. To achieve strong additionality, the GOplus concept recommends removing the additional RES-E generation stimulated by final consumers of electricity from the renewable energy volumes counted towards national or EU-wide targets (Öko-Institut, 2017).

The concept also envisages that competent bodies would be appointed to adjudicate GOplus certificates awards for “surplus production that would have been otherwise curtailed” (Cerulogy, 2019). In that sense, GOplus could be used both for regular and surplus electricity sourcing, recognising that surplus electricity is more complicated (as discussed in Section 6.4.2).

6.3.2 Power purchase agreements

In most Member States, off-takers can contract directly with a specific third party-owned generator to obtain RES-E through PPAs. PPAs are long-term contracts (often 10-20 years but sometimes longer or shorter durations) between the organisation purchasing RES-E and a party that generates the electricity.

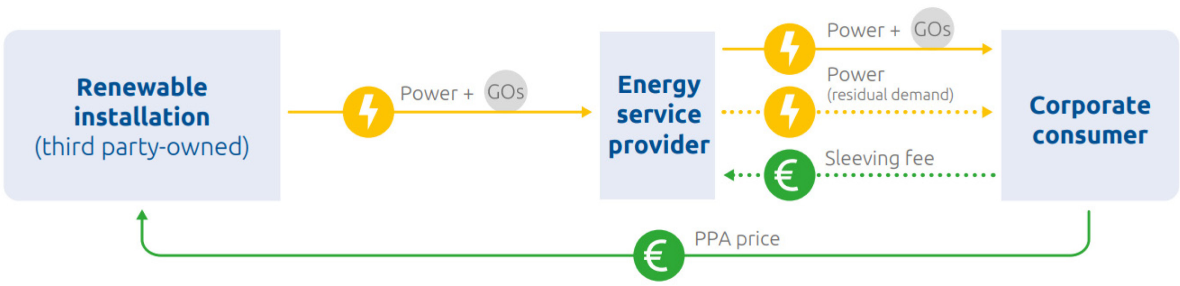
Direct purchase options include physical PPAs and financial PPAs. Both arrangements offer consumers a tangible and clear association with a specific renewable energy facility. PPAs (usually corporate) typically include the transfer of GOs as it is illustrated in the Figures 12 and 13. There is, however, no obligation to sell or procure GOs in the context of a PPA. A

PPA may solely arrange the transfer of the commodity (electricity) and exclude any provisions for its attribute (GO). In that case, the RES-E producers could sell their GOs separately to the GO market, even though these sales could be considered problematic for consumer market transparency.

6.3.2.1 Physical PPAs

In physical PPA engagements, the RES-E generator can be onsite or offsite, but the buyer is typically located on the same power grid to allow for physical electricity delivery. Cross-border physical PPAs are rare as they require appropriate interconnector capacity bookings. The contract specifies the electricity price (generally a long-term rate with a price escalation clause), the schedule for electricity delivery, and the transfer of GOs from the generator (seller) to the purchaser. The purchaser must ensure the GOs are included in the PPA for the electricity to be considered renewable and to substantiate RES-E use and environmental claims. The benefit of PPAs is they require no or little capital investment on the part of the purchasing organisation, offer electricity cost certainty, and allow for savings accrual, often within the first year.

Figure 12. Sourcing model for physical PPAs



Source: RE-SOURCE

PPAs may present various risks to both parties. For instance, the purchaser may bet that future market RES-E prices will be higher than the negotiated PPA price. If electricity prices go lower than expected, the purchaser will forego savings. A price surge on the wholesale market may result in an economic disadvantage for the supplier that is bound to the agreed PPA price. The underlying assumptions that go into determining the PPA price are often key to whether it will offer savings to either party. The seller and the buyer may agree on a floating price that is linked to the wholesale market, but that option is limited to a band with a price floor and a price cap to mitigate price risks.

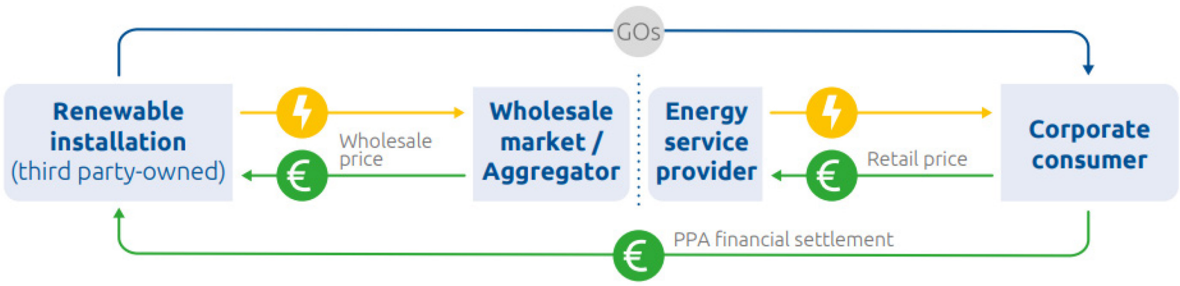
6.3.2.2 Financial (virtual) PPAs

A financial PPA, also known as a virtual PPA because the energy is not delivered to the buyer, is a long-term contract in which a generator and purchaser agree on a reference electricity settlement price (the strike price, which may include an escalator rate). The electricity generated by the project is sold into a wholesale regional power market where the generator is located rather than delivered to the buyer; therefore, the buyer’s electricity consumption can occur in a different power market than where the RES-E generator is located, including in a traditionally regulated retail electricity market.

In a financial PPA, any difference between the settlement price and the wholesale market price is balanced by both transacting parties over the life of the contract. On a monthly basis, if the generator earns more from the wholesale market than the strike price, it pays the extra revenue to the purchaser; if the generator earns less than the strike price, the purchaser makes up the difference to the generator. This option is also referred to as a contract for differences.

The financial PPA is a hedge for both parties, ensuring fixed revenue to the seller and fixed costs to the buyer. As a RES-E purchase option, a financial PPA must convey GOs to the buyer. As with a physical PPA, the a financial PPA does not protect the parties against the risk of fluctuating electricity prices—it just provides certainty. Seller and the buyer may agree on a floating price linked to the wholesale market, but these agreements are limited to a band with a price floor and a price cap.

Figure 13. Sourcing model for financial PPAs



Source: RE-SOURCE

6.3.3 Private or public RES-E deployment funds

An emerging alternative to RES-E procurement through traditional bilateral PPAs could be contributing to a fund that deploys RES-E assets. The RFNBO producer would pay into a fund that uses the collected capital from all contributors to tender new RES-E capacities outside existing RES-E support schemes (see Figure 13). In turn, the RFNBO producer would be (partly or fully) supplied with the RES-E produced from these capacities and the corresponding renewable credits (e.g. through GOs). While pooling funds might present an attractive option to streamline RES-E procurement in future, important questions would be to be addressed first—notably, how the assets would be deployed by the fund to comply with the requirements (e.g. temporal and geographical correlation) or the level of payment from RFNBOs to comply with the additionality requirement. Verification and oversight of such a fund would need to be determined.

This vehicle combines some of the features of GOs and PPAs. As with PPAs, specific RES-E assets are contracted over a longer period, securing the price is and coupling it with levelised cost of electricity (LCOE) rather than volatile market values. As with GOs, the RFNBO producer simply pays a price per unit of energy to the fund and does not need to originate RES-E assets and close contracts with them.

The fund's function is to pool the contributions from RES-E consumers and to procure corresponding RES-E volumes. In principle, this can be performed by public and private entities:

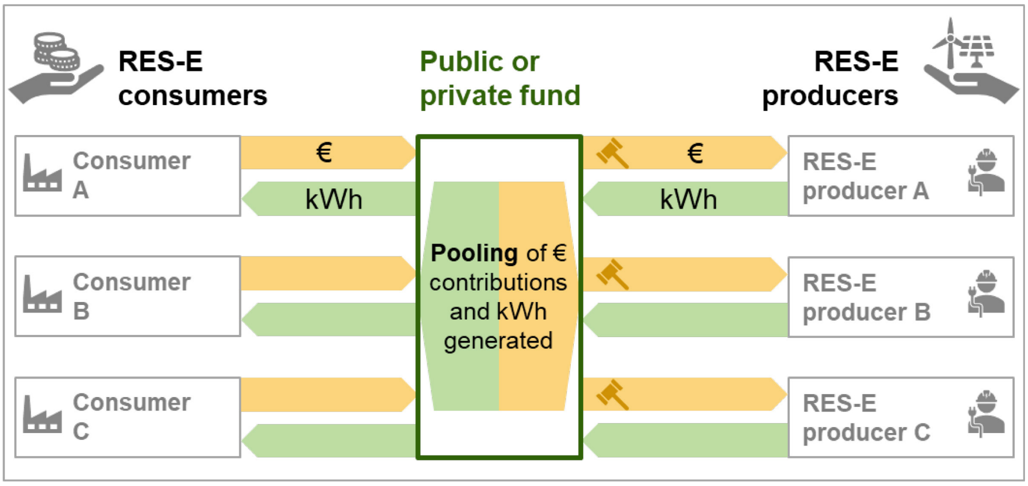
- **Public:** Article 33 of the Governance Regulation[34] obliges the Commission to establish a Union renewable energy financing mechanism by 1 January 2021. The purpose of the mechanism would be to "tender support for new renewable energy projects in the Union" based on financial contributions from Member

[34] REGULATION (EU) 2018/1999

States and the private sector. This mechanism would be a conceivable vehicle for RFNBO RES-E sourcing, but similar national funds may also be an option.

- **Private:** The example of a private fund is the GO^2 scheme run by ECOHZ. ECOHZ offers two options:
  - GO^2 United, where contributions from many stakeholders are pooled together (premium as of July 2020 is 0.6 EUR/MWh)
  - GO^2 Signature, where a sole-sourced unique RES-E project is financed (premium as of July 2020 is 3.2 EUR/MWh) (ECOHZ, 2020).

With both options, only new RES-E assets can be financed; however, the GO^2 scheme does not necessarily prevent new assets from receiving additional financing, including public financing.



Source: Guidehouse

These pooling funds could add to RES-E deployment while providing rather minimal administrative burden for RFNBO operators (assuming the premiums paid to the fund are adequate to cover any price gaps). The RES-E deployment facilitated by such funds would likely only happen with a time delay relative to the RFNBO production (temporal requirement) and if international (even if EU level) funds could not guarantee the RES-E generation and consumption have geographical correlation (geographical requirement).

6.3.4 Project-level assessments

With a PLA, RFNBO production sites are evaluated on a case-by-case basis on whether they fulfil the requirements for renewability under RED II instead of using vehicles available through the electricity markets (such as PPAs and GOs). The Clean Development Mechanism (CDM), established under the Kyoto Protocol, is a prime example of a PLA. With the establishment of Article 6.4 of the Paris Agreement, the CDM will end as a mechanism of the Kyoto Protocol; however, as noted by researchers, its standards, procedures, and institutional agreements could form an important basis for any crediting mechanism (Öko-Institut, 2016).

The CDM was developed to demonstrate that new renewable energy projects in the developing world would not have been installed without the support of the CDM (Cerulogy, 2019). The CDM examines additionality by using positive lists and PLAs. Such concepts could be adapted for the purposes of the DA via automatic additionality for RES-E projects below a certain size (i.e. positive lists)[35] and ex ante PLAs using parts of the CDM methodology. Using the current CDM methodology would require significant review, and possibly significant updating, to match the needs of the DA discussed in this report.

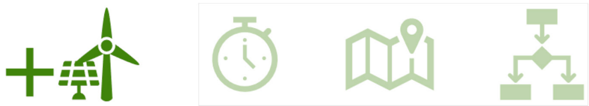
PLAs or the CDM could be used in the context of RFNBO production. The main advantage of such an approach is its international applicability; the adapted standards and procedures could be used to develop a unified international system in light of the RED II requirements for RFNBO production. However, notable issues with this approach including the following:

While RED II presumes a dynamic matching between the RES-E producers and RFNBO operators (e.g. temporal and geographical requirements), PLAs only consider ex ante evaluation, which is more suitable for a static matching between volumes of RES-E produced and consumed.

Most RES-E generation projects registered under the CDM were evaluated as non-additional by a subsequent analysis (Öko-Institut, 2016). This evaluation implies that a substantial revision (including determining price gaps in respective countries, for instance) of the CDM would be required. An analysis of the CDM remarked that formally registering a project under the CDM is an expensive and time-consuming process (Öko-Institut, 2016).

One specific case where PLAs could prove highly useful is in determining whether an additionality case can be made for old, previously subsidised assets coming off public support schemes—if these assets were to strike a procurement contract with RFNBO operators. This specific case is discussed in Section 6.4.1.

6.4 Options to meet the requirements in RED II



Deployment additionality means that RES-E must come from renewable energy assets that would not exist in the absence of RFNBO production. This is the only aspect of additionality mentioned in the RED II, specifically in Recital 90: “Furthermore, there should be an element of additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy.” Deployment additionality is important as a safeguard against RFNBO production cannibalising on direct electrification and decarbonisation (relative and percentage wise) of the electric grid. Whether the mentioned element of additionality might require only partial compliance would need to be evaluated from a legal perspective.

The first phase of the project investigated various options in which deployment additionality could be fulfilled (see Appendix 10.3.2). It has been concluded that either sourcing from new, previously unsubsidised RES-E assets or sourcing from old, previously subsidised RES-E assets under specific conditions should be investigated further. Importantly, the project team expects that both direct contractual relationships between the RFNBO facility and RES-E

[35] For instance, the most widely used tool, ACM0002 “Grid-connected electricity generation from renewable sources” (version 16.0), considers technology on the positive list if it contributes less than 2% of the total grid connected capacity or less than 50 MW of the total capacity in the country.

asset or assets (i.e. a PPA) and no direct contractual relationships between them (e.g. GOs) are, in principle, admissible if the additionality principle is fulfilled. The analysis for each is undertaken in the following sections.

All options rely on the premise that the assets apply renewable energy technologies. Article 27 requires the electricity to stem exclusively from renewable sources. All fulfilment vehicles described in Section 6.2 potentially meet these requirements. Article 2.1 defines renewable, non-fossil sources as wind, solar, geothermal, ambient, tide, wave, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas, excluding fossil fuel-based (high efficiency) combined heat and power (CHP). It also states that pumped storage hydroelectricity "should not be considered to be renewable electricity."

6.4.1.1 RES-E from new, unsubsidised assets

If there is no true price parity between wholesale electricity and RES-E prices, any new and unsubsidised RES-E project would rely on additional income streams from their off-takers to be implemented. Therefore, a strong deployment additionality could be achieved if RFNBO operators are only allowed to source electricity from new, previously unsubsidised assets (Cerulogy, 2019; Global Alliance Powerfuels, 2020; Öko-Institut e.V., 2017; Ørsted, 2020).[36]

How could it be implemented?

Compliance could be readily achieved by the use of PPAs, GOs, or various combinations of the two. Other vehicles (e.g. pooling mechanisms or the creation of a separate renewable electricity market) are currently not available and would have to be developed.[37] In essence, to main possibilities exist:

- **Direct contractual relationship via PPAs.**[38] Direct contractual arrangements for renewable power sourcing between RES-E and RNFBO operators present the first option. The advantage of PPAs with eligible RES-E assets is that any price gaps between RES-E LCOE and market prices would be covered by RFNBO producers. Additionally, long-term PPAs facilitate the financing of renewables and increase the bankability of renewables' projects (comparably GOs have no, or much weaker direct link to these aspects, unless they are part of a long-term contract). GOs could be used (surrendered) as a proof of transfer of renewable power. In case the use of GOs is not desirable, a different mechanism would have to be used for this purpose.
- **No direct contractual relationship using GOs:** Aside from PPAs, a broader market of eligible (additional) RES-E assets for power sourcing could be opened by using GOs. Requiring deployment additionality would create a market for a subset of the total available GOs. This subset creation would likely trigger market competition, raising the price of this GO subset (especially when considering further temporal and

[36] Some Member States have argued that RES-E should be sourced from "recent installations that would otherwise not have been built" without specifying whether these installations could be subsidised or not (AT, DK, ES, IE, LU, PT, 2020).

[37] In principle, the EU's renewables financing mechanism (see Section 6.2.3) might be a vehicle to fulfil the option of RES-E sourcing from new, renewable assets. The mechanism will deploy new assets based on the monetary contributions it receives without funding from national support schemes. Many unanswered questions about the specific design of the mechanism remain, so its functioning under this DA is not evaluated further. The latest document on the development of the mechanism can be accessed through the Publications Office of the European Union. "Assistance in view of the setting up and implementation of the Union renewable energy financing mechanism." October 16, 2020. **https://op.europa.eu/en/publication-detail/-/publication/01aabfc5-14dc-11eb-b57e-01aa75ed71a1/language-en/format-PDF/source-170757152**.

[38] Recital 90 of RED II talks specifically about this option: "…That methodology should ensure that there is a temporal and geographical correlation between the electricity production unit with which the producer has a bilateral renewables power purchase agreement and the fuel production.…"

geographical correlation requirements). In such a way, RFNBOs would indirectly add to renewables financing by creating a market demand for new, unsubsidised renewable generation. In sum, such an option would provide a relatively strong element of additionality as well, even though it would provide less investment certainty to RES-E producers.

Determining the new and unsubsidised requirements is of particular importance for deployment additionality. Newness should be defined for the whole RES-E asset relative to the RFNBO facility. The project team proposes that commissioning dates for both the RES-E asset and RFNBO facility be used for this purpose. Commissioning date refers to a facility being technically ready to operate, whereas commercial operations date refers to when the facility starts to generate (electricity or other product) to earn revenue. Both dates can be moved by the operators; however, commissioning dates are typically firmer.

New status: The real definition of new status could be the same as in Case 2 direct connection (Section 5)—i.e. RES-E assets must be commissioned in the same quarter-year as the RFNBO asset or later. However, under RED II, Case 3 does not have as strict prescriptions as Case 2 when it comes to the commissioning date. Therefore, Case 3's definition of new could be broadened to RES-E assets that have been deployed 2 years or less before the commissioning of the RFNBO asset.[39] This definition would provide more flexibility to RFNBO producers and allow RES-E production for the electricity market should there be delays in the RFNBO plant's construction while still safeguarding new RES-E assets. Information regarding the operation commencement of the RES-E asset is required to be registered with the national GO-issuing body so it is readily available if GOs are used. As for standalone PPAs (without the use of GOs), RES-E operators would have to prove operation commencement unless the information is readily available in national Chamber of Commerce registers.

Unsubsidised status: To determine unsubsidised status, RES-E assets must provide information about received subsidises to national GO registers, if GOs are used. The registers will contain information about past-received CAPEX subsidies (e.g. grants) and OPEX subsidies (e.g. feed-in tariffs). At the time a GO is issued, all currently received subsidies are visible in the registry and can be validated. As for standalone PPAs (without the use of GOs), RES-E operators would have to prove their unsubsidised status, and their status would be subject to ongoing verification process (e.g. by requiring sworn statements).

RFNBO-side perspective: From the RFNBO producer's perspective the compliance via any of the options described above would be relatively straightforward while standalone PPAs might prove to be slightly more burdensome due to the additional checks required. As for GOs, RFNBO producers would procure the relevant subset of GOs through existing GO traders or directly from RES-E assets (i.e. with or without PPAs being in place). All the required information is readily available from national GO registries. Alternatively, Chamber of Commerce registers or additional proof (e.g. sworn statements) would be required (standalone PPAs).

Monitoring: An audit on the commissioning date for the RFNBO facility and a regular audit (e.g. yearly and possibly largely automated) to prove that the RES-E asset has not been subsidised during the time period would be prudent. Cancelling GOs would follow the

[39] As outlined in Section 5.2.1, repowering wind turbines should be treated like the installation of completely new assets. In contrast, a lifetime extension of existing RES-E assets through exchanging or upgrading some of the components while the overall external layout of the facility remains unchanged (Wind Europe, 2016) should not be considered new and may only be eligible to count as additional under special circumstances (described in Section 6.3.1.2).

standardised, implemented procedures. The existing GO-issuing bodies could be used to guarantee compliance.

What are risks and challenges?

The requirement to source RES-E from new, unsubsidised assets would ensure strong additionality from the RED II perspective. The most impactful difference on the side of the RFNBO operators is whether direct contractual relationship (e.g. via a PPA) is required, or whether sourcing from other eligible assets without direction contractual relationship is also allowed. This, and several other considerations, are summarised as follows:

1. One of the concerns is that RFNBO operators would have to wait for the RES-E assets to become operational, as some of these assets have long lead times in case of PPAs (e.g. wind energy). This concern could be partly alleviated by purchasing GOs from other eligible assets (if available) in the intermediate period before the anticipated (contracted) asset comes into operation, a condition that is not unreasonable. If sourcing from the subset of eligible RES-E assets (without direct contractual relationship) is not allowed, RFNBO market development might effectively be delayed.[40]
2. RFNBO plants could have a long lead time in respect to particular (contracted) RES-E assets (e.g. PV plants), resulting in possible issues with the newness requirement. The project team recommends addressing this concern by not requiring extremely strict interpretations of newness; a difference of no more than 2 years should be enough to fulfil newness requirements and prevent situations in which particular assets become ineligible for sourcing.
3. A potentially major risk comes from the unavailability of new, previously unsubsidised RES-E assets in sufficient volumes during the first years of the RED II implementation. This possible unavailability could significantly slow the development of the RFNBO market, particularly in certain geographies. This slow development could—and, in the project team's opinion, should—be addressed by increasing requirements over time. The project team elaborates on this option in Section 7. If such concept is deemed not feasible from a legal perspective, alternatives, such as partial compliance exemptions, should be considered.
4. Most importantly, if the pool of possibly eligible RES-E assets is significantly restricted (e.g. by requiring direct contractual relationship via PPAs), the risks outlined above are likely to be significantly aggravated in the first years of RED II implementation. Achieving RFNBO facility load factors that achieve profitability will become less feasible (as the cost of hydrogen production will increase due to lower utilisation of the asset), possibly triggering need for additional supply and demand side subsidies. As the market matures, this risk is significantly reduced. This conclusion also applies to the points mentioned previously.

For GOs as proof of compliance, one related risk is the current standards to record subsidies in national GO registers. Past subsidies (e.g. investment aid or no longer applicable FITs) are not required to be, but might be, deleted from the registry. By requiring assets to be no more than 2 years older than the RFNBO plant and having an unsubsidised status at the time of issuing the GO, investment aid is the only item that might not be captured by this definition. Investment aid is usually not the main RES support scheme. However, several

[40] A precondition to this conclusion is that there would be an available pool of GOs from eligible assets (GO+) in the intermediary period. If that was the case, there would likely be scarcity of these eligible RES-E assets (demand > supply). Alternatively, if the "increasing requirements over time" are implemented (Chapter 7), simple GOs could initially be used for part of the RFNBO production.

Member States are using CAPEX and investment support instruments to support RES-E production. A remedy to this risk would be requiring that information about subsidies remain in the registry for the entire lifetime of the RES-E asset, yet this is not the common practice across all Member States.[41]

6.4.1.2 RES-E from old, formerly subsidised assets

This implementation option would mean also allowing sourcing from any RES-E asset of any age, depreciated or not, that has been (but no longer is) supported by public money in development or operation. In general, such RES-E assets would not fulfil the additionality requirement of RED II. However, with many existing RES-E assets already or soon to be at the end of their support period, a case could be made for their eligibility in specific circumstances. Such assets could claim that continuous operation is no longer viable in the absence of subsidy payments and that a direct contract (e.g. via a PPA) could prevent them from ceasing operation (VDMA, 2020). The economic nonviability of continuing operation could be caused by situations when replacement expenditures,[42] OPEX, and target margins would create a net negative cash flow when assuming the expected wholesale market prices for RES-E. An additionality claim could be made for RES-E assets that would demonstrably plan to cease operations and where a PPA with an RFNBO producer would prevent them from doing so. In general, continuing operation of such RES-E assets (i.e. where economic viability of operation is shorter than technical lifetime) is desirable.[43]

How could it be implemented?

A direct contractual relationship (e.g. a PPA) made between the RES-E asset and RFNBO facility should be required (GOs could still be used as a proof of the transferred electricity). Standalone GOs (i.e. without a corresponding PPA) should not be allowed as they cannot be seen as proof of additionality in these circumstances.

To demonstrate that a contract with an RFNBO producer would be a crucial factor in prolonging the economic lifetime of the RES-E asset, such a claim would need to be developed on a case-by-case basis (for instance, via a PLA). This claim could show net negative cash flows from average wholesale market prices for the market in which the RES-E asset is located (for instance, in the last 2 years) and net positive cash flows from the PPA with the RFNBO producer. The general methodology for such financial analyses should follow existing standards set by the Commission, such as cost-benefit analysis (CBA) guidelines (European Commission, 2014). Standardised OPEX and replacement expenditure[44] ranges could be developed by the Commission to be used as eligible inputs for such calculations. Table 2 provides an illustrative example. The standard OPEX outlined is rather high for illustrative purposes. Based on the project team's analysis of IRENA data, O&M costs range for European onshore wind assets between 7.7 EUR/MWh (Denmark) and

[41] Guidehouse bases this information on conversations with the Dutch national registry (CertiQ) and German Umweltbundesamt.

[42] Excluding repowering situations, which would be treated as new after repowering (see Section 6.3.1.1).

[43] Wind Europe estimates that owners of 38 GW of installed wind capacity will have to make a decision about their future in the next 5 years. 29 GW should likely continue operation with lifetime extension, 2.4 GW would be repowered, and 7 GW would be fully decommissioned according to their estimates (Wind Europe, 2021).

[44] Shown as CAPEXin the following. Non-significant lifetime extensions (economic or technical), such as lifetime extensions, would be eligible as CAPEX (or REPEX) expenditures in the proposed assessment. In this way, the operational lifetime is extended beyond the design lifetime by having small components exchanged or refurbished (for instance, in wind energy the gearbox can be sent for refurbishment instead of buying a new one) or by curtailing to reduce fatigue loads. Significant extensions or alternations defined as repowering would reclassify the whole asset as new (thus potentially eligible under the previous sourcing option as "new, previously unsubsidized assets").

17.5 EUR/MWh (Germany).[45] However, these costs might be somewhat higher for older assets. For comparison, the average intraday spot market price was 37 EUR/MWh in Germany (2019) and 53 EUR/MWh for day-ahead in Ireland (2019).[46]

An audit would be required at the commissioning date of the RFNBO facility with a PPA in place and an approved PLA. A regular (e.g. yearly and possibly largely automated) audit to prove the PPA is still in place would be prudent.[47] As GOs could be still transferred and cancelled with this option, the already existing GO-issuing bodies could be used to guarantee compliance.

Table 3. Example calculation for PLA proving positive net contribution of a PPA with an RFNBO operator

Parameter	Unit	Value
Initial CAPEX (e.g. lifetime extension)	EUR/MW	200,000
Standard OPEX	EUR/MWh	28
Average load factor over asset lifetime	FLH/year	3,000
Time horizon	Years	10
Discount rate (including margin)	%	5%
Average electricity market price (last 2 years)	EUR/MWh	27
Average price in PPA offered by RFNBO	EUR/MWh	35
Net present value via market price	**EUR/MW**	**(36,041 EUR)**
Net present value via PPA with RFNBO	**EUR/MW**	**140,455 EUR**

Source: Guidhouse

What are risks and challenges?

In principle, this option does fulfil the additionality requirement because the RES-E assets would cease operation in the absence of RFNBO demand. In practice, the project team expects that most RES-E assets falling out of a subsidy scheme would be able to remain operational purely on free market revenues because the operational negative cash flows of RES-E plants are typically small (well below the illustrative example shown in Table 2).[48] The risk is that some RES-E assets that would have remained operational even in the absence of a PPA with RFNBO producers are counted as additional due to a lenient PLA. This is further aggravated by operators that could tune their PLA inputs to become eligible.

Additionally, there is some risk of substandard management of some of the RES-E assets, particularly in cases where full repowering is delayed in favour of lifetime extension in order to qualify for RFNBO production (as old, previously subsidised). However, the project team considers this risk to be relatively small since repowering (and thus improving production costs) would also make the RES-E asset eligible for RFNBO sourcing as well (as new, unsubsidised). Given the sensitivity of RFNBO production to electricity prices, the project team expects the market to deliver cost-efficient solutions.

[45] Analysis based on data for onshore wind in Sweden, Denmark, and Germany (IRENA, 2020).
[46] Using a simple average, based on Guidehouse analysis.
[47] A certification entity would be in charge of auditing all RED II compliance, such as GOs in place, PPAs, PLAs, location of the assets, etc. Existing certification entities (e.g. TÜV SÜD) could be used to deliver such service.
[48] For instance, it is very unlikely that old, previously subsidized hydropower assets would fulfil the requirements of such a PLA. This hypothesis could be further verified in the design of the PLA with case studies.

The administrative effort for this option would be somewhat higher than for new, unsubsidised assets (the necessity of a PLA). From a system perspective, it is not always desirable to prolong the operation of RES-E assets instead of repowering (also discussed previously). However, including such analysis in the PLA is impractical and open to interpretation.

Most of these risks could be managed (to a certain extent) by standardising PLA evaluation and as many of the PLA inputs as feasible (e.g. financial metrics, standard OPEX ranges, and time horizons). Such standards would likely have to be developed by the Commission and rolled out across Member States to prevent various interpretations of the PLA.

Recommendation: Sourcing from new, unsubsidised RES-E assets should be the primary allowed option for deployment additionality. Under this first fulfilment option, the project team recommends allowing both sourcing with a direct contractual relationship (via a PPA, possibly complemented by using GOs) and without a direct contractual relationship (via a subset of eligible GOs from additional RES-E plants). Sourcing from old, previously subsidised assets could also be allowed under specific circumstances, meaning when a PLA provides that a PPA with RFNBO producers makes a difference between closure and continued operation of the asset.

6.4.2 Additionality | Surplus electricity

This section deals with whether—and if so, how—additionality could be fulfilled if RFNBO producers were to consume RES-E that would have been otherwise curtailed (surplus electricity). Such electricity is not additional on an asset level (such as that dealt with in Section 6.3.1) but rather from a megawatt-hour perspective. In other words, if an RFNBO producer could prove they have saved RES-E from some part of a scheduled curtailment, an additionality claim could be made for these energy volumes. The electricity consumed by RFNBO producers during those hours could be suspended from having to prove compliance with the RED II additionality criteria outlined in Section 6.3.1.

There are two main types of (RES-E) curtailment: network-based (technical) and market-based. Network-based curtailment (as part of redispatch) typically occurs due to local lack of transmission or distribution system capacity (e.g. a line or a transformer has already reached its capacity).[49] As for market-based curtailment, it is first important to understand how the dispatch of different electricity sources works. In pure market-based operations, generation is dispatched based on economics (the lowest marginal cost of dispatch), security of supply (must-run generation), and inflexibility (techno-economic limitations) of some (conventional) power plants. Situations in which RES-E generation is self-curtailed might occur (e.g. trying to avoid negative prices). In the past, the effects of market-based curtailment have been reduced by priority dispatch for RES-E. The following sections investigate whether RFNBO operators could help avoid some RES-E curtailment by bidding on negative spot market prices or by participating in TSO-scheduled redispatch.

[49] Other reasons for curtailment due to network constraints include excess generation during low load periods, voltage, or interconnection issues (NREL, 2014).

6.4.2.1 Negative spot market prices

This first option builds on the hypothesis that RES-E assets will self-curtail during negative spot market prices (also called market-based curtailment). One could argue that RFBNO operators, by bidding on low and negative spot market prices, would reduce the occurrence of negative prices and incentivise additional generation from otherwise curtailed RES-E.

How could it be implemented?

RFNBO producers would need to align their production closely with the electricity spot market. In hours with negative prices, they could produce without having to source power from additional assets (see Section 6.3.1) and would be complying with temporal correlation (see Section 6.3.3). RFNBO producers could present their electricity procurement invoices for an audit and megawatt-hours purchased at negative prices would be exempt from deployment additionality.

What are risks and challenges?

There seems to be a consensus that negative prices are typically caused by a lack of flexibility in the electricity system, mainly due to inflexible nuclear, lignite and CHP generation, and demand inflexibility combined with a high infeed of RES-E generation (Agora Energiewende, 2013) (KU Leuven Energy Institute, 2014) (Wind Europe, 2016) (Xiong, Predel, del Granado, & Egging-Bratseth, 2020). The inflexibility on the conventional generation side is due to high costs associated with ramping times and less efficient generation if operated at lower capacity factors.[50, 51] Some inflexibility could also be caused by RES-E assets with fixed FIT schemes that protect them from market signals (e.g. responding to negative prices). In feed-in premium schemes, the RES-E assets would only curtail when negative pricing exceeds the value of the premium they receive (however, the European State Aid Guidelines request that no support be paid in times of negative prices; most Member States have implemented this rule in one way or another).

By looking at the functioning of the electricity markets, the project team concludes that a solid reason for hours exemption at negative spot market prices from deployment additionality is difficult to establish. There are two main reasons for this conclusion:

- The spot market prices are the result of the market, matching supply and demand. Flexible loads (e.g. RFNBO production) bidding into the day-ahead and intraday markets could reduce the occurrence of negative spot market prices and market-based RES-E curtailment, but this bidding would be part of the market clearance. In other words, the negative prices would occur (or not occur) as a result of matching the supply curve (including RES-E) with the demand curve (including RFNBOs). In cases where RFNBO operators bid on negative spot market prices, the electricity consumed would not be surplus electricity, strictly speaking.
- RFNBO production may add demand flexibility to the electricity market, but no particular reason exists to prioritise RFNBO production over other flexible loads by granting them renewability attributes. Such provision would be a privilege and therefore an indirect support measure for RNFBOs.

[50] For instance, lignite plants are operated in a much more load-following fashion than a decade ago. However, they are still largely inflexible generators and are not designed to operate in a more volatile electricity market.

[51] There are other reasons for why some conventional generation is kept running (e.g. inertia, voltage control); these factors are managed by TSOs, mostly on the imbalance market.

The project team therefore recommends that the option of exempting RES-E purchased at times of negative spot market prices from RED II additionality compliance is not considered further.

6.4.2.2 Hours part of redispatch and upward imbalance regulation by TSOs

An alternative to the negative spot market prices option (connected to market-based curtailment) could be the technical curtailment of RES-E. Such curtailment typically results from congestion management and redispatch measures of the TSOs (or distribution system operators in some cases) to avoid situations in which local electricity supply exceeds the grid (transmission or distribution level) capacity. If TSOs conclude in their congestion forecasts that not all electricity scheduled on the day-ahead market can be delivered due to grid constraints, redispatch measures are taken, including (technical) curtailment. Depending on the respective redispatch regulation, RFNBO facilities could be contracted by TSOs to provide flexible load for redispatch, reducing the need to curtail RES-E production.

Next to redispatch, RFNBO facilities could participate in the imbalance markets as balance service providers. Their participation would likely have some benefits to the electricity grids, although the direct link to avoided curtailment is less clear.[52]

RES-E electricity consumed by RFNBOs in redispatch has already been scheduled in the day-ahead market (and could still be refined on intraday). To participate in redispatch or the imbalance market, RFNBOs would have to reserve part of their capacity to be able to deliver the required service at TSO request. Such RFNBO facilities would partly build their business models around the flexibility provision, next to RFNBO production.

How could it be implemented?

Redispatch regulations vary across Member States, but they should allow the use of RFNBO facilities as flexible loads for redispatch. RFNBO facilities could prequalify to provide load flexibility for redispatch; part (or all) of their capacity would have to be available to the TSOs at request, depending on the specific requirements. If located at the right proximity to a congested node, TSOs could use some part of the RFNBO capacity to regulate demand upward and allow for additional RES-E feed-in. In Germany, for example, technical curtailment is regulated in the interruptible load ordinance of the energy industry law, which has the principle of using rather than curtailing RES-E. Interruptible load providers have to prequalify and are selected in a competitive tendering procedure by the TSO based on the price they offer. They are then contracted by the TSO directly. Because such redispatch measures could help to reduce the technical curtailment of RES-E, one could argue that the energy volumes consumed as part of the redispatch measure could be exempt from deployment additionality requirements.

As for the imbalance market, RFNBO facilities would also have to prequalify to provide this service. In fact, thyssenkrupp's electrolysis technology has recently been approved for primary control reserve in Germany, signalling that it could be a feasible option for imbalance settlement (thyssenkrupp, 2020).[53] The energy volumes consumed as part of the imbalance market service could be exempt from deployment additionality requirement. This could be verified by standard imbalance invoices issued by the TSOs to balance-responsible parties.

[52] The imbalance market mostly deals with grid stability and frequency issues, and its primary purpose is not to avoid RES-E curtailment.

[53] This might be problematic in more integrated systems that produce more complex RFNBOs than just hydrogen (e.g. synthetic methane, kerosene, diesel).

These invoices contain the imbalance price and energy volume (in megawatt-hours) for each quarter-hour (Elia , 2020).

Avoiding curtailment through the system-friendly placement of RFNBO facilities could be further incentivised by Member State governments defining RFNBO-suitable areas in collaboration with TSOs and distribution system operators.[54] This collaboration is further addressed in Section 6.3.4.3.

What are risks and challenges?

Similar to the market-based curtailment described in Section 6.3.2.1, providing flexibility for redispatch is usually a market-based mechanism.[55] RFNBO operators could choose to participate in tenders for flexibility in the same way as other flexibility providers. If RFNBO facilities were privileged compared to other flexibility providers by granting them renewability attributes, this would be an indirect support measure. The RES-E supply for which curtailment is avoided has already been scheduled as day-ahead and is taking part in the electricity market. Therefore, it seems questionable to exempt the hours where RFNBO facilities were part of a redispatch mechanism from deployment additionality requirements.

Similarly, RFNBO operators could choose to participate in the imbalance market. However, this is also a market-based mechanism where alternatives can compete against each other to provide the required service at the least cost. Following the same line of reasoning, the project team does not see a rationale for exempting the hours where RFNBO facilities were part of the imbalance market from deployment additionality requirements.[56] The project team therefore recommends that exempting RES-E purchased as a consequence of participating in TSO redispatch or the imbalance market from RED II additionality compliance is not considered further, unless there is a policy decision to support and privilege these options over other demand-side flexibility options.

Recommendation: The project team recommends that surplus electricity is not addressed directly by the DA for Case 3 because, strictly speaking, "surplus electricity" is a result of the electricity market clearance that it difficult to accommodate ex-ante. Using RFNBO production in times of negative market prices or for redispatch would increase demand-side flexibility, but granting them renewability attributes would privilege them over other flexibility options and therefore be an indirect support measure. Surplus electricity can be used in Case 2, where otherwise curtailed electricity can be used through a direct connection. Additionally, this issue is indirectly addressed through temporal and geographical correlation.

6.4.3 Temporal correlation

Recital 90 demands a temporal correlation between RES-E generation and RFNBO production in the sense that RFNBO would not be produced when RES-E is not generated at the same time. Matching electricity generation (GOs) and consumption on an annual basis is

[55] Cost-based redispatch is not discussed, but the basic arguments in relation to additionality of surplus electricity would still apply.

[56] Conversely, the volumes in the imbalance markets are very small—for instance, TenneT has 310 MW in aFRR and 994/705 MW (up/down) mFRRda as of 2020 (TenneT, 2020).

common practice in RES-E sourcing. Annual matching merely indicates the coexistence of the RES-E unit and the consumer, but it does not ensure the simultaneity of RES-E generation and consumption, even in the same season. A continuous baseload demand throughout a year could be met by a solar power plant exceeding that demand during the summer and subceeding it during the winter. As a result, annual matching is not considered compliant with Recital 90. Higher temporal correlation on monthly, daily, and hourly basis is discussed in the following sections.

In the first phase of this project, the project team investigated various options by which temporal correlation could be fulfilled (see Appendix 10.3). It has been concluded that the following options should be analysed further as they are most suited:

- Full intraday matching with RES-E unit(s) contracted through PPA(s)
- Monthly or daily matching with any RES-E unit(s) through GOs
- Full intraday matching with any RES-E unit(s) through GOs
- Intraday matching with RES-E generation on the system level

Each of these options is discussed in detail in the following subsections.

6.4.3.1 Full intraday matching with RES-E unit(s) contracted through PPA(s)

With this option, one or more renewable PPAs exist between the RFNBO producer and one or more RES-E units. RES-E generation is taken off as produced (i.e. the RES-E generation profile is not converged into a baseload profile by trading on the power market). RFNBO production is only taking place when the contracted RES-E asset is generating electricity.

Hourly and quarter-hourly supply and demand matching can be considered a guarantee for simultaneity (i.e. temporal correlation) and require only a low level of flexibility or inertia in the system capable of balancing short-term deviations between supply and demand. RES-E forecast and infeed data is usually available on quarter-hourly basis. Hourly intervals are deemed more appropriate and compatible with electrolysers' capabilities to change the load. Also, from a power procurement perspective, hourly matching is deemed more appropriate as the day-ahead market concludes contracts in one-hour blocks. Key to understand here are also the technical parameters of the electrolysers: their minimum (must-run) load and their hot idle and cold idle ramp time. The minimum load for PEM and ALK technologies is around 10-15% of their nominal capacity (industrial size models), so it is essential that at least the minimum load is always achieved.[57] As for accommodating supply fluctuations, PEM and ALK are, in principle, suited to deal with quarter-hourly matching if starting from hot idle setting (hence, in principle, at or above minimum load). In HTE, however, this might be problematic due to much longer hot idle ramp times. As for cold idle ramp times, only PEM would currently be able to physically respond to the requirement of quarter-hourly matching. Quarter-hourly matching could still be required. However, some of the produced hydrogen would not necessarily qualify as RFNBO (e.g. at times of a quick and substantial generation ramp up or down by the affiliated RES plant or plants).

How could it be implemented?

The project team's proposal is that the existing, contracted RES-E infeed should be used to monitor compliance. Studies show that forecasts for single RES-E assets tend to be less accurate than on an aggregated system level. The (root-mean-squared) error of a day-ahead

[57] This is due to several reasons including stack degradation by repetitive cycling, safety and hydrogen purity requirements (Hydrogen Europe, 2020b), (Gusain, 2020).

forecast for a single wind farm is about 4 times larger than for a large region with distributed wind farms. [58] Official public forecast data from TSOs is only available on system level. For single assets, third parties provide forecasts. As forecasts for single assets may be less accurate and less independent, the project team suggests that existing infeed data is used for monitoring.

GOs cannot serve as a vehicle to verify intraday matching unless their temporal granularity is increased by the issuing bodies. In today's practice, GOs are usually issued on a monthly basis, only earmarking the month of RES-E generation, not the date and time.

Rather than aligning RFNBO production with the expected RES-E generation profile of single RES-E units, which would be difficult in practice, producers may contract a diversified portfolio of RES-E units. A balanced mix of solar, wind, or other renewable energy sources can result in a continuous RES-E generation profile and allow for continuous RFNBO production.

What are risks and challenges?

RFNBO production plants needs to cope with load changes (ramping). If the plant cannot cope with this, other measures need to be taken, such as installing flexibility solutions on the supply or demand side (e.g. behind-the-meter batteries) or the RFNBO production switches between Case 3 (contracted RES-E) and Case 1 (average grid electricity). Alternatively, RFNBO producers would have to accept that part of the produced hydrogen batch would not qualify as RFNBO. Inherently, there will be an economic trade-off between taking additional measures to prevent such situation (e.g. behind-the-meter batteries as mentioned above) and economic loss due to non-RFNBO production (e.g. loss of subsidies). Under this option, the utilisation of the RFNBO asset would be limited by the RES-E infeed of the contracted assets, making production potentially more expensive for RFNBO producers than the other options for temporal correlation discussed below. From a system cost perspective, this may be justified compared to softer forms of temporal correlation on project level (as described in 6.4.3.2) but not compared to temporal correlation on system level (see 6.4.3.4), which reflects the value of RFNBO production for the power system.

If the existing infeed by contracted RES-E assets is used to monitor temporal correlation, RFNBO producers would need to align their production in real-time with the corresponding electricity production. They may also plan the production (e.g. based on intraday or day-ahead forecasts). This planning would, however, create a profile risk: RES-E production could be less than expected (leading to producing some loss-making non-renewable fuel) or more than expected (leading to opportunity costs because more RFNBO could have been produced). RFNBO producers are still able to contractually outsource that profile risk, but outsourcing would increase the negotiated PPA price.

6.4.3.2 Monthly or daily matching with any RES-E unit(s) through GOs

For this option, GOs produced on the same day or in the same month are claimed to match the total electricity consumption of an RFNBO plant on a given day or month. This option would give RFNBO producers more flexibility than being coupled to a specific contracted RES-E asset and reduce the economic burden. However, it would not be in line with Recital 90 of RED II, which requests that RFNBOs "cannot be counted as fully renewable if they are produced when the contracted renewable generation unit is not generating electricity." This

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[58] Federal Ministry for Economic Cooperation and Development. *Variable Renewable Energy Forecasting – Integration into Electricity Grids and Markets – A Best Practice Guide.* 2015. **https://energypedia.info/images/2/2a/Discussion_Series_06_Technology_web.pdf**.

option should only be considered as a transitional solution until better options for proving temporal correlation are in place.

How could it be implemented?

The RFNBO producer procures GOs with time stamps from the month or day of RFNBO production. Daily matching would require issuing bodies to issue GOs with more granular time stamps, which requires network operators to report metering data more frequently. RFNBO producers would need to rely on the assumption that sufficient RES-E infeed and GOs would be available on the GO market. They would need to plan production in line with RES-E infeed forecasts.

What are risks and challenges?

Matching supply and demand on a monthly basis may account for seasonal fluctuations of RES-E generation. The producer may source GOs from units with no or low seasonal fluctuation (e.g. hydro, geothermal, bio) or from a mix of units. Still, the simultaneity of RES-E generation and consumption would not be guaranteed. GOs are limited to monthly matching.

Daily RES-E generation and RFNBO production matching would account for fluctuations in wind supply and solar radiation to some extent, but it still falls a bit short of a full guarantee of simultaneity and necessitates system flexibility. Daily matching is not possible with the frequency at which GOs are issued.

Even though this option provides weak temporal correlation, GO procurement is more complex compared to the current practice where GOs are usually procured on an aggregated level in bulk with time stamps referring to a specific year, not a specific month or day. Energy or service providers charge consumers a premium if they ask for a detailed and verified matching between their consumption and a specific RES-E unit rather than the provider's aggregated pool of RES-E units.

6.4.3.3 Full intraday matching with any RES-E unit(s) through GOs

GOs with highly granular time stamps that could be claimed and matched with consumption on an hourly basis would need to be implemented. Hourly supply and demand matching provides a high certainty of simultaneity. In comparison to quarter-hourly intervals, hourly intervals are deemed more appropriate and compatible with electrolysers' capabilities to change the load.

How could it be implemented?

The RFNBO producer procures GOs with time stamps from the hour of RFNBO production, which would require a change in the GO system. Hourly or daily matching is not possible with the granularity of information embedded in GOs.

What are risks and challenges?

The key challenge is that an advanced GO system capable of providing certificates with detailed time stamps needs to be established. Some market players and initiatives are making proposals for such a mechanism, but it is unclear if and when a reliable, appropriate mechanism will be available. In the case of small RES-E units or low load factors, matching is limited by the time it takes an installation to generate 1 MWh of electricity (the unit of a GO).

6.4.3.4 Matching with RES-E generation on system level

Under this option, RFNBO production can occur when the RES-E share in the system exceeds the system average (measured 2 years prior for data availability reasons). RFNBO production would be temporally correlated in hours with higher-than-average RES-E supply in the respective system (the system is usually the bidding zone, see Section 6.3.4). Such an approach has also been suggested by some Member States (AT, DK, ES, IE, LU, PT, 2020).

In electricity systems with still-significant non-renewable generation, the system perspective could be more meaningful when determining whether an RFNBO plant consumes RES-E. Considering the system perspective would ensure a higher contribution of RFNBO production towards RES-E system integration (i.e. RFNBOs would be produced in hours of high RES-E infeed and serve as flexible load).

A disadvantage of this approach is that it does not reflect the actual RES-E share of a country, i.e. RFNBO producers in Member States with high RES-E shares would not get more FLH than in countries with low RES-E shares. The number of FLH would only be derived in relation to the national RES-E average.

How could it be implemented?

RFNBO production is planned based on the day-ahead or intraday forecast of national RES-E production.[59] RFNBOs can be produced in times of RES-E shares above the national average of the year 2 years prior. Depending on the definition of geographical correlation (see Section 6.3.4), the RES-E share in the bidding zone rather than the national average may be used as benchmark. For auditing, the project team suggests that day-ahead or intraday forecasts and consumption are compared and verified.

RFNBOs producers could still be obliged to procure GOs to make sure the equivalent RES-E volume can be claimed. However, as temporal correlation is tackled by aligning RFNBO production with RES-E generation on the system level, GOs may refer to RES-E generation with any time stamp. Basic GO requirements (i.e.GOs expire after 12 months) ensure a minimum (yearly) temporal correlation.

What are risks and challenges?

This shift to system perspective deviates from the wording of Recital 90, but it would be in line with its objective (RFNBOs should not operate at times of no or low RES production). The project team proposes using forecast data to monitor compliance rather than the existing RES-E infeed. This use of data would grant RFNBO producers some predictability regarding their load and their output of compliant RFNBO. The RFNBO production plant still needs to cope with load changes (ramping), and continuous production can only be achieved through additional flexibility solutions (energy storage).

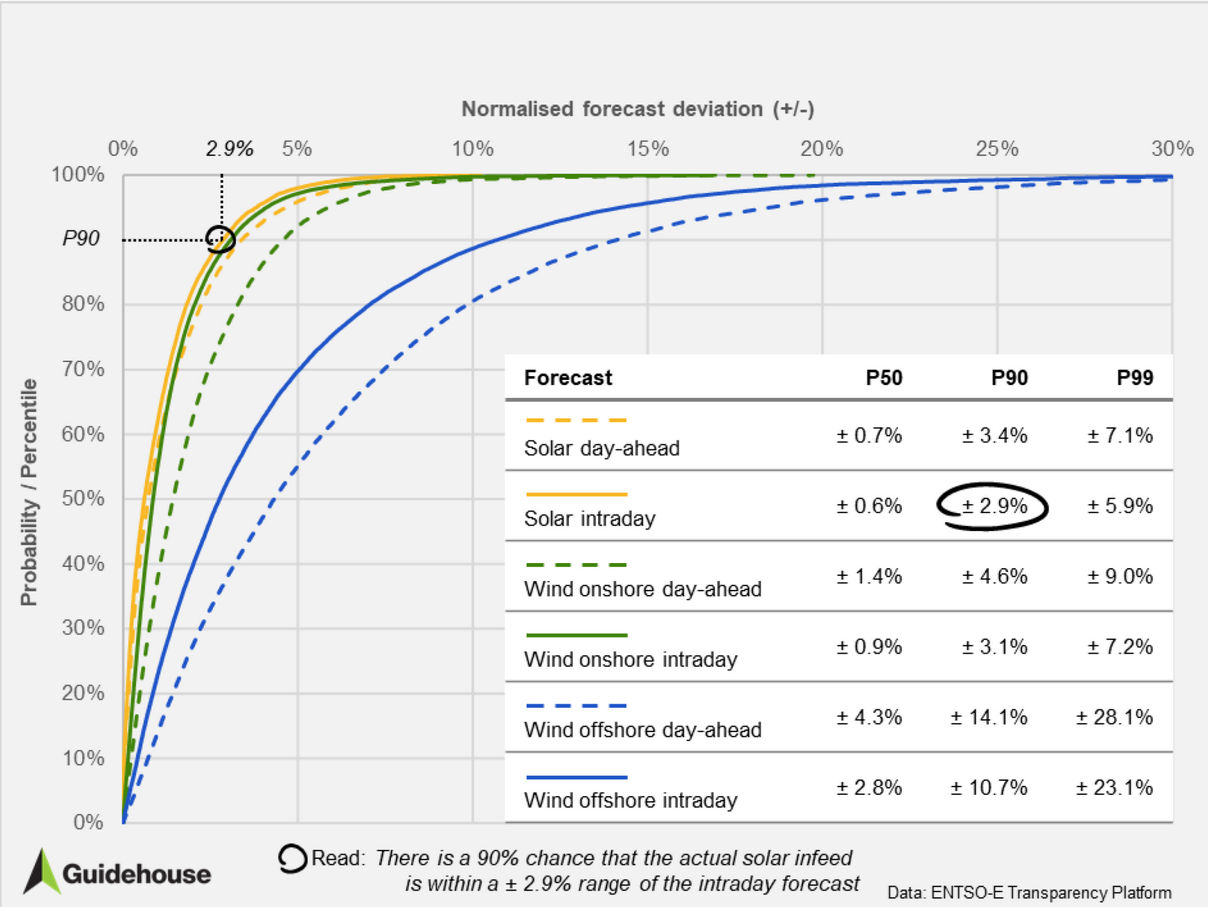
Day-ahead or intraday forecast data from grid operators may be used. The project team deems the day-ahead forecast as the preferable compromise between accuracy and planning security. Figure 15 provides an analysis of the accuracies of RES-E forecasts

[59] This data is available from grid operators (e.g. National Grid ESO. "Datasets." **https://data.nationalgrideso.com/search?q=wind;** TenneT. "Energy Transition." **https://www.tennet.eu/e-insights/energy-transition/**) or commercial data providers. Day-ahead forecasts are published by TSOs before 18:00 on the day before RES-E delivery takes place. Intraday forecasts are published by TSOs before 8:00 on the day of RES-E delivery.

(day-ahead and intraday) versus the existing infeed for solar power and onshore and offshore wind in Germany in throughout 2020.[60]

- The accuracy of day-ahead forecasts of RES-E generation from solar is quite high. Intraday forecasts only slightly improve accuracy. Ninety percent of the time, the day-ahead forecast is plus-or-minus 3.4% accurate. The updated intraday forecasts reduce this range to plur-or-minus 2.9%.
- For onshore wind power, the day-ahead forecast deviates a little more from the intraday forecast. Still, the day-ahead forecast is less than 5% off 90% of the time.
- For offshore wind power, existing generation deviates more from day-ahead and intraday forecasts. This deviance may be because the technology is younger and the total capacity smaller, and it may improve in the future.

Figure 15. Analysis of RES-E forecast accuracy



Overall, using intraday forecasts instead of day-ahead does not seem to be a significant improvement for system integration. In order to receive a 100% match between certified RFNBO and RES-E production, the calculation could be based on existing RES-E generation rather than the day-ahead or intraday forecast. Contrary to the case of using forecasts, RFNBO consumption in this case would be counted in the grid mix, which is an advantage. This counting method would, however, impede the operation and economies of

[60] The analysis is based on data from the public ENTSO-E Transparency Platform. "Generation Forecasts for Wind and Solar", "Actual Generation per Production Type" and "Installed Capacity per Production Type." **https://transparency.entsoe.eu/**.

RFNBO production (see 6.4.3.1). It would also add little system integration benefits because the forecasts for the most widespread RES-E technologies (solar and onshore wind) are already accurate, with less than 5% deviation more than 90% of the time (see Figure 15).

Table 3 shows an example calculation of the full load hours RFNBO producers can achieve under this option. The values are based only on intermittent RES-E because these are the generation technologies[61] that require complimentary loads.[62] In case total RES-E shares are used, the variations in hydropower generation would have to be normalised to avoid significant annual variations in FLH (the same may apply for the seasonal effect of wind energy; such potential variations need to be further investigated). The table is based on existing generation, not on the day-ahead forecast as the project team previously proposed. Therefore, it does not serve as an exact example of the methodology but is an estimate for the anticipated load factors.[63]

[61] These technologies are onshore wind, offshore wind, and solar PV. Hydropower and bioelectricity are not included.

[62] The methodology could also be based on total RES-E share rather than only intermittent RES-E. This option may be simpler, but it may slightly reduce the system integration benefit of this option because renewable generation that does not require demand-side flexibility (e.g. hydropower or bioelectricity) would also be included in the calculation. Also, this may lead to larger variations in RES-E generation patterns and resulting FLH.

[63] The project team has delivered a more extensive analysis of the system level temporal correlation options to the Commission separately from this report.

Table 4. Intermittent RES-E share in total generation of EU-27 Member States

Country	Average intermittent RES-E share in total generation 2019 (%)	Hours with intermittent RES-E share above average 2019 (hrs)	Hours with intermittent RES-E share above average 2019 (%)
Denmark	56%	4,860	55%
Lithuania	39%	4,517	52%
Ireland	36%	4,375	50%
Germany	30%	4,176	48%
Portugal	29%	4,107	47%
Spain	26%	4,181	48%
Greece	25%	4,136	47%
Italy	15%	3,903	45%
Austria	14%	3,763	43%
Romania	13%	3,786	43%
Estonia	13%	3,602	41%
Belgium	13%	4,173	48%
Croatia	12%	3,940	45%
Sweden	12%	3,975	45%
Poland	10%	3,646	42%
Finland	9%	3,709	42%
France	8%	3,810	43%
Netherlands	7%	3,748	43%
Bulgaria	6%	3,595	41%
Cyprus	5%	3,037	35%
Czechia	4%	2,718	31%
Latvia	3%	2,913	33%
Hungary	3%	3,364	38%
Slovakia	2%	2,697	31%
Slovenia	2%	2,595	30%

Source: Guidehouse calculation based on generation data from ENTSO-E

As Table 3 shows, load factors around 50% can be achieved in most countries. One would expect that roughly half the time the RES-E share in the grid is below average and half of the time the RES-E share is above it. The load factor that RFNBO producers can achieve under Case 3 could be higher than Table 3 indicates:

- For this option, temporal correlation can be combined with correlation with contracted RES-E assets, as outlined in Section 6.3.3.1. RFNBO producers would have the option to increase their utilisation by correlating with the system and contracted RES-E producers, reducing costs.
- Due to data availability, the benchmark would not be the annual RES-E average of the same year but that of 2 years prior. Assuming RES-E shares generally increase over time, the existing RES-E infeed will more often be above the average 2 years prior, allowing for more hours of production.

In some countries with low intermittent RES-E shares (5% and less), the achievable load factor drops to below 40%. This result could pose an economic issue for RFNBO producers because they have to refinance their investments over smaller fuel volumes. The project team does not propose introducing a special provision for such cases for the following reasons:

- Sourcing RES-E only through the wholesale market is more challenging in countries with low RES-E penetration. Therefore, it is sensible that RFNBO producers in such countries need to directly add to RES-E deployment through a PPA under Case 3—or even Case 2.
- RES-E shares are set to increase across the EU. Given that Table 3 shows a greater than 40% load factor at intermittent RES-E shares that are greater than 5%, this problem can be expected to disappear in a few years.

Recommendation: GOs are not an appropriate vehicle to verify temporal correlation because they only earmark the month of RES-E production, which is not sufficiently granular. Hourly GOs could be used in the future, should they become available. The DA should, therefore, mainly rely on ensuring temporal correlation either between RFNBO production and RES-E production with a directly contracted asset (a PPA) or based on a comparison with the current RES-E share in the grid or a combination. The latter may be carried out through matching RFNBO production planning with the day-ahead RES-E infeed forecast. RFNBO producers may install or contract electricity storage capacity to decouple their time of production from RES-E generation.

6.4.4 Geographical correlation

In the first phase of this project, the project team investigated various options by which geographical correlation could be fulfilled (see Appendix 10.3.4). It has been concluded that the following options should be analysed further as they are most suited to fulfil the intention of the geographical correlation requirement:

- RFNBO and RES-E production located in the same country
- RFNBO and RES-E production located in the same bidding zone
- RFNBO and RES-E on the same side of grid congestion within a bidding zone
- RFNBO and RES-E in different zones, if coupling capacities allow

Each of these options is discussed in detail in the following subsections.

6.4.4.1 RFNBO and RES-E production located in the same country

Each unit of RES-E that an RFNBO asset consumes, claimed through a PPA or a GO, must come from RES-E assets located in the same country. This option was chosen for further analysis because it would create minimal administrative burden and would be easy to verify globally.

How could it be implemented?

In the case of a PPA, the RFNBO producer would need to choose an RES-E-supplying counterparty located in the same country. This requirement is usually the case with PPAs. Compliance could be verified ex ante by checking the PPA.

In case of RES-E procurement through the wholesale market and GOs, RFNBO producers would need to set up GO procurement in a way that facilitates purchasing GOs that originated in the same country. Verification would need to be carried out ex post by auditing all GOs claimed, but this process can likely be automated.

What are risks and challenges?

Being located in the same country would not determine that RFNBO and RES-E production are not separated by a grid bottleneck. There are already EEA countries with several bidding zones on their territory due to such grid constraints (e.g. Italy, Sweden, and Norway). As an extreme example, RFNBO production in northern Italy could claim correlation with a RES-E asset in Sicily, although grid bottlenecks exist between the two, as evidenced by the crossing of four bidding zone borders. This option should only be used in countries where a more suitable definition for geographical correlation does not exist—e.g. by bidding zones or separate electricity networks (see Section 6.4.2.2).

6.4.4.2 RFNBO and RES-E production located in the same bidding zone

Each unit of RES-E that an RFNBO asset consumes, claimed through a PPA or GO, must come from RES-E assets located in the same bidding zone. Bidding zones are meant to represent liquid electricity markets; Regulation (EU) 2019/943 defines them as the "largest geographical area within which market participants are able to exchange energy without capacity allocation." This option would provide a requirement as simple as the previous option, relying on countries, but it would take grid bottlenecks within countries in account to some extent. In Italy or Sweden, for example, several bidding zones exist due to grid constraints. RFNBO producers would need to respect this when sourcing RES-E.

How could it be implemented?

In the case of a PPA, the RFNBO producer would need to choose a RES-E-supplying counterparty located in the same bidding zone. Compliance could be verified ex ante by checking the PPA and should be granted for the entire duration of the PPA. Over this long period, economic operators are guaranteed relief from the risk that if bidding zones are split, the two parties of the PPA could end up in different zones, and the PPA could no longer produce RFNBOs compliant with geographic correlation.

In case of RES-E procurement through the wholesale market and GOs, RFNBO producers would need to set up GO procurement to facilitate purchasing GOs that originated in the same bidding zone. Verification would need to be carried out ex post by auditing all GOs claimed, but this process can likely be automated.

If temporal correlation is determined at the system level, RFNBO production would be planned according to the day-ahead forecast for RES-E infeed in the respective bidding zone. Compliance would be verified ex post by comparing the day-ahead forecasts and the actual load profile of the RFNBO production.

What are risks and challenges?

A potential issue with this option is that it may not warrant the Recital 90 text that both assets "are located on the same side in respect of the congestion" because there are cases where structural grid bottlenecks exist within bidding zones, as outlined in ACER's 2018 market monitoring report (ACER, 2019). The bidding zone review process analyses this possibility and may lead to bidding zone splits to reflect physical grid constraints. The definition of geographical correlation through bidding zones automatically adapts to these developments. However, the bidding zone review process may be insufficient for the objectives of this regulation, and governments may want to proactively avoid the creation of new grid congestion by RFNBOs, making potential refinements necessary (as discussed in Section 6.4.3.3).

Open electricity markets and bidding zones may not exist in some third countries. In smaller countries, geographical correlation may need to be determined via country borders (see Section 6.4.3.1). In cases of larger countries with separate electricity networks (e.g. Mongolia or Saudi Arabia), these subnational networks may be used as a proxy for bidding zones when establishing geographical correlation.

6.4.4.3 RFNBO and RES-E on the same side of grid congestion within bidding zone

The definition of geographical correlation purely through bidding zones does, by nature, consider intra-national grid bottlenecks, but it falls short in two important aspects:

It does not reflect existing grid constraints in countries that still consist of one bidding zone.

It does not take into account that RES-E expansion will most likely create more grid constraints in the near future. RFNBO producers in the wrong locations may aggravate these constraints and become located on the wrong side of a new grid bottleneck that they created.

Member States may want to plan ahead and designate RFNBO-suitable areas for RFNBO production where grid congestion caused by RFNBOs is unlikely. Some Member States have proposed that electrolysers be used to address grid congestions in the context of this DA (AT, DK, ES, IE, LU, PT, 2020). Literature review also suggests that, by placing and operating electrolysers at congested nodes, significant RES-E curtailment could be avoided (Xiong, Predel, del Granado, & Egging-Bratseth, 2020).

How could it be implemented?

This option would require implementation efforts by economic operators and public authorities. By default, RFNBO producers would have to comply with geographical correlation based on bidding zones. If a Member State realises that it does not suffice to avoid the separation of RFNBO and RES-E production by grid bottlenecks, it may decide to refine the bidding zone demarcation by designating areas for RFNBO production.

With the support of TSOs, the respective national authorities would identify areas where grid congestions due to RFNBO production are considered unlikely or where RFNBO production would help to reduce congestion. These areas would typically present large RES-E potentials relative to the local electricity demand (e.g. coastal areas with wind resources or sparsely populated regions with high solar irradiation). RFNBO production facilities in these areas would be considered compliant with the geographical correlation requirement due to their location. This compliance would be confirmed by ex-ante certification and would hold for the technical lifetime of the RFNBO asset.

RFNBO producers would avoid or alleviate grid constraints primarily by placing their load in the right area. It would be sufficient to demand they source RES-E (through PPAs or GOs) from the same bidding zone as opposed to requiring them to source from the same RFNBO-suitable area:

Sourcing RES-E from the same area is the most likely scenario because these RFNBO-suitable areas will typically exhibit an RES-E oversupply. If RFNBO producers do so, it would constitute a strong compliance with geographical correlation requirements.

Sourcing RES-E from outside the RFNBO-suitable area would seem like less geographical correlation. It would, however, further support the grid because the RFNBO producers would add to RES-E deployment in areas that experience a structural shortage of RES-E supply.

The location of the RES-E asset that produced the GO to prove additionality, for instance, would consequently not be the primary criterion for fulfilling geographical correlation.

What are risks and challenges?

RFNBO production outside of RFNBO-suitable areas would not be considered to fulfil the requirement of geographical correlation. It would not be possible to produce RFNBOs under Case 3 outside of the RFNBO-suitable areas once a Member State has designated such areas. RFNBO consumption outside these areas would have to rely on physical RFNBO transfers from elsewhere. For liquid fuels or methane, this does not pose a problem, but for hydrogen, transmission infrastructure exists only in few places.

While this option could become a substantially restrictive measure, it does reflect the purpose of Case 3, which allows for using the grid as long as no structural grid bottlenecks obstruct RES-E supply. In regions where structural grid bottlenecks lead to difficulties with RES-E supply, it is logical that Case 3 cannot be applied. RFNBO producers can respond by adding RES-E close to their production site outside of RFNBO-suitable areas, which would alleviate grid constraints and allow them to employ Case 2 for RFNBO production.

Whether or not this option of refining geographical correlation within bidding zones will be used depends on Member States. Governments have an intrinsic interest in reducing the burden on the national grid and introducing stricter national requirements, if needed. However, governments may want to incentivise RFNBO production with a low regulatory burden and refrain from using this approach. If RFNBO-suitable areas are not assigned, even though there are structural bottlenecks within a national bidding zone, RFNBO and RES-E production may be located on different sides of the bottleneck, which would be against the requirement established in Recital 90 (see Section 6.1.4).

This risk could be mitigated by establishing RFNBO-suitable areas in a harmonised pan-European approach for RFNBO production rather than only granting the option to Member States. The basis for such an approach could be respective reporting by ENTSO-E and ACER in the bidding zone configuration technical report (ENTSO-E, 2018). Defining liquid electricity systems within bidding zones across Europe would be a complex undertaking, requiring alignment of the concerned national parties from all countries involved. Individual national approaches, where needed, seem to be a more practical approach in this case. If the approach of establishing RFNBO-suitable areas remains voluntary for Member States, the question remains whether it would need to be part of the DA or whether Member States would be able to take such regulatory measures under national law.

6.4.4.4 RFNBO and RES-E in different zones if coupling capacities allow

In some cases, there may be sufficient transmission capacities between bidding zones to argue that RFNBO and RES-E assets are in different zones but with no grid bottleneck between them (Power to X Alliance, 2020; Shell, 2020; SolarPower Europe, 2021). This would fulfil the RED II objective of no congestion between RFNBO and RES-E production. In the light of EU targets for interconnection capacities, cross-border electricity flows within

Europe are expected to meet less physical constraints going forward, making this a realistic scenario. To this end, the DA should allow for cross-border RES-E sourcing if it can be demonstrated that no structural grid bottlenecks are separating the two zones.

How could it be implemented?

This option would require implementation efforts by economic operators and by public authorities. RFNBO producers intending to source cross-border RES-E would need to approach the respective TSOs or national authorities to demonstrate that sufficient interconnection capacities exist. This sufficiency would be proven ex ante and facilitate compliance for the technical lifetime of the RFNBO asset to grant investment safety.

Alternatively, TSOs or national authorities could decide to establish a specific border as sufficiently interconnected and provide the required evidence. In this case, RFNBO projects would not need to proactively request and collect the evidence by themselves. This scenario could be viable in the case of creating offshore bidding zones.

The electricity price spread as projected by ENTSO-E could be an indicator to decide whether there is sufficient transmission capacity between two zones (ENTSO-E, 2020). If price spreads at one border are projected to stay small (e.g. less than 5 EUR/MWh) over the coming 10-20 years, the two zones might be considered as one zone to fulfil the requirement of geographical correlation for RFNBO production.

What are risks and challenges?

Examining the adequacy of interconnection capacities requires a sophisticated technical analysis. RFNBO producers intending to source RES-E cross-border would have to rely on the cooperation of national authorities and TSOs to provide the evidence required.

Compliance would need to be granted to RFNBO projects ex ante for their entire technical lifetime to ensure investment safety. This could mean that RFNBO can consume electricity at times when cross-border capacities are fully utilised. Such a scenario would undermine the concept of geographical correlation. Two potential solutions for this are as follows:

Assessing the adequacy of interconnection capacities in real time. This solution would, however, be completely impractical for RFNBO producers. Due to the uncertainty of this approach, they would not be able to close a cross-border PPA, and it would add a level of complexity to GO sourcing that would likely be prohibitive.

Impose strict requirements for the definition of sufficient interconnection capacities (i.e. a strong predicted price convergence between the two zones).

Projections on the future development of price spreads between zones are linked to extremely high uncertainty. While grid capacities may be somewhat predictable through 10-year network development plans, developing electricity generation and demand depend on numerous economic and political factors in each country. If price convergence predictions are inaccurate for these reasons, RFNBO projects that have been granted compliance for their entire technical lifetime would claim to consume RES-E cross-border, even though the corresponding transmission capacities are scarce. This risk could be partly mitigated by imposing strict requirements for the definition of sufficient interconnection capacities, but it cannot be excluded due to the underlying complexity.

Recommendation: Bidding zones should be the default rule of geographical correlation because they provide a clear definition and consider grid bottlenecks to some extent. Member States should be allowed to refine this option by designating RFNBO-suitable areas for RFNBO production. National authorities or TSOs should also be allowed to permit cross-zonal RFNBO and RES-E production if bidding zones are sufficiently interconnected. In countries where the electricity market is not developed enough to use these options, the country territory may need to be used as a fallback definition for geographical correlation.

6.4.5 No double counting

6.4.5.1 Member States accounting

The electricity-based RFNBO process chain's deployment generates RES-E as an intermediate product and renewable final energy consumption in the transport sector. Thus, the renewable energy can arguably be counted either in the electricity sector or in the transport sector. Distortive effects arise when these amounts are simultaneously counted in both sectors, which needs to be avoided.

How could it be implemented?

Aspects concerning target calculation would need to be implemented at the EU level and in Member States; it does not directly address economic operators. In principle, excluding double counting is explicitly contained in Article 7, which states that "electricity and hydrogen from renewable sources shall be considered only once for the purposes of calculating the share of gross final consumption of energy from renewable sources." Article 27 makes the same point regarding the RES-T sector target. It states that renewable electricity should be counted "only in one end-use sector." Regarding the attribution of the electricity consumed in domestic RFNBO production, the RED II states, to the project team's understanding, the following:

- For the overall RES target (Article 3), this electricity is counted towards the gross final consumption of electricity from renewable sources.
- For the transport sector RES target (Article 25), the renewable energy contained in RFNBOs is attributed to the transport sector.
- Counting RFNBOs in more than one end-use sector is prevented by the reporting duties already in place, and their renewable property is claimed only once when calculating the total share of renewables for Member States.

6.4.5.2 No double claim at RFNBO producer level

At the producer level, double claiming the renewable properties of the electricity source for the RFNBO installation could occur. Unless the origin of the electricity is unambiguously determined, two different RFNBO producers could claim that the same renewable installation sources their facility, which needs to be avoided.

Proving renewability of a unit of fuel or electricity can only be completed via a label that certifies the renewability via GOs for the electricity or the label RFNBO. Both can be disclosed to customers. If the RES installation is not granted GOs in the first place, double counting is not possible because the renewable property is only disclosed to a customer via the RFNBO label. Moreover, if the fuel is not marketed as RFNBO, there is no possibility of double claiming. Therefore, it can only occur if the GO continues to circulate after it is used by an RFNBO producer to claim renewability for its consumption.

How it is implemented?

This situation can be effectively precluded within the existing certificate system (see Section 6.2.1 for details on GOs). First recital (55) of RED II states: "Energy from renewable sources in relation to which the accompanying guarantee of origin has been sold separately by the producer should not be disclosed or sold to the final customer as energy from renewable sources." This rule prevents RFNBO producers from claiming renewability unless they also buy the accompanying GO. If they do, the requirement to cancel an electricity GO when the electricity is converted into a fuel prevents any possibility of double counting.

What are risks and challenges?

As long as GOs are used to source RES-E under Case 3, there is no risk of double counting towards end consumers. Such a risk exists only for Case 1 and is discussed in Section 4.1.3.

Recommendation:

Double counting renewable energy properties in the context of RFNBOs at the Member State level is prevented by the reporting duties in place under RED II. To prevent double counting towards end consumers, RFNBO producers should cancel any GOs they use to claim the renewability of their consumed electricity.

6.4.6 Eligible sourcing models for renewable grid electricity

In conclusion, Table 4 summarises the findings and recommendations and describes the proposed sourcing models for RES-E and how the requirements under Case 3 can be met.

Table 5. Options for RFNBO producers to demonstrate compliance with renewability criteria depending on RES-E sourcing model

Requirements	Model I: Contracted RES-E (PPA)	Model II: Wholesale RES-E (grey electricity + GOs)
Deployment additionality	• New assets: PPA specifies date of initial operation and (absence of) subsidies • Old assets: PPA specifies (current absence of) subsidies; PLA necessary to confirm additionality	• New assets: GOs specify date of initial operation and (absence of) subsidies • Old assets: GOs specify (current absence of) subsidies; PLA necessary to confirm additionality
Temporal correlation	• Load profile of RFNBO production and infeed of RES-E production of contracted unit(s) match	• Load profile of RFNBO production and forecast of RES-E production above average match • (If available in the future: hourly GOs specify hour of RES-E production)
Geographical correlation	• PPA specifies location of RES-E unit(s) within the same bidding zone as RFNBO production (or designated area if applicable in Member States)	• GOs (and, if applicable, forecast) refer to same bidding zone (or designated area if applicable in Member States) as RFNBO production

Source: Guidehouse

Model I requires one or multiple bilateral contracts (PPAs) to be in place. Contracted RES-E units need to be located in the same bidding zone as the RFNBO production and meet age or financial requirements. RES-E production profiles also need to match RFNBO load profiles. Model I does not necessarily involve GOs. However, the project team recommends that GOs issued to contracted RES-E suppliers should be cancelled to prevent other RFNBO producers applying Model II from claiming the same additional renewable property. Alternatively, the RES-E generator could prove that they are not issuing GOs, making the transfer of GOs in Model I unnecessary.

Model II does involve GOs as a proof for sourcing additional renewable electricity. RFNBO producers may procure electricity on the wholesale market at appropriate times along with suitable GOs that specify the absence of subsidies. If GOs from RFNBO-PPAs under sourcing Model I are not cancelled but enter the GO market, there would be a risk of double counting, deteriorating additionality. To avoid this risk, the PPA RES-E generator could prove that they are not issuing GOs.

The project team recommends that RFNBO producers can choose Model I (PPAs), Model II (GOs), or both, as proposed by many stakeholders (VDMA, 2020) (Power to X Alliance, 2020) (Vattenfall, 2020) (AT, DK, ES, IE, LU, PT, 2020) (EDF, 2020) (WindEurope, 2020) (Eurelectric, 2021) (MultiPLHY, 2021) (Hydrogen Europe, 2020a). Both models can serve to prove compliance with RED II requirements, and leaving both options open to economic operators allows them to choose the electricity sourcing model or models most fit for their purposes.

Alternatively, the DA could be limited to Model I (PPAs), as proposed by Transport & Environment (Transport & Environment, 2021). This approach may be chosen for legal reasons, as RED II does not mention GOs in the context of this DA while PPAs are mentioned in Recital 90. Rules for GOs, on the other hand, are set out in Article 19. However, such an approach could have severe consequences, which are as follows:

- The RES-E sourcing of RFNBO producers would be entirely bound to the still-illiquid PPA market, making RES-E sourcing more expensive and potentially stalling investments altogether. Also, this market would solely consist of bilateral contracts, which might limit market transparency and prevent the creation of a central market place.
- RFNBO producers would be temporally correlated with one or several specific RES-E producers, limiting asset utilisation. Assuming long-term PPAs are used, there would also be little flexibility to increase production if needed.
- Case 3 would essentially become similar to Case 2, with the major difference being that Case 2 uses a direct private line for RES-E sourcing while Case 3 uses the public grid. Other than this difference, RFNBO producers in both cases would economically and temporally be coupled to specific RES-E assets. This difference means that RFNBO assets, even in Case 3, would not be operated in a way that aids RES system integration.

7. Increasing requirements over time

The requirements of the DA could be designed to phase in rather than be introduced in full effect from the beginning. This concept has been brought up by numerous stakeholders (EDF, 2020; Hydrogen Europe, 2020a; Power to X Alliance, 2020; Global Alliance Powerfuels, 2020; VDMA, 2020).[64] In this section, the project team outlines arguments for and against such a concept, including some general design considerations (Section 7.1) and concrete proposals on how requirements in Case 2 and Case 3 could be phased in gradually (Sections 7.2 and 7.3).

7.1 General considerations

Sustainability requirements for RFNBOs, such as the renewability requirements discussed in this report, need to be balanced against the market ramp-up of RFNBOs, which is a clear political priority across Europe. On one hand, sustainability requirements should not be so strict that they impede replacing fossil fuels with RFNBOs. On the other hand, the absence of strict sustainability criteria could lead to RFNBOs having a worse GHG footprint than fossil fuels, rendering the use of RFNBOs futile since GHG savings are the primary reason to use RFNBOs.

Importantly, the legal feasibility of such a phase-in of requirements would need to be examined. RED II does not explicitly expect it; introducing the concept in the DA would, therefore, require special justification or may be considered out of scope of the DA. Introducing requirements in a gradual two-phase approach with an early softer phase and a later strict phase would achieve a balanced compromise in this trade-off. This approach would have several advantages:

1. The rapid short-term scale-up of RFNBO production (e.g. the Commission's target of 6 GW electrolyser capacity by 2024) (European Commission, 2020) would not be hindered by obligations that are still difficult to fulfil.
2. There would be time for required electricity market products to develop (e.g. RES-E GOs carrying more information or PPAs with new, unsupported assets).
3. RFNBO renewability would be ensured by strict criteria in the second phase once RFNBO production capacities have reached significant scale.

A drawback of this approach is that some negative effects in the first phase would need to be tolerated. For instance, the absence of full additionality requirements in Case 3 in the first phase would lead to RFNBO production partially consuming RES-E that is diverted from existing RES-E consumers. These consumers would likely consume additional non-renewable electricity, potentially leading to increased GHG emissions. Further, it is not clear whether the DA has the power to introduce such a phase-in approach, as mentioned previously. This possibility needs to be examined from a legal perspective.

If phase-specific requirements were introduced over time, some questions on the concrete design would arise. Two of the most fundamental aspects are as followed:

- Determine the point in time at which Phase 1 switches to Phase 2.

[64] (Bellona Europa, 2020) has, in contrast, criticised this concept.

- Apply rules of the two phases to RFNBO production assets installed in Phase 1, given that they also will be operational in Phase 2.

How to determine the phase transition

If requirements are differentiated between two phases, a point in time must be identified when the regulatory framework shifts from the first phase to the second. This point in time should reflect when RFNBO production is no longer a niche technology but is reaching industrial scales and has a considerable effect on the electricity system. A clear transition date should be determined to provide predictability to the market, acknowledging that determining such a date would be arbitrary to some extent.

One option to determine the transition date would be using the Commission's target of 6 GW of electrolyser capacity in the EU as a threshold. Once this is reached, Phase 2 would begin. An advantage of this option is that it explicitly reflects the effect of RFNBO production on the electricity system by using its electrical peak load as a benchmark. The definition does have some significant drawbacks:

There is no official counting of installed electrolyser capacity in the EU yet (e.g. by Eurostat).[65] Some statistics are available (e.g. from the Fuel Cells & Hydrogen Observatory (FCH JU, 2021)). A transparent methodology would need to be developed to establish at which point in time a specific project is counted (e.g. commissioning date or final investment decision).

RFNBOs include technologies other than hydrogen electrolysis (Fischer-Tropsch processes, methanol production, etc). These capacities would have to be reflected as well, making the statistical treatment of the transition point even more complex.

Electrolysers will not just be produced for the transport sector—they will also be produced for industrial consumers. The DA, pursuant to RED II Article 27.3, relates exclusively to the transport sector. This could lead to an effect where electrolyser capacity is rapidly expanded for industrial off-takers, leading to a switch to Phase 2, even though transport fuel production would make up only a small part of the installed capacity.

Once the capacity threshold is reached, there would need to be a grace period for projects in the construction phase. If the phase transition took place immediately upon reaching the threshold, some projects may suddenly be incompliant and become stranded assets.

A simpler option would be to identify the phase transition by a given date (e.g. the end of 2024 in line with the 6 GW target).[66] This would not require new official statistics and would provide planning certainty to the market. A drawback would be that it would not be directly coupled to the existing ramp-up of RFNBO production capacities, creating a risk in two directions:

- If RFNBO capacities grow slower than expected, requirements may become strict at a time when the market has not gained sufficient scale (Hydrogen Europe, 2020a).

[65] The most recent SHARES tool manual states: "In Regulation (EC) No 1099/2008 on energy statistics hydrogen [and synthetic fuels, e.g. RFNBOs] are not accounted for and monitored for its use due to its current statistical insignificance, and thus it does not need to be reported. This approach might change in the future if synthetic fuels of renewable origin are used to a significant scale as transport fuel. […] For the overall RES share, the impact is negligible as the overall use of synthetic fuels of renewable origin in European energy economy is still insignificant."

[66] The exact date would require further analysis. It would need to consider the date at which this regulation is adopted and the lead time of RFNBO plants. If, for instance, the DA was adopted in December 2021, Phase 1 would only last 3 years while the lead time for electrolyzer projects is 2 years.

- If RFNBO capacities grow faster than expected, this could lead to adverse effects. For instance, if large quantities of RFNBO are produced with softer requirements, GHG emissions could be caused and a larger asset fleet than intended would enjoy soft plant-related requirements.
- As the Commission and an increasing number of Member States are announcing quantified targets for RFNBO production, the trajectory of RFNBO capacities is becoming more and more predictable. This facilitates the identification of a suitable date for the phase transition. Alternatively, the transition date could be reviewed at a later point to be postponed, if necessary (Hydrogen Europe, 2020a).

If the requirements discussed in this report were to be applied to other sectors, more considerations would arise. In industry, for example, early use cases will likely replace polluting feedstocks and fuels, such as grey hydrogen, coal, or natural gas, with green hydrogen. These are important pillars towards carbon neutrality, but the ability to pay price premiums in industry is much lower than in the transport sector. The phase transition date may need to be later if industry was included in the requirements discussed in this report.

Application of rules in both phases

When Phase 1 transitions into Phase 2, it needs to be ensured that existing assets do not need to comply with the new, stricter requirements to an extent that creates major difficulties or is even impossible. Production assets installed in Phase 1 should not be granted overly attractive conditions in perpetuity, which could create an unintended race for RFNBO installations in Phase 1. This would create an uneven playing field between Phase 1 and Phase 2 assets with potential windfall profits.

The project team proposes applying the increasing requirements based on whether the requirement relates to the plant itself (i.e. cannot be changed or only with reinvestments) or to the operations of the plant (i.e. can be changed without fundamental physical adaptions of the plant):

- **Plant-related requirements** (e.g. asset location) apply depending on which phase the asset was installed.[67] Otherwise, assets could be rendered incompliant overnight when Phase 2 begins (Hydrogen Europe, 2020a).
- **Operations-related requirements** (e.g. on properties with a kilowatt-hour of electricity consumed) apply depending on which phase the unit of RFNBO was produced. Electricity procurement can be switched to comply with Phase 2 regulations. Otherwise, there would be negative lock-in effects that persist beyond Phase 1 (Bellona Europa, 2020). If RFNBO assets installed during Phase 1 would be able to source RES-E with less requirements over their entire lifetime, this would create windfall profits because they would be able to procure cheaper RES-E than assets installed in Phase 2.

Independent of the application of requirements in Phases 1 and 2, an issue might arise with RFNBO production assets that enter operations before the DA is adopted. There is already a

[67] If the commissioning date was chosen to define this, an RFNBO project might be at risk of shifting into Phase 2 conditions if the construction is delayed for some reason, potentially making to severe difficulties regarding plant-related requirements. The issuing date of the construction permit would be an alternative to mitigate this risk. It would have the drawback, though, that RFNBO producers may aim to receive a disproportionate amount of construction permits in Phase 1 and implement the projects over a much longer timeframe than usual to benefit from Phase 1's plant-related requirements.

pipeline of projects in Europe, which should not be rendered incompliant in case they happen to not fulfil the plant-related requirements of the DA.

Recommendation: Introducing requirements in a gradual two-phase approach is a suitable mechanism to compromise between RFNBO market scale-up and sustainability. The transition between the two phases should be determined by a year (e.g. 2024) to ensure predictability for the market. Rules in both phases should be applied in a way that does not create stranded assets by requiring retroactive compliance where it is difficult or impossible (e.g. plant-related requirements like asset location).

7.2 Potential concept for Case 2

As discussed in Section 5, the envisaged Case 2 methodology incorporates two items—commissioning date synchronisation and smart metering granularity—that, depending on the strictness of their design in the DA, could inhibit the market uptake of RFNBO capacities. In both cases, an approach incorporating increasing requirements over time could theoretically alleviate the burden in the first phase until market players are experienced enough to meet more stringent requirements that align with RED II. However, given that the requirements for the methodology in Case 2 are already described quite explicitly in RED II, the validity of such an approach seems to be highly questionable from a legal point of view. The following elaboration of a potential concept should, thus, only be considered after its legal feasibility has been confirmed.

The first requirement, "timing of the RES installation commission," demands that the RFNBO installation comes into operation before or at the same time as the RES-E installation. The project team argues in Section 5.2.1 that the commissioning date of the installation is the most fitting proxy to fulfil this requirement. However, there is a degree of flexibility regarding the exact definition of RED II's at-the-same-time provision. The project team considers a quarter of a year to be the duration of choice to balance between a strict interpretation of RED and practicability for RFNBO producers. In practice, this balance means that as long as the commissioning date of the RFNBO installation is no later than 3 months after the RES-E installation's, the RFNBO producer is eligible for Case 2 methodology. To alleviate the risk related to the timing of the commissioning date during the market uptake of RFNBO, it is conceivable to extend this duration to 1 year in the first phase. While the RFNBO market is not yet mature, experiences with lead times of industrial-scale RFNBO installations are still limited and delays are more likely, making an extension during the first phase beneficial and justifiable.

The timing of the renewable energy installation commissioning is a plant-related requirement, as defined in Section 7.1. As such, all projects that obtain their construction permit in the first phase would have an increased safety margin regarding the construction duration of their plant to remain eligible for the methodology of Case 2. Projects approved in the second phase would have to comply with the regular interval for checking commissioning date simultaneity. Two potential risks accompany this concept:

- First, whether extending the interval is actually compatible with RED II remains to be verified.
- Second, the longer this interval, the more likely it becomes that RFNBO installations are built with additional demand that is not met by additionally deployed RES-E. It becomes more likely that the investment decision for an RFNBO installation is based on the planned deployment of a RES-E installation that would have been built regardless of the former.

The second requirement demands that the RFNBO installation is exclusively supplied via direct connection and thus constitutes an operations-related requirement. In Section 5.2.1, the project team argued that supply and demand smart metering with a temporal granularity of 15 minutes is the most suited fulfilment option. However, certain stakeholders considered this granularity as a potential burden that could inhibit the market uptake of RFNBOs. It would be conceivable to decrease the required granularity during the market uptake phase. However, the project team advises against adopting an increasing requirements over time approach in this case for two reasons:

- A granularity lower than the technical measurement standard might be incompatible with the wording of the RED II, which requires that the electricity be sourced exclusively via the direct connection.
- Moreover, under the methodological framework the project team proposes, RFNBO producers are not strictly required to set their consumption to the output of the connected renewable energy installation. Instead, they have the flexibility to fall back to Case 3 methodology to claim renewability for those electricity quantities that exceed the generation of the connected renewable energy installation. Lowering the granularity in the first phase does not improve the operational flexibility of the RFNBO plant in practice.

Recommendation: The project team recommends introducing the requirement to relatively time the commissioning dates of RFNBO and RES-E installations in a gradual two-phase approach in order to provide producers a safety margin during the market uptake phase. However, the legal feasibility of such an approach has not been confirmed.

7.3 Potential concept for Case 3

Since RED II leaves more room for the DA in defining Case 3 than it does for Case 2, increasing requirements may be more likely to be legally feasible here. Still, the legal feasibility of this approach has not been assessed in this project and would need to be confirmed. Case 3 contains some requirements that can be introduced in full effect from the beginning:

RES-E sourcing via generic GOs or PPAs is common practice for corporate RES-E sourcing and would not disproportionately burden producers. Also, the required minimum to fulfil the RED II requirement is that electricity for Case 3 must come “exclusively from renewable sources.”

Geographical correlation can be determined through bidding zones as a default from the beginning because this leaves enough flexibility for RFNBO producers (see Section 6.4.4). Assuming there will be bidding zone splits in the future, this requirement may become stricter over time. Member States might also choose to limit RFNBO production to suitable areas in any phase (see Section 6.4.4.3), which would also lead to stricter requirements even if geographical correlation is not part of a two-phase approach set out on the EU level.

Other requirements of Case 3 should be phased in over time to avoid significant stalling of RFNBO market development in the first implementation years of RED II. As for **temporal correlation** (see Section 6.4.3), the general mechanism of correlation with the contracted RES-E asset or correlation with RES-E infeed at the system level can be implemented from the beginning. The project team recommends the following in light of this information:

- Temporal correlation with specific RES-E assets under a PPA (see Section 6.4.3.1) needs to be based on a time period within which the generation and consumption volumes need to match. The project team recommends this period should be 1 hour in Phase 2, but it could be extended to 1 day in Phase 1 to give early investors more operational flexibility.

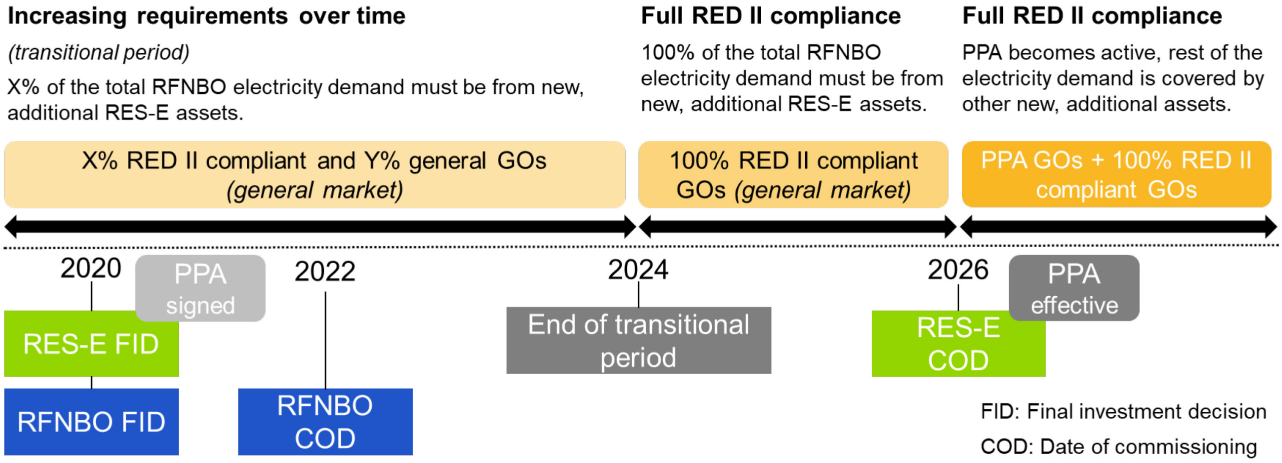
- For system-level correlation (see Section 6.4.3.4), the project team recommends looking at the system-level RES-E share at intervals of 1 hour. Extending this to full days in Phase 1 would reduce volatility for RFNBO producers.
- Gradually introducing temporal correlation would ease the operation of the first industrial-scale RFNBO production facilities in the coming years. Once operators are more experienced with these technologies (i.e. Phase 2 begins), stricter intraday temporal correlation can be applied (SolarPower Europe, 2021).

As for **deployment additionality** (see Section 6.4.1), a potentially major risk comes from the unavailability of new, unsubsidised RES-E assets (or eligible old, formerly subsidised assets) during the first years of RED II's implementation. This unavailability could significantly slow down the development of the RFNBO market, particularly in certain geographies. This issue could, and in our opinion should, be addressed by increasing requirements over time—for instance, requiring that only a given percentage of the total electricity demand is sourced from additional RES-E assets in the first phase.[68] Alternatively, in case such an approach is not legally feasible, one could introduce a grace period (e.g. until 2024) before the requirements apply (SolarPower Europe, 2021).

Error! Reference source not found. outlines an illustrative example of how these risks could be addressed so they do not unduely burden RFNBO operators. In the example, a PPA between RES-E assets and an RFNBO operator is signed in year 0. Due to the different lead times, the RFNBO comes into operation before the contracted asset. In that period, it has to source RES-E from the RED II-compliant GO market. In the first period, until the end of 2024, it only partially sources from RED II-compliant markets (a given percentage), in 2025 it sources from this market fully, and from 2026 (after the RES-E asset becomes operational) onwards, the electricity is sourced from the contracted RES-E asset (via a PPA) and RED II-compliant GOs. All of the years used in the example are illustrative.

[68] Some stakeholders have argued there should be no additionality requirement at all in Phase 1 (Hydrogen Europe, 2020a), while others have argued there should be no alleviation of additionality requirements in Phase 1 (Bellona Europa, 2020).

Figure 16. Illustrative example of RES-E sourcing under deployment additionality



Some Member States have proposed that additionality should be considered fulfilled automatically in countries with high RES-E shares (AT, DK, ES, IE, LU, PT, 2020). However, this is already covered by the way the RED II designed the three cases. Once the electricity generation in a country is renewable to an extent that it has significantly lowered the grid emission coefficient, RFNBO producers can use Case 1, which does not impose any additionality requirements.

Recommendation: The project team recommends that the granularity of temporal correlation could be less demanding in the first phase (i.e. evaluating correlation based on a full day's consumption instead of each individual hour), which would ease the operation of the first industrial-scale RFNBO production facilities in the coming years. Additionality could be required only for a given percentage of electricity consumption to allow for the development of liquid markets for RES-E from new and unsubsidised assets before all consumption must be additional.

8. Case studies

This section presents six case studies that illustrate how this task's proposed methodology can be applied in practice. All projects and numbers in the case studies are purely fictional. The case studies cover a broad range of potential settings:

- Case study 1: Kerosene production with grid electricity in Norway (Case 1)
- Case study 2: Hydrogen production with grid electricity in Austria (Case 1)
- Case study 3: Hydrogen production with colocated solar PV in Spain (Case 2)
- Case study 4: Kerosene production with colocated PV and wind in Saudi Arabia (Case 2)
- Case study 5: Kerosene production with RES-E GOs in Poland (Case 3)
- Case study 6: Hydrogen production with a contracted offshore wind farm in the Netherlands (Case 3)

8.1 Case study 1: Kerosene production with grid electricity in Norway (Case 1)

8.1.1 Introduction

This hypothetical case study represents the standard application of Case 1 for an RFNBO producer in a country with high renewable share (greater than 95%). At such a location, an RFNBO producer faces few obstacles to develop a Case 1 production facility. Table 5 summarises the key assumptions underlying this case study.

Table 6. Main parameters of case study 1

Main characteristics	Standard case
Cases applied by RFNBO producer	Case 1
Type of RFNBO installation	200 MW Alkaline Electrolysis and subsequent Fischer-Tropsch synthesis
Final RFNBO product(s)	Kerosene
Owner or operator of RFNBO installation	Oil & gas company
Location of RFNBO installation	Norway
Electricity procurement model, technology type(s) of RES-E sources	Sourcing through wholesale market
Connection between RFNBO and RES-E installation(s)	Not applicable (RES-E is not sourced from specific assets)

This case study assesses an exemplary RFNBO production by a Norwegian oil & gas company that wishes to diversify its business and sees renewable fuels as a way to achieve this goal. Considering the high share of renewable electricity in the Norwegian power supply, setting up a Case 1 RFNBO production facility could be a business case. The producer decides to set up a production facility for a high energy density fuel, such as kerosene, that stands apart from green hydrogen plants emerging in other countries with lower RES-E shares. Nevertheless, kerosene production first requires an electrolysis unit to produce hydrogen, which is then further processed to kerosene using CO_2 sourced from local industries.

At the core of the plant is a 200 MW_{el} PEM electrolysis unit, which is assumed to run for 8,000 hours per year. This corresponds to an electricity demand of 1.6 TWh or 1.12% of the renewable electricity generated in Norway (according to SHARES results on 2018). At an efficiency of 65% and 33.33 MWh/tonne (120 MJ/kg) for hydrogen LHV, a total of 31.2 kt hydrogen will be produced by the plant annually.

Downstream of the electrolysis unit for hydrogen production, the producer installs a Fischer-Tropsch unit to synthesise kerosene.[69] This requires CO_2 feedstock, which is then used with the hydrogen to generate the synthesis gas and finally, the kerosene. Approximately 360 MWh/kt CO_2 are required. Only a part of the hydrogen previously generated ends up in the kerosene, and a substantial share is converted back to water. In total, the plant will produce roughly 52 kt kerosene annually. The kerosene production will use 1.15% of RES-E generated in Norway (or 15% of the electricity exports; 1.65 TWh), the electrolysis requiring the largest share of the electricity.

If all carbon required to synthesise 52 kt of kerosene is supplied through CO_2, approximately 250 kt CO_2 is required. Commonly, the synthesis is not fully efficient (the Task 1 report gives a usage efficiency of 65%), so more than the purely stochiometric value is required. To supply the CO_2, the producer sets up a contract with industry in the vicinity of this plant, in this case with companies in the cement or chemical industry. This has advantages over DAC as it requires less energy and implies lower costs. Additionally, the technology is more mature, which allows for a faster project development. In Norway, emissions from Industrial Process and Product Use (IPPU) sum up to 7.5 Mt CO_2 (only CO_2) in 2018.[70] The producer could source CO_2 from a mixture of emissions from cement production (730 kt CO_2 in 2018) and titanium dioxide production (250 kt CO_2 in 2018). These are at least partially located in the vicinity of the Oslo fjord area,[71] making the area ideal to reduce CO_2 transport costs and those of the final product to a large airport.

8.1.2 Requirements and evidence provision during RFNBO production

The RFNBO producer has chosen Case 1 production for reasons of accounting simplicity. Norway presents ideal conditions to apply Case 1 RFNBO production. Applying Case 1 methodolgoy comes with limited obligation on the producer to prove the renewable energy content of the RFNBO product, in this case, the kerosene. The producer only needs to refer to the RES-E share in Norway as given by the SHARES results of Eurostat 2 years before the year in question. Norway relies heavily on hydro power. In past years, more renewable electricity was generated in Norway than the country's overall electricity demand, and the RES-E share ,according to Eurostat, was above 100% (with an average of 106% between 2010 and 2019, above 100% since 2011). From the perspective of the producer, there is little risk in the assumption that Norway will switch to fossil-powered electricity generation in the future. By applying the RES-E share given by Eurostat, the kerosene produced will count as fully renewable, credited with 100% renewable energy content. For administrators, the

[69] Kerosene is commonly a mixture of hydrocarbons. The project team adopts an LHV of 43 MJ/kg.
[70] United Nations Climate Change. "Greenhouse Gas Inventory Data - Detailed data by Party." **https://di.unfccc.int/detailed_data_by_party**.
[71] Location of cement production sites is accessible from: CemNet. "Cement Plants located in Norway." **https://www.cemnet.com/global-cement-report/country/norway**; titanium dioxide I is produced in Fredrikstad (Kronos. "About Us." **https://kronosecochem.com/en/about-us/**).

evidence is as simple as for the producer: Being able to refer to the SHARES results of Eurostat. RFNBO produced in Norway will also qualify as fully renewable.

The large share of Norwegian IPPU emissions used by the plant (3.4%) gives the project substantial publicity. All requirements and technology are likely to be discussed even by general media. This brings up voices stating that the production is not sustainable and just a new business of a well-established oil & gas company that profits by joining forces with a likewise established utility while climate benefits are limited. Other voices hail this as an innovative lighthouse project of Norwegian technology, paving the way to diversify the business of a company otherwise focussed on fossil resource extraction.

An energy intensive large-scale production of kerosene, as described here, would lower the electricity available for export to neighbouring grids by the amount consumed in RFNBO production (1.65 TWh). This loss of availability may lead to an increase in total emissions, depending on the alternative use of the renewable electricity.

A separate DA is in development that deals with questions surrounding GHG emission savings and RFNBOs. The project team assesses this aspect here, however, without any prejudice to the DA itself. The project team assumes that the export of electricity from Norway happens mainly in times of shortages in neighbouring grids at times of peak demand. Missing imports from Norway (as would occur in the case of the kerosene production considered here) would likely lead to an increase in emissions, as peak load power plants are often fuelled by natural gas. Assuming that the renewable electricity generated in Norway is replaced by natural gas-fired power plants (with an emission factor of 56.1 t CO_2/TJ[72]) in the countries importing the electricity in the alternative use case, the electricity generated would lead to emissions of 332.5 kt CO_2. Without the project, Norwegian renewable electricity avoids the emissions from peak electricity generation in other countries (332.5 kt CO_2 in the case of pure natural gas combustion). If used in kerosene production, Norwegian renewable electricity avoids the CO_2 emissions sequestered for use in the kerosene production (estimated at 250 kt CO_2), foregoing emission savings of approximately 82.5 kt CO_2, or 25% of the savings achieved in the alternative use case. Even if not necessarily counted towards the RFNBO (DA pending), this project increases total CO_2 emissions.

8.1.3 Summary and learnings from this case study

By design, Case 1 is simple in implementation and administration. Norway's RFNBO production will qualify as fully renewable given the high shares of hydro power in the country, which currently exceeds the inland consumption. The RFNBO would be considered fully renewable as it would be produced in a country with a fully renewable electricity supply.

The project outlined above would consume a substantial share of the renewable electricity generated in Norway, reducing electricity exports by 15%, which will likely lead to an increase in total emissions if neighbouring grids are not fully decarbonised. Under the assumption that renewable electricity from Norway otherwise reduces peak load generation from gas-fired power plants, the production and use of kerosene from this project increases emissions by approximately 82.5 kt CO_2 annually.

[72] COMMISSION DELEGATED REGULATION (EU) 2018/2066 of 19 December 2018, annex VI

8.2 Case study 2: Hydrogen production with grid electricity in Austria (Case 1)

8.2.1 Introduction

This fictitious case study examines an RFNBO producer in a country with lower, but still high, renewable shares, applying Case 1 of RFNBO production. Table 6 summarises the case study's key assumptions.

Table 7. Main parameters of case study 2

Main characteristics	Borderline case
Cases applied by RFNBO producer	Case 1
Type of RFNBO installation	PEM electrolysis, 200 MW
Final RFNBO product(s)	Hydrogen
Owner or operator of RFNBO installation	Large utility company
Location of RFNBO installation	Austria
Electricity procurement model, technology type(s) of RES-E sources	Sourcing through wholesale market
Connection between RFNBO and RES-E installation(s)	Not applicable (RES-E is not sourced from specific assets)

This case study assesses one case of RFNBO production by an Austrian utility, which wishes to make use of its substantial renewable energy plants to supply a new group of customers and diversify its business. Considering the relatively high share of renewable electricity in the Austrian power supply, setting up a Case 1 RFNBO production facility could be a business case. The producer decides to set up a production facility for hydrogen, which is most versatile in its use.

The plant mainly consists of a 200 MW_{el} electrolysis plant. Assuming this runs for 8,000 hours per year, the production corresponds to an electricity demand of 1.6 TWh, or 3.0% of renewable electricity generated in Austria (according to SHARES results on 2018). At an efficiency of 65% and 33.33 MWh/tonne for hydrogen LHV, a total of 31.2 kt hydrogen will be produced by the plant.

8.2.2 Requirements and evidence provision during RFNBO production

The hydrogen producer has chosen Case 1 production for accounting simplicity. Austria presents good conditions to apply Case 1 RFNBO production. This case comes with limited obligation on the producer to prove the renewable energy content of the RFNBO product (hydrogen in this case study). The producer only needs to refer to the RES-E share in Austria as given by SHARES results of Eurostat 2 years before the year in question. Austria relies heavily on hydro power (dammed and run-of-the-river, covering 56% in 2018), with increasing shares covered by solar PV (2% in 2018), wind energy (9% in 2018), and biofuels (5% in 2018). In the past years, the RES-E share, according to Eurostat, was higher than 70% (with an average of 70% between 2010 and 2019 and above 70% since 2014). From the producer perspective, there is little risk in the assumption that Austria will lower this share in the coming years.

The renewable energy content of the RFNBO product will be determined from this share. In 2021, the producers would apply the 2019 RES-E share to determine the share of renewable energy in the hydrogen (75.1%). For administrators, the evidence is as simple as for the producer, being able to refer to the SHARES results of Eurostat.

However, in the case of Austria, the second criterion of GHG emission savings becomes relevant. Article 25.5 specifies that at least 70% savings from the use of RFNBOs must be achieved. A separate DA is in development that deals with methodologies for GHG emission savings and RFNBOs. The following analysis makes implicit assumptions on these methodologies for illustration purposes without any prejudice to the DA itself.

In the case of Austria, electricity consumption (and so hydrogen production) comes with certain emissions that depend on the grid emission factor. (European Environment Agency, 2020) gives these statistics, with the last value of average grid emissions at 28.9 gCO_2/MJ in 2017. As the renewable share increases (and has increased since 2017), this factor will decrease. The project team adopts it for reference in the following paragraphs of this case study.

With a fossil comparator of 94 gCO_2/MJ (as set out for biofuels in Annex V C.19, only an indicative reference) and 70% savings required by RED II, the value achieved by the hydrogen production needs to undercut a value of 28.9 gCO_2/MJ. In the case evaluated here, the emissions associated with the energy content of the hydrogen would amount to 44.5 gCO_2/MJ.[73] In 2017, the hydrogen produced by this plant in Austria would not have qualified as renewable. If past trends for Austria continue,[74] the required value of 18.3 gCO_2/MJ for the grid emission factor will be achieved in 2027. If a better efficiency of the electrolysis is achieved by technological improvements, the grid emission factor can be higher, and RFNBO production would become possible earlier. This simple forecast builds on a linear trend. The hydrogen producer will need to assess RES-E expansion plans in detail to decide when Case 1 production is realistic. Likely, the utility will wait several years to invest in this plant or decide to apply one of the other cases of RFNBO production until Case 1 becomes viable in Austria. The details of GHG emission savings methodology for RFNBO production will be clarified in a respective DA.

8.2.3 Summary and learnings from this case study

By design, Case 1 is simple in implementation and administration. RFNBO produced in Austria may qualify as renewable in the coming years, depending on the GHG emission savings criteria laid down in the respective DA. If the grid emission factor is taken as the sole indicator, an RFNBO production making use of Case 1 would become possible in Austria around the mid-2020s. Until then, the producer would need to apply one of the other cases.

8.3 Case study 3: Hydrogen production with colocated solar PV in Spain (Case 2)

8.3.1 Introduction

This case study is based on a hypothetical case of a Spanish oil & gas company that intends to enter the hydrogen business and to produce green hydrogen. The company's electrolysis facility is supplied by a nearby PV park that is linked through direct connection. The PV park

[73] Considering the latest grid emission factor available (2017) and an electrolyser efficiency of 65%.

[74] Assuming a linear best fit to historic values since 1990 as given by EEA, which are currently available until 2017.

is additionally connected to the public grid and feeds excess electricity that is not consumed by the hydrogen producer into the grid. The hydrogen producer relies on the Case 2 methodology proposed in this report to prove the renewable origin of the electricity it consumes in the electrolysis process.

8.3.1.1 Purpose of this case study in the overall context of this project

The objective of this case study is to provide a cohesive storyline detailing why a green hydrogen producer could intend to rely solely on the project team's proposed Case 2 methodology, even though they dispose of a grid connection and could theoretically fall back on Case 3 methodology. As this opportunity remains, the project team refers to case study 6, where renewable electricity sourcing from the wholesale market is discussed in detail. Here, the project team elaborates on the direct connection aspect and discusses how the hydrogen producer provides the required evidence about the origin of the RES-E. The project team also confronts the potential implications of this evidence provision on the business case.

8.3.1.2 Type of RFNBO producer and techno-economic background of the production case

In **2021**, given its national connections, the future green hydrogen producer in this case gains knowledge of a large-scale PV power plant project that is still in the conception phase. They decide to approach the project developer and propose constructing a hydrogen-production facility in direct proximity to the PV plant. Furthermore, the producer suggests linking installations via their own electricity line and setting up a PPA that provides a long-term planning horizon for both parties. Table 7 summarises the general project data.

Table 8. Main parameters of case study 3

Main characteristics	Standard case
Brief description	A large-scale RFNBO installation is connected via direct connection to a PV power plant and to the grid.
Cases applied by RFNBO producer	Mainly Case 2 with grey electricity via the grid and Case 3 as an opportunity
Type of RFNBO installation	PEM electrolysis, 10 MW
Final RFNBO product(s)	Hydrogen, to be supplied to a nearby refinery
Owner or operator of RFNBO installation	National oil & gas company
Location of RFNBO installation	Spain
Electricity procurement model, technology type(s) of RES-E sources	PPA with PV power plant. Additionally, some electricity sourcing via wholesale market to increase full load hours. Excess electricity is sold to the grid.
Connection between RFNBO and RES-E installation(s)	Electrolyser and solar plant are colocated and connected via direct connection.

Given the novelty of the business and current uncertainty about future market conditions, the hydrogen project developer values a project set up that reduces project risks and administrative burden. They wish to procure RES-E from a single RE producer (i.e. said developer that intends to build a 100 MW PV park). Given the intermittency of the renewable electricity supply, it is critical to keep the electrolyser capacity well below the nominal power of the PV plant to obtain considerable full load hours. The hydrogen producer opts for an electrolyser with a capacity scaled in relation to the PV plants. A 10 MW PEM electrolyser will be installed, providing two key advantages for the company:

1. PEM electrolysis is technologically mature and has been commercially available for over 2 decades.

2. It provides flexibility, partially allowing the intermittencies in the PV plant's electricity production to be followed. For example, the electrolyser could ramp up with the sunrise in the morning hours.

That said, some intermittencies, such as power drops due to shaded panels, might occur at time scales that are too short for economic supply following. In those times, grey electricity can be sourced from the grid to buffer the fluctuations in power supplied by the PV plant.

8.3.2 Requirements and evidence provision before the start of RFNBO production

8.3.2.1 Requirements to be fulfilled

In **2021,** the hydrogen producer knows that to be eligible to claim renewability for its consumed electricity via Case 2, two requirements have to be met before it starts hydrogen production:

- It must prove that its hydrogen production is linked via direct connection to an RE installation (e.g. the PV plant).
- It must prove that the linked PV plant did not start its commercial operation before the electrolyser. The start of qits commercial operation must be qualifiable as at the same time or later.

***8.3.2.2 Efforts and costs for RFNBO** producer to provide evidence*

The business models of the PV plant operator and the hydrogen producer are interlinked. The hydrogen obtains RES-E at a predetermined price while the RE producer gains a long-term purchase insurance. This arrangement must be contractualised. Both parties agree to formalise their relationship via a PPA, starting with their commissioning dates expected for May 2024. The hydrogen producers commit to buying all the PV plant's electricity generation in a bandwidth from 500 kW up to 10 MW. The lower end corresponds to the electrolysers minimal load requirement of 5% while the upper limit corresponds to its maximum capacity. The price is fixed at 20 EUR/MWh. Given the strict timing requirement in RED II, the PPA also incorporates a provision determining contractual penalties in case of construction delays, and both parties commit to pay the difference between market and PPA price.

From **2022-2024**, the future hydrogen producer uses this time for detailed planning and constructing the electrolyser. The hydrogen producer has a time buffer before tackling the construction phase due to shorter lead times compared to the PV plant. Of course, the plant must dispose of an internet connection to enable the transfer of consumption data to the certification body. During this period, the hydrogen producer also needs to construct the direct connection line between electrolyser and the PV plant.

The construction of the hydrogen electrolyser and PV plant needs to be coordinated to enable a synchronised start of commercial operation. This coordination effort entails some minor personnel costs. It is unlikely that this has any relevant impact on the calculation of the financial viability of the project.

Another cost element that must be borne by the hydrogen producer is for setting up the direct connection line. However, as the electrolyser is built in direct proximity to the PV plant, the length of the direct connection does not have to be longer than the electricity cable that would otherwise be required for the connection to the public grid. Those costs cannot be considered as compliance costs.

In **May 2024**, weeks before the end of the construction period, a renewal of the coronavirus pandemic leads to a shortage of critical construction personnel. Consequently, the commissioning date of the electrolyser is delayed by 2 months. This delay might pose an enormous problem for the hydrogen producer. Assuming that the timing requirement in RED II regarding the start of at-the-same-time operation was in danger of not being met, this would lead to the following dilemma:

1. The PV producer agrees to delay its commissioning date so both facilities still fulfil the RED requirement. Both installations would then start their operation in July 2024. However, this option would lead to considerable costs in foregone revenues on the side of the PV producer. Given that it could already be fully commissioned, the PV plant loses revenues from selling its electricity on the wholesale market during those 2 months. The resulting opportunity costs would have to be borne as a contractual penalty by the hydrogen producer because they are responsible for the delay. Those costs would amount to roughly 15% of the hydrogen producer's CAPEX.
2. Alternatively, the PV producer already starts its commercial operation and both facilities actually do not meet the RED II timing requirement. Claiming 100% RES-E via Case 2 methodology is no longer possible. Depending on whether the definition of newness has been broadened (see Section 6.1.2), sourcing from the PV plant might still be possible via Case 3 methodology. Otherwise, the hydrogen producer has to rely on RES-E from the wholesale market and the respective trade of eligible GOs (see Section 8.5).

However, it is fortunate for the hydrogen producer that the project team's Case 2 methodology plans for a period for commissioning at the same time at a total of 3 months. This effectively dissolves the dilemma. With a delay of 2 months but still counting as at the same time, the electrolyser is fully commissioned in July 2024. The producer bears the costs for the revenue difference between the price fixed in the PPA and the wholesale price the PV plant operator obtains. Assuming market values for solar at the wholesale market at three-quarters of the price fixed in the PPA, this amounts to 1% of the electrolysers CAPEX.

8.3.2.3 Efforts for auditors/administrations to examine evidence

The certification body simply checks the commission dates of the PV plant and of the electrolyser and confirms both installations are commissioned at the same time.

8.3.2.4 System-level impacts

The additional electricity demand induced by the electrolyser can only be met with additional renewable electricity if the PV project is not carried out without the contract with the hydrogen producer. Given the small size of the electrolyser compared to the PV plant, the electrolyser consumes roughly 20% of the PV plant's yearly production. The PV producer must sell most its production (e.g. 80% of its electricity generation) to another off-taker or to the spot market. This makes it unlikely that the PV plant's business case is entirely dependent on the connection of the electrolyser and thus raises questions about the additionality.

8.3.3 Requirements and evidence provision during RFNBO production

8.3.3.1 Requirements to be fulfilled

From **July 2024 onwards,** the hydrogen producer is aware that to be eligible to claim renewability for its consumed electricity via Case 2, one requirement must be met during hydrogen production. The consumption for which the RFNBO producer claims a 100% RES-E share via Case 2 can at no time exceed the infeed of the connected RES installation.

8.3.3.2 Efforts and costs for the RFNBO producer to provide evidence

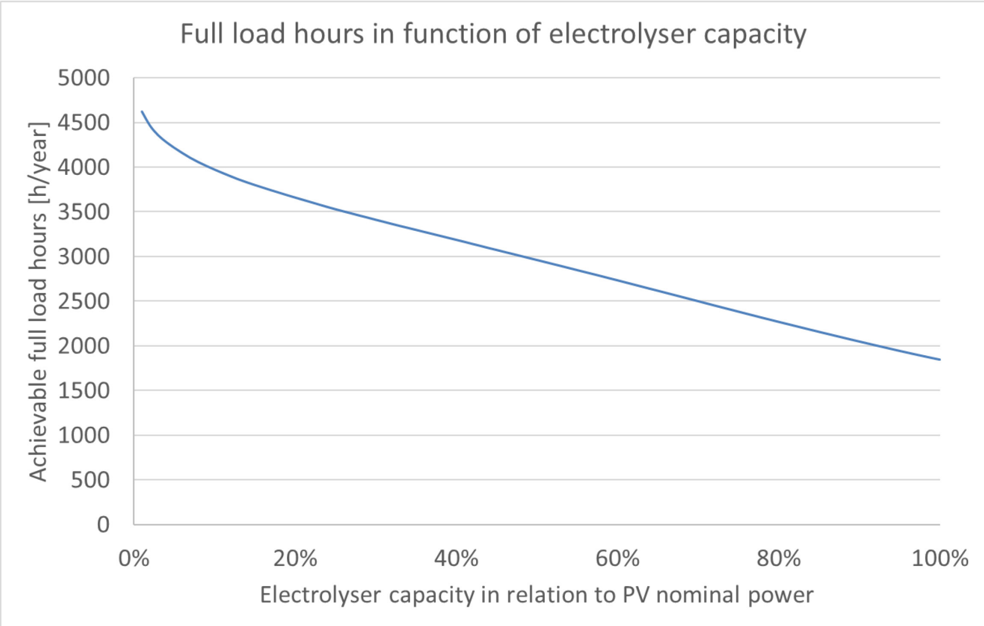
Providing evidence that the requirements are met entails little direct effort for the hydrogen producer. The hydrogen producer and the PV plant operator have to meter their electricity consumption and generation and forward it digitally to the RFNBO certification body. The hydrogen producer claims renewability for its electricity consumption where the corresponding feed-in from the PV plant coincides. Metering and forwarding this data to the certification body does not induce any quantifiable, let alone considerable, costs for the hydrogen producer.

While there are no relevant costs tied to the evidence provision, the decision to procure RES-E exclusively from the PV park comes with potentially high indirect costs. The project team considers these costs indirect because the hydrogen producer does not have to bear them. However, opting for the more complex business case, such as described in the case studies for Case 3, might represent a better opportunity and lead to a more profitable outcome.

First, the electrolyser capacity must be undersized compared to the PV plant to enable significant full load hours. Figure 17 shows the relation between the size of the electrolyser compared to the nominal power of the PV park and the resulting full load hours. To reach more than 3,500 full load hours, the electrolyser needs to be at least 5 times smaller than the PV plant. The hydrogen producer in this case study wanted to achieve at least 4,000 full load hours a year and had to build an electrolyser that is 10 times smaller than the PV plant. This implies that all electricity generation exceeding 10 MW cannot be consumed by the electrolyser.

The second cost element relates to the intermittencies of the PV plant below the electrolyser's maximum capacity. In 1,000 hours of the year, even with an electrolyser 10 times smaller than the PV plant, the electrolyser can source less than 10 MW of power from the PV plant. In those hours, the hydrogen producer has the option to either follow the intermittency and run its electrolyser only at partial load or to source additional electricity (renewable or grey) from the grid. If this alternative is financially advantageous, not taking it constitutes a missed opportunity and lost cost. This point also holds for those 3,500 hours where the PV plant does not generate any power because the sun is not shining.

Figure 17: Full load hours of an electrolyser depending on capacity relative to connected PV park.



Source: TU Wien

8.3.3.3 Efforts for auditors/administrations to examine evidence

The certification body digitally obtains the consumption and generation time-series data of both the electrolyser and the PV plant. It then performs an automatised check if the time-series data overlap. The auditors also check whether there is a contractual relation between the hydrogen producer and the PV plant operator. It then confirms the hydrogen producer's claims of 100% RES-E solely for those hours where its consumption does not exceed the PV plant's generation.

8.3.3.4 System-level impacts

The system-level impact of the hydrogen producer's standard operation is limited. Due to its small size compared to the PV plant, the electrolyser runs at full power most hours when the sun is shining. It can run at full capacity for 3,500 hours of the year by sourcing the electricity from the PV plant. Given the contractual relation and the fixed electricity price, it is unlikely that the hydrogen producer will adapt its production in those hours based on the circumstances in the overall grid. Theoretically, however, it could shed load and resell the electricity on the intraday spot market or the balancing energy markets. On the other side, the PV plant only provides 4,000 full load hours, implying that the electrolyser is idle more than 50% of the year unless it sources additional electricity from the grid. In times of low electricity prices, hydrogen producer might decide to source grey electricity from the grid and produce grey hydrogen.

8.3.4 Summary and learnings from this case study

This case study exemplifies how a hydrogen producer can prove that they source RES-E from a PV plant linked via direct connection. The direct efforts and costs of the required evidence provision are limited. The project team's methodology provides some time buffer, reducing financial risks due to delays in the construction time of the electrolyser. During the production process, evidence provision is facilitated by an automatised data transfer, enabling the producer to claim 100% RES-E without having to carry out dedicated actions. Uncertainty about potential opportunity costs of exclusively sourcing RES-E from a single RE producer remains, even more so as the hydrogen producer disposes of a grid connection and theoretically is able to source electricity from the grid. This methodology will only gain relevance if fulfilling the methodology of Case 3 is difficult due to an illiquid PPA market, for example.

8.4 Case study 4: Kerosene production with colocated PV and wind in Saudi Arabia (Case 2)

8.4.1 Introduction

This case study is based on a hypothetical case of a multinational oil & gas company that intends to produce RFNBOs on a massive scale. Due to the enormous RES-E demand required, the company decides to activate large, untapped RES-E potentials in Saudi Arabia and to set up a gigantic off-grid industrial complex. This complex is constituted of a VPP consisting of a PV plant, a wind park, and a battery storage facility to buffer the intermittency of the renewable installations. The VPP feeds an electrolyser and, subsequently, a Fischer-Tropsch plant to produce green kerosene for the world market. The entire complex is isolated from the Saudi Arabian public grid, enabling the kerosene producer to use Case 2 methodology to claim 100% RES-E.

The objective of this case study is to illustrate why a green kerosene producer could opt to build a production facility entirely off-grid and how they can actually proceed to claim 100% RES-E. This case might be of interest for RFNBO producers because it demands the lowest requirements in terms of evidence provision until the entire country qualifies for Case 1.

In **2022,** Some larger countries decided to implement an ambitious quota requirement for RFNBOs in the transport sector from around 2030 on. This results in a massive increase in the demand for synthetic carbon-neutral fuels. Easily accessible renewable potentials are already getting scarcer in proximity of the consumption centres. However, abundant renewable potentials remain in remote off-grid locations.

A multinational oil & gas company decides to massively invest into its kerosene production capacities and to source RES-E from self-built renewable electricity plants in one of those off-grid sites. Its objective is to gain an edge over its competitors via the cheapest possible synthetic fuel production. It locates a territory with suitable conditions for wind and solar plants near the shoreline of the Red Sea. However, establishing a grid connection to the Saudi Arabian public grid to balance the intermittent RES-E generation would be expensive and entail complex processes with national utilities and regulators. The company decides to set-up an entire VPP to feed its electrolysers. To limit the curtailment of renewable electricity, electrical storage facilities are built to balance the volatile RES-E generation. Moreover, the project incorporates a fuel pipeline to the closest sea terminal to export the kerosene, a DAC plant to supply climate-neutral carbon, and a desalination plant to obtain the required freshwater feedstock.

The kerosene producer in this case study is special because they operate the electrolyser, the Fischer-Tropsch plant, the RES-E installations, the storage facilities, and the direct connection electricity lines. This set-up represents an entire electricity system based on intermittent renewables that must be built from scratch, making it an extremely challenging project. With an investment volume of well over 500 million EUR, part of the activities might have to be subcontracted—for instance, the freshwater provision or the DAC installation. Table 8 summarises the general project data.

Table 9. Main parameters of case study 4

Main characteristics	Borderline case
Brief description	An off-grid RFNBO production facility with dedicated PV and wind power supply
Cases applied by RFNBO producer	Exclusively Case 2
Type of RFNBO installation	200 MW ALK electrolysis and subsequent Fischer-Tropsch synthesis
Final RFNBO product(s)	Kerosene
Owner or operator of RFNBO installation	Multinational oil & gas company
Location of RFNBO installation	Saudi Arabia
Electricity procurement model, technology type(s) of RES-E sources	Electrolyser and renewable energy installations belong to the same company
Connection between RFNBO and RES-E installation(s)	Electrolyser and RES-E plants are colocated and connected via direct connection

To limit the final costs per litre of produced kerosene, the company aims to implement economies of scale, explaining the ambitious size of the project. As a result, they decide to opt for a 200 MW ALK electrolyser. The ALK electrolyser is considered the most technologically mature electrolysis process, presents the lowest CAPEX, and has already been implemented in project dimensions of up to 200 MW. The produced hydrogen must be further processed into a Fischer-Tropsch syncrude intermediate product that is upgraded via hydrocracking into kerosene. The renewable kerosene can be easily shipped towards the large consumption centres in the Americas, Europe, and Asia.

8.4.2 Requirements and evidence provision before the start of RFNBO production

8.4.2.1 Requirements to be fulfilled

During the **2022-2027** construction period, the kerosene producer is aware that to be eligible to claim renewability for its consumed electricity via Case 2, two requirements must be met before it start hydrogen production:

It must prove that the whole complex is isolated from the public grid.

It must prove that the linked RE installations did not start their commercial operation before the electrolyser. The start of their commercial operation must qualify as at the same time or later.

8.4.2.2 Efforts and costs for RFNBO producer to provide evidence

The kerosene producer easily fulfils both requirements through the set-up of the entire off-grid system. During the commissioning process, the producer demonstrates that the entire complex does not use a connection to the public grid and that it does not include any RES-E plants that have formerly been connected to the public grid.

There are no costs related to the evidence provision because the set-up of the complex itself intrinsically provides all the necessary evidence. The RFNBO certification authority participates in the commissioning process of the installation and verifies and confirms the off-grid status and the non-inclusion of old RES-E installations. It also verifies that no conventional power plants are integrated in the virtual power plant.

8.4.2.3 System-level impacts

There are no system-level impacts because the complex is not connected to the overall electricity grid.

8.4.3 Requirements and evidence provision during RFNBO production

Kerosene production starts in **2027**. Due to the off-grid production sites, the project team's proposed methodology does not include any requirements to be fulfilled during the RFNBO production. The kerosene producer can focus on scaling its fuel production and does not need to provide any evidence unless urban development leads to a subsequent connection to the overall electricity grid. Given that there are no requirements to be fulfilled, there are also no activities to be carried by the certification authorities. However, random audits are conducted to check whether standard operation of the facility has changed.

There are no system-level impacts during production because the complex is not connected to the overall electricity grid. However, the electrolyser and the electrical battery must provide the required flexibility to run the fuel production process.

8.4.4 Summary and learnings from this case study

This case study exemplifies the process of evidence provision to claim 100% RES-E for an off-grid kerosene producer that runs a complex VPP where electrolyser, PV plant, wind park, and Fischer-Tropsch facility are interlinked via direct connections. It shows that off-grid RFNBO production sites dispose of one major benefit regarding the evidence provision to claim 100% RES-E: Once the off-grid status is confirmed during the commissioning process, no additional evidence needs to be provided during the fuel production itself. This process reduces the administrative burden for the kerosene producer to claim renewability for the electricity consumed in the electrolysis process.

8.5 Case study 5: Kerosene production with RES-E GOs in Poland (Case 3)

8.5.1 Introduction

In this case study, a fictitious refinery operator in Poland intends to enter synthetic green kerosene production. The grid emission coefficient in Poland is too high to produce under Case 1. The site in the industrial estate where the kerosene production is planned to be installed does not have sites nearby that allow for the development of colocated RES-E capacities under Case 2. Sourcing RES-E under Case 3 through a PPA is also difficult because the market for corporate RES-E PPAs in Poland is still illiquid. The operators plan to develop their project with a plan to operate under Case 3 with RES-E sourcing through the wholesale market GOs. The production facility consists largely of the following units:

- 100 MW grid-connected ALK electrolysis
- CO_2 capture at natural gas combustion unit in the same refinery site
- Fischer-Tropsch synthesis to form hydrocarbons from hydrogen and CO_2

- Processing of the resulting hydrocarbon mixture to kerosene carried out in existing refinery units

Table 10. Main parameters of case study 6

Main characteristics	Borderline Case
Cases applied by RFNBO producer	Case 3, plus non-renewable fuel
Type of RFNBO installation	100 MW Alkaline electrolysis and subsequent Fischer-Tropsch synthesis (+ CO_2 capture demand)
Final RFNBO product(s)	Liquid hydrocarbons, mainly kerosene
Owner/operator of RFNBO installation	Regional refinery operator
Location of RFNBO installation	Poland
Electricity procurement model, technology type(s) of RES-E sources	Sourcing through wholesale market (electricity and GOs), no bilateral RES-E PPA in place
Connection between RFNBO and RES-E installation(s)	Not applicable (RES-E is not sourced from specific assets)

This case demonstrates a more abstract link between RES-E production and RFNBO production. It represents the most common practice of (virtual) RES-E procurement by industry.

8.5.2 Requirements and evidence provision before the start of RFNBO production

There are no direct requirements related to RFNBO asset installation (in contrast to Case 2, for instance, where the plant needs to be set-up a specific way to be compliant). The refinery does not intend to close a PPA with a RES-E producer, meaning that they do not have to set that up upfront to fulfil criteria.

The company takes steps to bring the facility they are installing into compliance in the operational phase. This compliance includes working with an energy (and GO) trading company to scan the market for eligible additional RES-E assets in Poland and to design the production units in a way that they can fully comply with temporal correlation. These aspects are discussed in Section 8.5.3. The refinery company plans and installs the facility, and on 13 January, 2024, the asset is commissioned and ready to produce RFNBOs.

8.5.3 Requirements and evidence provision during RFNBO production

8.5.3.1 Requirements to be fulfilled

The RFNBO production facility needs to fulfil the following requirements to sell the kerosene as 100% renewable RFNBO under RED II:

- Sourcing additional RES-E
- Geographical correlation
- Temporal correlation

As the facility is commissioned on 13 January, 2024, the operator enjoys the less strict rules of Phase 1 until the end of 2024 to fulfil above requirements (see Section 7).

8.5.3.2 Choice of producer to provide evidence as simply as possible

The operator intends to rely on GOs to demonstrate compliance with the RED II requirements, meaning that:

- **For each MWh consumed,** a GO must be cancelled.
- Each GO must come from a RES-E asset commissioned no earlier than 13 January, 2022 (2 years before the RFNBO installation). The RES-E asset must also not be subsidised. By the end of 2024, however, only 40% of GOs used need to **fulfil the additionality criteria** because of the more relaxed requirements in Phase 1.
- Each GO must come from the same bidding zone as the RFNBO asset, meeting requirements for **geographical correlation**. Because Poland consists of one bidding zone, the GO can come from anywhere in Poland. Theoretically, Poland could identify RFNBO-suitable areas for RFNBO production within their bidding zone to avoid future grid bottlenecks. However, Poland has not designated such areas by 2024, and GOs can be sourced from anywhere in the bidding zone.
- Compliance with **temporal correlation** requirements is not connected to GOs. Temporal correlation is fulfilled by producing only on days where the RES-E share in the Polish bidding zone is at least the annual average 2 years before (see Section 6.4.3.4 for details).

8.5.3.3 Efforts and costs for RFNBO producer to provide evidence

The refinery operator first plans the plant's operation (i.e. how to comply with temporal correlation). In **2024**, production can only take place on days where the intermittent RES-E share in Poland is above the average of 2022, which was 12%.[75] In 2020, this requirement was met roughly 60% of the time, as Table 10 and Figure 18 show. This results in an expected operation time of around 5,300 hours and corresponding electrolysis electricity consumption of 530 GWh.

The expected hydrogen output is 382 GWh, or 11.5 kt per year. This output will be reacted with an annual amount of 92.3 kt CO_2, producing 5.1 kt hydrocarbons with a chain length between 5 and 12 as a product and 14.1 kt longer chain hydrocarbons as a byproduct, which may be cracked to also yield the desired chain length.[76] Scrubbing and compressing CO_2 for the hydrocarbon synthesis requires around 360 MWh per kt CO_2, resulting in an annual demand of 33 GWh. Other production units require only minor amounts of electricity in comparison, and are not included when demonstrating compliance with RED II requirements.

Based on this operation plan, the RFNBO producers estimate consumption of 563 GWh RES-E per year. They mandate their electricity supplier to source the corresponding amount of GOs as follows:

- 563,000 GOs must be sourced in total, each one representing one MWh.
- All of those GOs must be generated from Polish RES-E assets in 2024.

[75] For the sake of this case study, the intermittent RES-E share is used as benchmark. The total RES-E share may also be used as benchmark.

[76] Mass balances in this example are based on figures from Task 1 of this project.

- 337,800 GOs (60%) must come from unsubsidised RES-E assets commissioned no earlier than 13 January 2022.

Generally, this type of GO sourcing can be delivered by electricity traders. The only problem is that there is a shortage of GOs from new, unsubsidised RES-E assets in Poland because most RES-E expansion takes place within the national carbon contracts for difference (CfD) auction scheme. Only a few merchant RES-E projects have been developed, meaning that they charge a high price of 30 EUR/MWh for their GOs. However, in Phase 1 in 2024, only 60% of GOs need to fulfil this criteria; the remaining 40% of GOs cost only 0.7 EUR/MWh, leading to an effective price premium of 18 EUR/MWh, in total 6.1 million EUR. In Phase 2, 100% of GOs will need to fulfil these criteria.

RFNBO production can commence with GO procurement and with additionality and geographical correlation compliance taken care of. To comply with temporal correlation, production can only take place on days where the RES-E share in the Polish bidding zone is at least 12% in the day-ahead forecast. The refinery operator monitors the day-ahead forecast every day at 18:00 hours immediately after publication by the TSO (PSE) and then plans production for the next day. In 2025, the operator will do the same thing, but it will need to plan production for the next day at an hourly basis rather than baseload production for the full day. This change in planning is because the granularity of temporal correlation will switch from daily to hourly in Phase 2, which begins 2025.

The ALK electrolyser has to keep a minimum load of 10% (i.e. 10 MW) at all times for technical reasons. This means that on days where RED II-compliant production cannot take place due to low RES-E infeed, 240 MWh of non-renewable hydrogen is produced. This is the case in 114 days, leading to power consumption of 27 GWh. At a power price of around 100 EUR/MWh[77], this amounts to costs of 2.7 million EUR; however, 1.0 million EUR of these costs are offset because the non-renewable hydrogen can be used in the refinery, saving natural gas. The net compliance cost is 1.7 million EUR.

Another issue with temporal correlation is that it results in an intermittent production pattern of hydrogen and CO_2, but the Fischer-Tropsch reactor requires a steady supply with these feedstocks. The refinery operator decides to install CO_2 and hydrogen storage tanks, which buffer hydrogen and CO_2 production and allow for a steady stream into the Fischer-Tropsch reactor. Hydrogen storage is the most expensive part in this case study as the reactor needs 32 tonnes of hydrogen per day. To be safe, the refinery decides to construct a hydrogen overground tank with a capacity of 150 tonnes. The investment cost for this tank amounts to 8.5 million EUR, translating into annualised costs of 960,000 EUR.

In total, the compliance costs of procuring eligible GOs, producing non-renewable hydrogen in times with too little RES-E infeed, and installing hydrogen storage amounting to 8.8 million EUR.[78] This translates into 0.42 EUR/kg of hydrocarbon produced. The operator calculates its total cost to produce this RFNBO to be 4.50 EUR/kg, meaning that compliance with RED II requirements leads to a cost hike of around 10%.

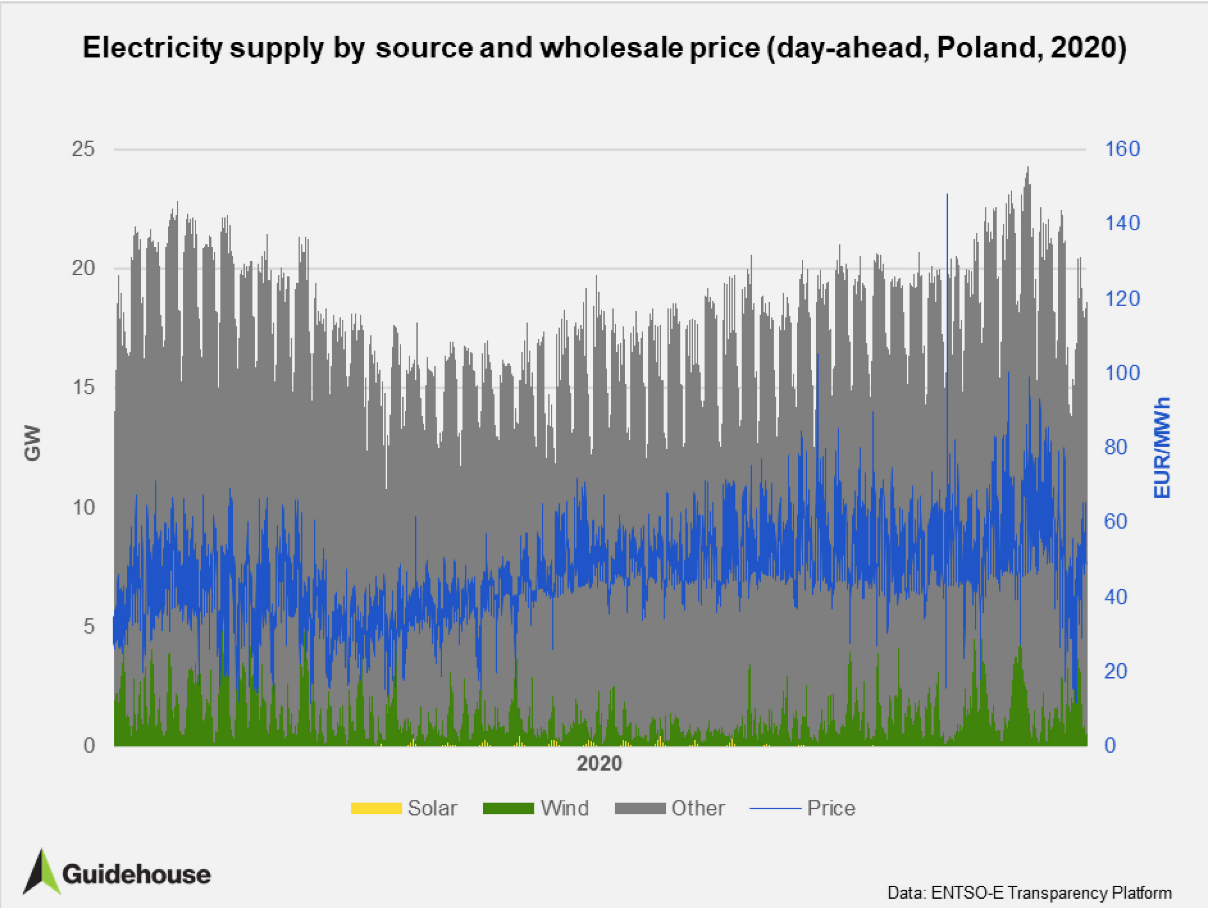
RFNBO production costs are a multiple of the costs of conventional kerosene, which is around 0.60 EUR/kg. The refinery operator needs to find off-takers willing to pay a large price premium regardless of additional costs from RED II compliance. Having its fuel eligible as 100% renewable RFNBO opens opportunities to sell the fuel at a price premium, and the refinery operator sells the kerosene to Germany and other markets where airline operators have to use increasing shares of RFNBO as part of the national implementation of RED II

[77] Assuming retail prices by Eurostat.

[78] This number does not include the opportunity cost of running the electrolyser with a higher load factor.

Article 25's target. This obligation, combined with a still comparably low offering of RED II compliant kerosene in Europe, allows the RFNBO producer to charge a price premium that covers its costs.

Figure 18: RES-E share and electricity price analysis Poland 2020



Source: Guidehouse, ENTSO-E Transparency Platform

Table 10 summarises assumptions in the calculations.

Table 11. Technical parameters of the hypothetical kerosene production plant in Poland.

Parameter	Value	Unit
Uninterrupted kerosene demand	32	t H_2 per day
Annual average intermittent RES-E share (2020)	10	%[79]
Hours with above-average intermittent RES-E share (day-ahead)	5,268	hours/year
	60	% of hours
Average wholesale electricity price during hours with above-average intermittent RES-E share (day-ahead)	41.38	EUR/MWh[79]
GO price (from new RES-E assets in Poland)	0.7	EUR/MWh[80]

[79] ENTSO-E Transparency Platform. "Day-ahead Prices," "Generation Forecasts for Wind and Solar," "Generation Forecasts – Day ahead, Actual Generation by Production Type."

[80] Price indication based on quotation from broker for GOs that meet criteria (age, location); Guidehouse project experience.

Parameter	Value	Unit
GO price (from new, unsubsidised assets in Poland)	30	EUR/MWh
Electrolyser efficiency	72%	
Discount rate	7.5%	

8.5.3.4 Efforts for auditors/administrations to examine evidence

In **February 2025**, the audit for compliance of the kerosene production in 2024 is due. The refinery operator submits to the auditing entity:

- The hourly load profile of the relevant units (electrolyser and CO_2 capture), summing up to 590 GWh[81]
- The data of all RES-E GOs they cancelled (563,000 GOs were cancelled in total)
- The day-ahead forecast RES-E share in the Polish grid that was used
- The facility's hourly hydrogen and CO_2 output profile
- The amount of fuel they labelled as 100% renewable RFNBO (19.2 kt) and the amount of hydrogen and CO_2 used for its production

The auditing entity then checks that:

- The sum of annual electricity consumption is covered by the same amount of GOs because 563,000 GOs amount to 563 GWh, which covers the annual relevant consumption of 563 GWh.
- Of the GOs, 60% come from RES-E assets commissioned no earlier than 13 January, 2022, and are not subsidised. This information is available in the GO registry, and the producer is found to be compliant.
- All GOs stem from RES-E plants in Poland. This information is available in the GO registry, and the producer is found to be compliant.
- The amount of hydrogen consumed by Fischer-Tropsch synthesis corresponds to the amount produced by the electrolyser on days with above-average RES-E share in Poland. This information is easily checked by comparing the electrolyser load and output profile with the RES-E day-ahead forecast and the hydrogen consumption data.

Based on these checks, the auditor confirms the RFNBO producer was fully compliant with the requirements and rightfully labelled the 19.2 kt hydrocarbon fuels produced in 2024 as 100% renewable RFNBO. Nineteen GWh of hydrogen were produced in times of below-average RES-E share in the grid because the electrolyser had to run at minimum capacity. These volumes are not eligible to count as RFNBOs. The producer used this hydrogen as conventional hydrogen and did not declare it as renewable, so all regulations are complied with.

This process is straightforward for the producers and the auditors. The RFNBO producer only needs to submit data they compiled during production, and most datasets are created as industrial best practices regardless of RED II requirements (e.g. load profiles and output

[81] 530 GWh from RED II compliant electrolysis, 27 GWh for non-compliant must-run electrolysis, and 33 GWh for CO_2 provision.

data). The auditor only needs to make simple quantitative checks, which can be automated if the data is submitted in a harmonised format.

In **2025**, the RFNBO producer will go through the same process again. The only major difference will be that Phase 2 will already be in force that year. It will have to comply with temporal correlation, not looking at whole days but evaluating compliance every hour, albeit still based on the day-ahead forecast.

More importantly, the RFNBO producer will have to procure all GOs (as opposed to only 60% in 2024) from new, unsubsidised assets. This procurement may pose a risk if there are not sufficient GOs listed at an acceptable price on the market. The company takes two measures to hedge this risk:

- Closing long-term GO purchase agreements with eligible RES-E assets
- Approaching a RES-E project developer to close a PPA for a 20 MW share of a new to-be-developed wind farm in Poland

This way, parts of its electricity consumption will be safely covered outside the possibly volatile market for GOs fulfilling additionality criteria.

8.5.3.5 System-level impacts

This project has impacts on the Polish electricity system regarding RES-E deployment, GHG emissions, flexible RES-E integration, and grid constraints:

- Relying on GOs, the RFNBO producer does not directly trigger the installation of new RES-E assets. However, the high price for GOs fulfilling additionality criteria (30 EUR/MWh in this case study) is enough for RES-E projects to cover their cost gap, possibly allowing for higher margins than when participating in the national CfD auction scheme. This growing demand from RFNBO producers incentivises RES-E producers to install new capacities outside support schemes.[82]
- As stated above, the RFNBO producer does not directly trigger additional RES-E generation in the beginning. The additional electricity demand from RFNBO production may initially be partly covered by fossil generation, leading to some GHG emissions compared to a counterfactual without RFNBO production. This increase in emissions is only the case in the beginning of large-scale RFNBO production, however. Once RFNBO production is established and a corresponding demand for more expensive additional GOs is created, it expected to trigger additional RES-E generation. Then, there will not be additional GHG emissions.
- The RFNBO producer can only operate at times of high RES-E shares. Due to relatively low installed RES-E capacities in Poland, the marginal power plant in hours of operation is most likely non-renewable. RES-E system integration benefits are also limited in this situation. However, motivation for this requirement is to confirm the RFNBO facility can demonstrate it does not consume non-renewable electricity. This demonstration is achieved by following RES-E infeed and procuring geographically correlated, additional RES-E.
- The refinery is located in central Poland near Warsaw and may aggravate existing east-west grid constraints. For instance, if the envisaged newly developed wind farm

[82] RES-E producers will most likely not be able to develop bankable projects solely built on volatile GO prices. Set ups in which a singly RES-E project is partly marketed through a support scheme (at low margin) are more likely, partly through PPAs and partly on a merchant basis, which would entail selling additional GOs at possibly high margins.

is in the Szczecin area, this may put additional strain on the electricity transmission network.

8.5.4 Summary and learnings from this case study

This case study also provides some hints about the practical aspects of implementing the proposed methodology:

- Demonstrating compliance with the requirements does not create a disproportionate administrative burden. Producers only need to submit datasets they need to compile during production anyway, and most of those would be compiled even in the absence of any RED II requirements. Auditing is also not complex and could be partly automated.
- GOs fulfilling the defined criteria allow for RFNBO production in markets where RES-E PPAs are not sufficiently available while ensuring sustainability and geographical correlation. However, RFNBO and RES-E producers may not want to rely on potentially volatile or illiquid markets for additional GOs. Long-term GO purchase agreements or PPAs may be the prevalent sourcing model in the near-term to give security to both sides.
- A transition phase with softer additionality requirements is vital to allow for a timely RFNBO ramp-up. In Poland and many other EU Member States, the supply of new, unsubsidised RES power is still low, with most projects being developed under government schemes and not counting as additional.
- Compliance costs are significant. However, RFNBOs need to be marketed with a substantial price premium in any case due to their high costs. The opportunity to sell RFNBOs to off-takers, as obligated in the RED II context, may justify the compliance costs. The motivation to use RFNBOs is the diffusion of RE and GHG reductions, leading to requirements, such as additionality. These objectives should not be played against compliance costs.

8.6 Case study 6: Hydrogen production with a contracted offshore wind farm in the Netherlands (Case 3)

8.6.1 Introduction

In this hypothetical case study, a refinery is currently purchasing additional grey hydrogen (merchant) for its production. The merchant production comes from an inflexible SMR nearby; it has a cold start-up time between 15-24 hours and minimum capacity of about 40% of its nominal capacity (operating at such low capacity significantly increases its costs). The refinery now aims to switch away from this SMR-based hydrogen. As such, the SMR production must be fully substituted with electrolysis (RFNBO facility).[83]

The RFNBO facility is designed to meet the constant refinery hydrogen demand of 2 tonne/hour H_2. The producer investigated several options to meet this demand in terms of electrolyser sizing, RES-E sourcing options and hydrogen storage. The RES-E is sourced primarily from an offshore wind farm via a partial, non-exclusive PPA and secondarily via the wholesale market using energy trading companies. The electrolyser has a minimum load of

[83] Investigating whether existing SMR that has been designed to operate optimally at its nominal capacity can efficiently and systematically run at flexible and much lower than nominal capacities is outside of the scope of this case study. There would likely be a significant increase in GHG emissions and a decrease in efficiency on a per tonne of hydrogen produced basis.

10% of the nominal capacity that is treated in a must-run operating mode, at times running even without RED II compliance. Table 11 summarises the case study parameters.

Table 12. Main parameters of case study 6

Parameter	Description
Cases applied by RFNBO producer	Case 3
Type of RFNBO installation	PEM electrolysis, capacity dependent on sourcing option
Final RFNBO product(s)	Hydrogen, to be supplied to a nearby refinery
Owner or operator of RFNBO installation	European oil & gas company
Location of RFNBO installation	Netherlands
Electricity procurement model, technology type(s) of RES-E sources	Primary sourcing via partial, non-exclusive PPA with an offshore wind farm. Additionally, some RES-E sourcing via wholesale market to increase full load hours.
Connection between RFNBO and RES-E installation(s)	Electrolyser and offshore wind farm are both in Netherlands and connected via national electricity grid.

8.6.1.1 Purpose of this case study in the overall context of this project

This example may be one of the most common use cases in the short term. The use of green hydrogen in refineries is the only major direct application of transport RFNBOs in the industrial sector, where most potential hydrogen uses reside.

The following sections illustrate options to meet the constant hydrogen demand, influenced by the policy requirements, which can significantly change the business case of such a project. This case also exemplifies green hydrogen use in industries in general and some of its implications.

8.6.1.2 Type of RFNBO producer and techno-economic background of the production case

The two basic requirements of this case are to meet both total yearly demand **and the constant demand** of **the refinery.** First, the project team illustrates several ways to meet the total yearly demand, as Table 12 summarises. The base option does not meet the RED II criteria and is used to compare how electrolysers could be scaled to meet the required yearly hydrogen demand in RED II's absence (hence using only GOs without RED II requirements as a proof of RES-E sourced). Both the PPA and PPA-plus wholesale market options are designed so that 100% of the produced hydrogen can be considered RED II-compliant. The different RES-E sourcing options have significant impact on the installed capacity of the electrolyser and, hence, on CAPEX requirements.

Table 13. RES-E sourcing options to meet the total yearly demand

	Base option	PPA	PPA-plus wholesale market
RES-E sourcing	GOs (without meeting RED II criteria)	PPA with offshore wind farm	PPA with offshore wind farm, additional sourcing from wholesale market
Achievable FLH	8,000 (8,760 minus expected downtime)	4,000 (FLH offshore wind)	4,000 plus 1,000

	Base option	PPA	PPA-plus wholesale market
Wholesale electricity price (simple)[84]	35 EUR/MWh	N/A	N/A
Offshore wind LCOE	N/A	50 EUR/MWh	50 EUR/MWh
Wholesale electricity price (additional)[85]	N/A	N/A	45 EUR/MWh
Electrolyser installed capacity[86]	**112.3 $MW_{el\ in}$**	**224.6 $MW_{el\ in}$**	**179.7 $MW_{el\ in}$**

Source: Guidehouse

The alternative to oversizing the electrolyser is to produce partly non-compliant hydrogen (as in the base option) and bear the associated risk and additional cost in the business case. Table 13 illustrates that the business case for green hydrogen (both PPA and PPA-plus wholesale market options) need to be subsidised to compete with grey and blue hydrogen production. The subsidy would cover the price gap (difference to grey or blue) between the RED II-compliant hydrogen and grey hydrogen (plus ETS costs) or blue hydrogen (plus ETS costs). The risk and potentially additional cost in this example would be based on falling back to the base option for part of the electrolyser production and not receiving this subsidy for 100% the hydrogen produced but only part of the total production. This additional risk and associated cost can be illustrated as the difference between the costs in the base option and regular SMR grey hydrogen production (19 EUR/MWh, including ETS cost of 40 EUR/tCO_2 for SMR production).

Second, a constant uninterruptible (8,760 hours/year) demand set at 2 tonnes H_2/hour (66.7 MWh, LHV) must be met due to the refining process' extreme inflexibility (i.e. it requires predictable and stable supply of hydrogen to operate efficiently and safely). The electrolyser will have to either fully (PPA option) or partly (PPA-plus wholesale market option) follow the variations in the intermittent offshore wind production, which will further impact its business case.

Table 14. Hydrogen production cost estimation for different options (EUR/MWh H2)[87]

	Estimated hydrogen production cost[88]	Difference to grey (blue)	Electricity cost share of total LCOH
Grey hydrogen (SMR)	55 [89]		
Blue hydrogen (SMR + CCS; 90% capture rate)[90]	61		
Base option	74	19 (13)	77%
PPA option	115	60 (54)	70%
PPA-plus wholesale market option	106	51 (45)	74%

[84] Simple price means illustrative average annual electricity price on the wholesale market.

[85] Additional price means sourcing from the wholesale electricity market in a way that complies with the possible criteria under RED II for not directly contracted RES-E assets.

[86] Assuming 65% system energy efficiency, LHV.

[87] CAPEX of 1000 EUR/k$W_{el\ in}$, OPEX at 2% of starting CAPEX/year, electrolyser system efficiency at 65% (LHV), a discount rate of 7.5%, a lifetime of 20 years.

[88] Including ETS costs at 40 EUR/tCO_2.

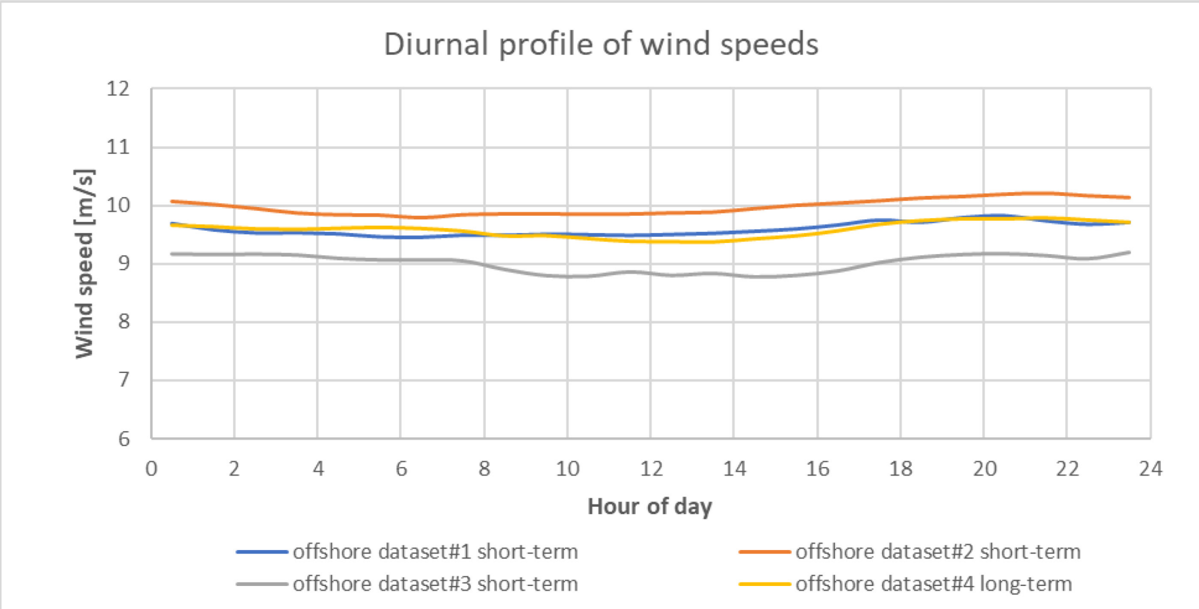
[89] Assuming a benchmark SMR process at 253 kgCO_2/MWh H_2 (LHV). Cost based on (Guidehouse, 2020).

[90] Cost based on (Guidehouse, 2020).

Source: Guidehouse

Electricity production on wind farms is highly site-specific and depends on several parameters.[91] However, the production is always firmly contingent on the long-term wind resource at the site. Observing the temporal variation of wind speed gives an indication of the expected production pattern throughout a year.[92] Both diurnal and monthly variations of wind speeds are of importance. Figure 19 and Figure 20 show profiles for multiple measurement locations in the Dutch North Sea.[93] The diurnal profile exhibits minimal variation in wind speed (4%-5% minimum-maximum variation) and is fairly consistent throughout daytime and night time. The monthly profile shows significant variation (31%-40% minimum-maximum variation). In general, winter months have higher average wind speeds, and so more RES-E production would be expected in these months (related to rated power of the wind turbines).

Figure 19. Diurnal profiles of four offshore wind farms in the Dutch North Sea



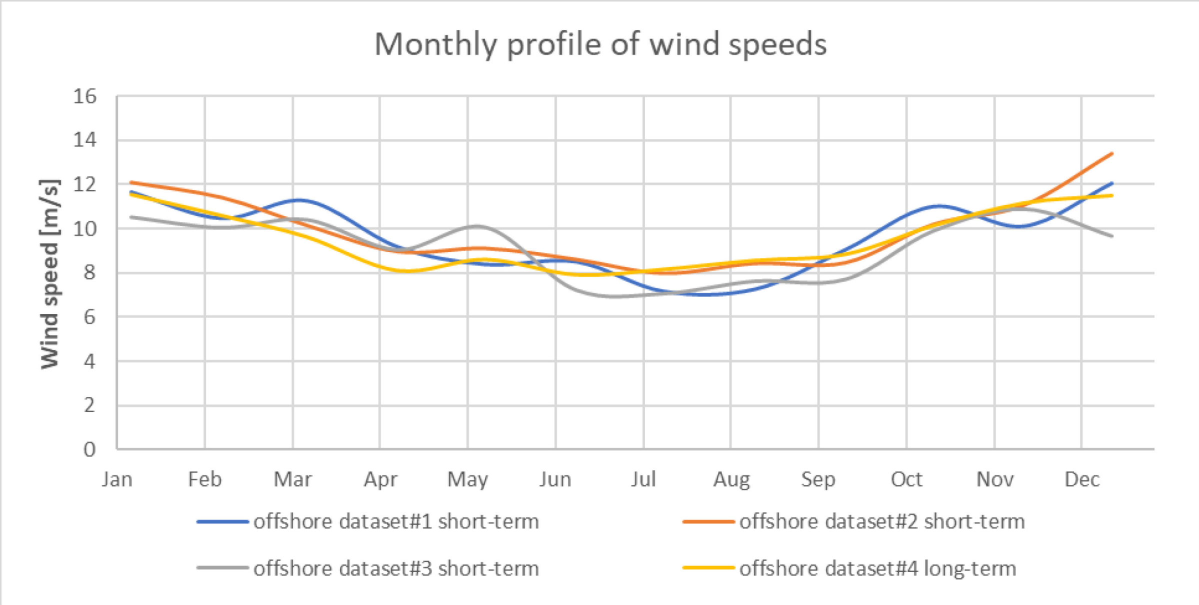
Source: Guidehouse

[91] These parameters include the type of turbine selected, the hub height, the layout of the wind farm, the presence of neighboring wind farms, and other factors.

[92] The project team has omitted the cube dependency between wind speed and power production here. In general, the variation in electricity output will be somewhat greater than the variation in wind speed.

[93] Guidehouse calculations.

Figure 20. Monthly profiles of four offshore wind farms in the Dutch North Sea



Source: Guidehouse.

The hourly variation should not present a significant challenge in meeting the constant refinery demand. However, the monthly variation might create a significant issue for electrolyser sizing or the need for large-scale hydrogen storage.[94]

Table 15. Estimated need for peak hydrogen storage

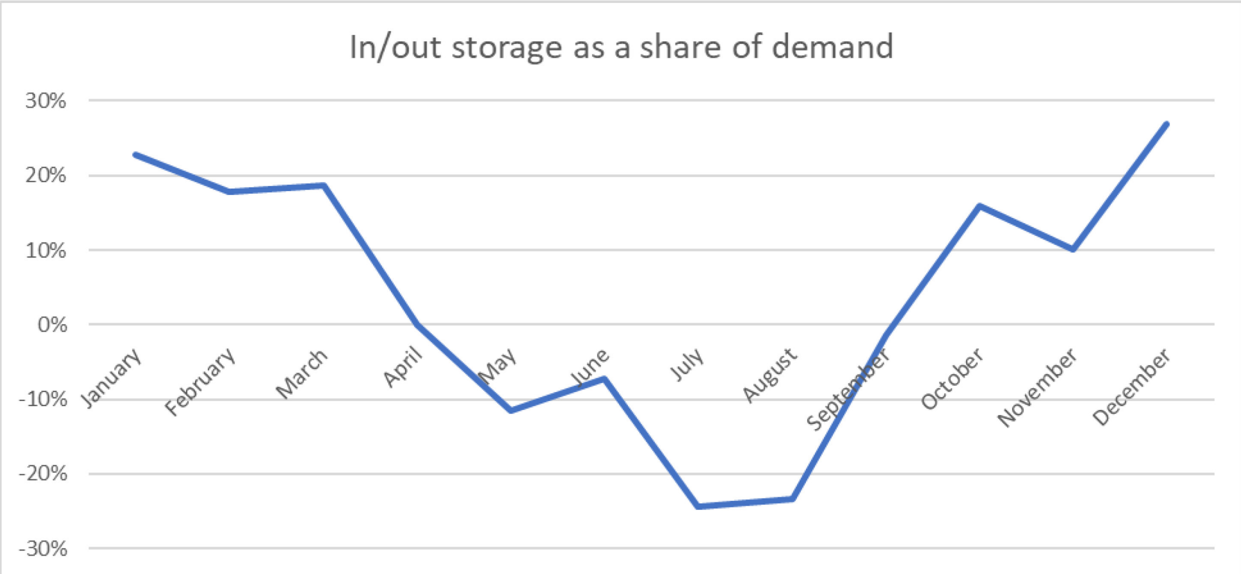
Month	Monthly demand for hydrogen	Monthly change in hydrogen production (stylised)	In/out storage monthly storage flows (storage)	In/out storage as a share of demand	Momentary storage balance
	MWh H_2 (LHV)	*April is 100%*	*MWh*	*%*	*MWh*
January	49,600	127%	11,296	23%	11,296
February	44,800	114%	9,894	22%	21,190
March	49,600	123%	9,216	19%	30,406
April	48,000	100%	0	0%	30,406
May	49,600	91%	-5,738	-12%	24,668
June	48,000	93%	-3,485	-7%	21,182
July	49,600	78%	-12,092	-24%	9,090
August	49,600	79%	-11,580	-23%	-2,490
September	48,000	99%	-669	-1%	-3,159
October	49,600	120%	7,894	16%	4,735
November	48,000	110%	4,865	10%	9,600
December	49,600	131%	13,334	27%	22,934

[94] As with meeting the total yearly demand, meeting the constant demand can be resolved by partial non-compliant hydrogen production. In such a case, the hydrogen is still physically produced by the electrolyser as illustrated in the Base option, however only part of that hydrogen is RED II compliant, thus altering the business case, similar to the effect described in Table 13 above.

Source: Guidehouse

Table 14 summarises an illustrative impact of the monthly wind speed variations on electricity production and the need for peak hydrogen storage to meet the uninterruptible refinery demand at 66.7 MWh H_2. April was selected as a base month for electrolyser sizing (i.e. expected production in April meets 100% of the expected demand in April). Monthly flows in (plus) and out of (minus) storage are calculated from the base month, as are momentary storage balance (volume of hydrogen currently in storage). The results show the need of minimum 30.4 GWh of peak hydrogen storage (62% of average monthly demand). Figure 21 shows in and out storage flow as a share of a total monthly demand.

Figure 21. Hydrogen in and out storage flows as a share of a total monthly demand



Source: Guidehouse

Table 15 depicts the possible storage investment cost implications for the project tailored to the assumptions of the PPA case and corresponding electrolyser sizing.

Table 16. Hydrogen storage requirements in the PPA option

Parameter	Monthly demand for hydrogen	Unit
Minimum storage capacity needed	30,406	MWh
CAPEX RFNBO plant	161,280,000	EUR/224MW$_{el\ in}$
Investment cost of storage	334	EUR/MWh (salt cavern)
CAPEX storage	10,155,593	EUR
Additional project cost[95,96]	6%	% storage cost/cost of RFNBO plant

95 This data only includes CAPEX for salt cavern hydrogen storage. Salt caverns might be limited by their availability. The cost does not include OPEX (e.g. compression costs).

96 Onsite storage in the volumes required to balance the system is currently not technically feasible. Some level of balancing is possible if production or demand is connected to a hydrogen pipeline infrastructure. However, such assumptions are outside of the scope of this case study, which assumes point to point connection between supply and demand.

Source: Guidehouse

8.6.2 Requirements and evidence provision before the start of RFNBO production

The RFNBO plant has a date of commissioning (DOC) scheduled for June 1, 2023. The contracted offshore wind farm is scheduled to be commissioned 1 year after—on June 1, 2024. As the offshore wind farm is of significant size (1 GW installed capacity), only part of that capacity is contracted by the RFNBO plant. In the gap year before the DOC of the RFNBO plant and the wind farm, the RFNBO plant is fully dependent on the wholesale market sourcing where it must seek power from eligible RES-E assets. Given the probable unavailability such RES-E assets on the market in 2023, the RFNBO plant will likely not be able to meet the scheduled demand of the refinery in the first year of the operation. When the wind farm begins operation, the RFNBO operator will seek to scale their production via additional sourcing from eligible RES-E assets on the wholesale market.

8.6.2.1 Requirements to be fulfilled

Before commencing operation, the RFNBO plant will have to secure the PPA with the wind farm. The wind farm will have to be commissioned no earlier than 2 years before the DOC of the RFNBO plant, which is fulfilled in this case. Additionally, the wind farm would either have to be subject to no direct subsidies (e.g. investment aid or feed-in tariffs) as a whole or separated in tranches where part runs under the direct subsidies and the other part is undersigned via the PPA with the RFNBO producer (if this is allowed in the MS legislation). Lastly, the wind farm must be located in the same bidding zone as the RFNBO plant—the country (or the seas) of the Netherlands, in this case.

The RFNBO operators will also have to scan the market for eligible RES-E assets that they do not have a direct contractual relationship with to increase production in the first year of operation and after the wind farm becomes operational to further scale their production. These assets can be outsourced to energy (and GO) trading companies. As with the contracted wind farm, these RES-E assets will have to be located in the same bidding zone, be unsubsidised, and have DOC no later than 2 years before the RFNBO plant.

8.6.2.2 Efforts and costs for RFNBO producer to provide evidence

The additional efforts of the RFNBO producer before the start of production are not significantly increased due to compliance requirements. The main effort will consist of a detailed understanding of RED II requirements, PPA negotiations, and possibly contracting an energy (and GO) trading company to assist with scanning the market for eligible, additional RES-E assets.

Most the compliance cost before commencing operation will be related to additional electrolyser capacity—expected limited full load hours (FLHs)—and investment into storage—requirements to follow intermittent RES-E. Additional cost can be incurred as part of the increased risk profile of RFNBO production under the RED II requirements due to delays in the construction of the contracted wind farm and the unavailability of eligible assets from the wholesale RES-E market.

8.6.2.3 Efforts for auditors or administrations to examine evidence

The efforts of the administrators before the start of RFNBO production are also limited. There is no real ex ante verification required since the PPA only comes into effect in the second year of the RFNBO plant's operation and wholesale sourcing (e.g. via GOs) from eligible assets can only be verified ex post.

8.6.3 Requirements and evidence provision during RFNBO production

8.6.3.1 Requirements to be fulfilled

During its operation, the RFNBO plant will have to continuously fulfil the additionality requirement and temporal and geographical correlation. In the first year of its operation, this fulfilment will be carried out through wholesale market sourcing from eligible RES-E assets, possibly demonstrated by purchasing eligible GOs. Before the effective contractual date of the PPA with the offshore wind farm, the RFNBO operator will have to seek approval from the auditors, which will verify the eligibility aspects of the wind farm to provide electricity for this particular RFNBO facility.

8.6.3.2 Efforts and costs for RFNBO producer to provide evidence

The RFNBO producer will have to demonstrate that the amount of electricity sourced from eligible assets is corresponding to the volumes of RFNBO (green hydrogen in this case) produced (after conversion losses). This demonstration would likely happen via a yearly audit from an independent auditor. The audit would likely have to be initiated by the RFNBO producer and possibly checked by the hydrogen support scheme operator, if eligible.

As the RFNBO operator uses both a PPA and the wholesale market for its electricity sourcing, it has to prove compliance with RED II for both options. For the PPA sourcing, the RFNBO operator would have to deliver the production data from the contracted wind farm for the past year (day-ahead or intraday forecast) alongside a still valid PPA contract. Furthermore, proof of unsubsidised status, newness, and location in the same bidding zone (both relative to the RFNBO facility) would have to be provided.

For the power sourced via the wholesale market, GOs from the eligible assets would have to be presented. These GOs could only be sourced from RES-E assets fulfilling at the same time:

- **Additionality**, meaning DOC and unsubsidised status from national GO registry
- **Geographical correlation**, where this information is already on the issued GO or in the national GO registry
- **Temporal correlation**, which is checked by the auditor based on national hourly RES-E shares in the past year. The RFNBO operator has to prove that the MWh from the wholesale market were only sourced in times of RES-E shares above the national average of the year 2 years prior.[97]

Finally, the auditors should take the generation data from the PPA asset as a baseload and combine it with the wholesale market procurement data. This data is used to arrive at a total electricity procurement profile for the RFNBO plant with hourly granularity for the past year. This information is, in turn, compared to the RFNBO plant production profile, and the share of RED II-compliant RFNBO production is determined.

It is important to also consider the risks related to compliance and possible additional costs. Because of the considerations for uninterruptible demand, hydrogen would be likely

[97] If 2023 was the first year of the RFNBO operation, the average RES-E share of the years 2021 and 2022 would be considered.

generated regardless of whether fully RED II-compliant or not. Expectedly, RED II hydrogen production (and use) will be linked to a support scheme (e.g. subsidies) due to the price gap to conventional or alternative (blue) option (see Table 13). One option for RFNBO producers is to design their business case around 100% RED II-compliant production, forcing them to oversize their electrolyser or invest in large-scale storage. Alternatively, they can accept that part of the produced hydrogen will not be RED II-compliant (grey), and subsidies will not be available for that part of the production. Where the share of RED II-compliant hydrogen supplied to the end customer (e.g. refinery) is lower than expected, costs rise (less subsidies available), and this inherent risk has to be managed in the business case.

Dealing with deviations from expected RES-E production and resulting RFNBO volumes can also have significant impacts on the PPA costs, although this depends on the specific way the PPA is constructed. On the one hand, there is a risk that the contracted RES-E assets produce less power than the forecast day-ahead. In case the RFNBO production was already scheduled against this forecast, less than expected volumes of RFNBOs are produced (i.e. the hydrogen is still physically produced, yet less of the total volume complies with RED II). It is important to determine who takes on the responsibility of managing this risk between expected (forecast) and real production—whether the electricity generator (RES-E asset), hydrogen producer (RFNBO plant), or hydrogen consumer (refinery). This risk is normally managed by the party that is best positioned to manage it. Table 16 summarises some of the main considerations related to the risks from forecasting errors related to RFNBO production volumes.

Table 17. Responsibility for the risk from forecasting errors and considerations

Risk responsibility	Considerations
RES-E asset operator	• Best positioned to manage risk • Can contract energy trader with a portfolio of (eligible) RES-E assets to cover for forecast error risk • Will likely impose the additional cost on RFNBO operator
RFNBO operator	• Exposed to risk both on supply and demand side • Can try to avoid additional PPA cost by managing risk themselves (e.g. via energy traders)
Refinery	• Main risk is compliance cost (less green hydrogen obtained than expected) • Could potentially seek to manage demand from multiple suppliers

Source: Guidehouse

The compliance cost of the risk from forecasting error can be reduced if a day-ahead forecast is sufficient to prove temporal correlation for the RES-E assets contracted via PPAs. In that case, no additional compliance costs are incurred. On the other hand, a day-ahead requirement gives incentives for RES-E operators to systematically overestimate their forecast production (which would be compared against the cost of intraday adjustments). In case the day-ahead forecast is deemed insufficient, additional costs are incurred by the need to cover the forecast gap only from eligible (additional, temporal, or geographical) RES-E assets or accepting (partly) grey hydrogen production.

8.6.3.3 Efforts for auditors/administrations to examine evidence

Each year of the RFNBO operation, the auditors would have to examine the sourcing evidence provided by the RFNBO facility. The RFNBO plant would have to submit its own production profile (hourly) for the whole year with the volumes of RFNBO produced and corresponding energy flows. The auditors will compare this data to the electricity procurement details:

- **Additionality:** Proof of unsubsidised and new status for all RES-E sourced via PPA(s) and the wholesale market.
- **Temporal correlation:** For wholesale market sourcing, the specific hours in the past year (e.g. 2023) in which RES-E shares were above the national average of the 2 years prior (e.g. 2021 and 2022).
- This information is compared against the RFNBO plant production profile after subtracting for the production profile of the asset or assets contracted directly via a PPA.
- **Geographical correlation:** Proof that all the RES-E assets are in the same bidding zone.
- Finally, the auditors would determine if all volumes or a share of total production volumes qualify as RFNBOs.

8.6.4 Summary and learnings from this case study

This case study illustrates the use of green hydrogen (or RFNBOs in general) in an industrial setting. It has implications beyond the scope of the transport RFNBOs. Several key learnings that are of major importance to the DA at hand can be derived:

1. **Allowing sourcing from eligible RES-E assets (via GOs) can significantly reduce risk and increase viability for the RFNBO business case** for several reasons:
    - The lead times of contracted (PPA) RES-E assets might be too long, and a bridge solution for the gap period is needed.
    - RFNBO production cases can be better scaled (FLH, electrolyser sizing, or hydrogen storage) if general sourcing is allowed.
    - General sourcing from eligible RES-E assets is essential to avoid risk from forecast errors (deviation from forecast) unless day-ahead forecast is sufficient (see the following).
2. **Increasing requirements over time (or temporary exemptions from the requirements) might help alleviate many of the initial pains of this nascent market (i.e. risks, electrolyser sizing, and additional costs).** This concept has not been discussed in detail in the case study. However, most of the major risks described (e.g. additional compliance costs and the need for oversizing) can be significantly lowered if the full requirements are put in place from the start.
3. **A choice needs to be made between allowing for day-ahead forecasts or intraday forecasts as proof of temporal correlation for contracted PPA assets.** The day-ahead requirement helps to avoid the risk of forecast errors on RFNBO production volumes and lowers compliance costs. On the other hand, it might be subject to overestimation by RES-E producers (compared to the cost of intraday adjustments).
4. **Large-scale hydrogen storage can help increase the production volumes of RED II-compliant (green) hydrogen.** Albeit not directly relevant for the DA, hydrogen storage will be crucial for any industry-scale RFNBO produced from

intermittent RES-E. Storage can alleviate some of the need to produce hydrogen in the hours outside of RED II compliance.

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While conducting research for this project, the authors received stakeholder perspectives on the topic through discussions with the Dutch government, the German federal government, Transport & Environment, Bellona Foundation, TenneT, National Grid, Certiq, Bundesnetzagentur, Red Eléctrica de España, RECS International, Royal Dutch Shell, BP, Greenpeace, BDI, BOW, Air Products, and VDMA.

10. Annex: Long list of options to fulfil each RED II requirement

As described in Section 2.3, the project team compiled a long list of options to fulfil each RED II requirement, largely from literature and position papers (see Section 9) and from discussions with consortium experts. Based on these inputs, the project team conducted a high level examination of all options for each case, discussing their strengths and weaknesses. Options from the literature that clearly do not correspond to RED II requirements are mentioned, but not evaluated. The high level evaluation of the long list of options can be found in this Annex. Case 1 is not included here because it does not fall under the DA in contrast to Case 2 and 3. Therefore, it was not necessary to compile and rate regulatory options for Case 1.

The assessments presented in this Annex were made in the beginning of this project. These preliminary findings were refined afterwards—for instance, building on feedback in and after the Expert Group meeting and stakeholder event. Readers are therefore advised to refer to the main report regarding the project team's recommendations; this Annex is merely intended to create transparency about the options that were not investigated in detail.

10.1 Evaluation criteria

The project team has developed a set of assessment criteria by which the options to fulfil the RED II requirements can be evaluated. The criteria can be derived from the larger objectives of the regulations outlined in Section 2.2:

- Ensuring that the requirements outlined in the RED II are met effectively
- Introducing a methodology that is robust and applicable under different regulatory and market conditions and over longer periods of time
- Allowing for flexibility in the implementation for Member States and RFNBO producers
- Not obstructing the scale-up of RFNBO technologies as planned in the Commission's hydrogen strategy (European Commission, 2020)
- Keeping the administrative burden both for private and state players as small as possible

This list of criteria was presented at the kick-off meeting. With this first interim report, the project team presents a more precise definition of the criteria and discusses their importance. For every criterion, the project team describes a scale of attractiveness with three levels, with green meaning fully sufficient, no objections, or limited objections; yellow meaning acceptable or moderate objections; and red meaning insufficient or strong objections.

10.1.1 Effectiveness for RED II compliance

This criterion gives an indication of to what extent an option would fulfil the respective requirement laid out in RED II to define the renewable nature of RFNBOs:

- **Fully sufficient (green):** The option fully complies with the details of the requirement as defined in RED II (mostly Article 27 and Recital 90). There are no loopholes for operators or national regulators to bypass the regulation.
- **Acceptable (yellow):** The option, in essence, fulfils the requirement as defined in RED II. Some RED II provisions may be interpreted with some flexibility. There may be ways for operators or national regulators to implement this option in a way that could erode RED II compliance.
- **Insufficient (red):** The option does not provide compliance with the respective RED II requirement and may violate some RED II provisions. There may be easy ways for operators or national regulators to implement this option in a way that makes RED II compliance highly questionable.

10.1.2 Applicability across Member States

The regulations to fulfil RED II criteria must enable RFNBO producers and national regulators in all Member States to have their respective volumes counted towards RED II targets. This criteria evaluates to what extent the proposed options can warrant counting:

- **Fully sufficient (green):** The option can technically be implemented without major issues across the EU. The required data sources and documents are available from Union-wide platforms or via platforms that are very similar across Member States. The option does not lead to unintended effects in Member States with relatively high or low RES-E shares.
- **Acceptable (yellow):** The option can be implemented across the EU, but difficulties may arise in some Member States. Some required data sources and documents may be available only via national platforms that may not always be comparable between Member States. Special provisions may be needed for Member States with relatively high or low RES-E shares.
- **Insufficient (red):** The implementation of this option will be problematic in some Member States. Data and document availability need to be evaluated on a case-by-case basis in each Member State. The option may not work in Member States with relatively high or low RES-E shares.

10.1.3 Applicability in non-EEA countries

Most scenarios anticipate that significant amounts of RFNBOs consumed in Europe will be imported from outside the EU, e.g. North Africa or the Middle East (Global Alliance Powerfuels, 2020; Öko-Institut e.V., 2019). Therefore, the regulations discussed in this report must also be implementable in countries outside the EEA in order to create a level playing field for RFNBO producers in and outside of Europe, as is also noted by stakeholders (VDMA, 2020; Global Alliance Powerfuels, 2020). The evaluation criteria are as follows:

- **Fully sufficient (green):** The option can technically be implemented without major issues in most countries of the world. The required data sources and documents may be available from global platforms. The option does not lead to unintended effects in countries with relatively high or low RES-E shares.
- **Acceptable (yellow):** The option can be implemented globally, but difficulties may arise in some regions. Some required data sources and documents may be available only via national platforms that may not always be comparable globally. Special provisions may be needed for countries with relatively high or low RES-E shares.
- **Insufficient (red):** The implementation of this option will be problematic in some regions. Data and document availability need to be evaluated on a case-by-case basis in each country. The option may not work in countries with relatively high or low RES-E shares.

10.1.4 Economic burden for operators

Electricity is usually the largest cost component in RFNBO production. The regulatory options discussed in this report—targeted at regulating the energy input of RFNBOs—potentially has significant impacts on these costs. The Commission has recognised the importance of electricity-based fuels, such as RFNBOs, to support the EU's commitment to reach carbon neutrality by 2050 and has formulated corresponding targets to invest in the scale-up of these technologies (European Commission, 2020).

Options to fulfil RED II requirements must, therefore, aim to avoid any economic burden on operators that would significantly hinder the intended scale-up. However, even in a scenario without any such regulations, RFNBO production is not expected to be commercially viable in most applications under the current market conditions (Agora Energiewende, 2018). The Commission therefore foresees extensive support programmes for electricity-based fuels. The evaluation of regulatory options in this report is, therefore, not based on the question whether a policy would make RFNBO production commercially unviable (which it is anyway), but whether the additional costs through the policy (if any) are proportionate to the policy objectives outlined in Section 2.2. The evaluation criteria are as follows:

- **Fully sufficient (green):** The option would probably lead to no or only limited additional costs for economic operators compared to a scenario without the additional regulation under discussion.
- **Acceptable (yellow):** The option would probably lead to considerable additional costs for economic operators, yet not to a level that would be prohibitively high, taking into account expected public support programmes.
- **Insufficient (red):** The option would probably lead to additional costs for economic operators to an extent that RFNBO production would not be viable even with high expected public support.

10.1.5 Administrative burden

Any regulation to facilitate RFNBO production compliance with RED II requirements would create the need for monitoring, reporting, and verification. This requirement could lead to a disproportionate administrative burden, both for economic operators and the responsible public authorities. Again, the intended scale-up of RFNBO technologies could be hindered by this burden. Options must be evaluated for the effect they would have in this regard. In terms of RFNBO compliance verification, each facility could be required to pass an ex ante audit to verify the starting compliance (e.g. correct geography, procurement in place, etc.) and subsequently follow yearly (possibly automated) audits to demonstrate compliance for each kilowatt-hour procured in the time period. Significant RFNBO plant modifications (e.g. capacity expansion) could then require additional ex ante audits. The evaluation criteria are as follows:

- **Fully sufficient (green):** Compliance under this option can be verified using centrally available data and documents; the data and documents that need to be submitted by the economic operators can also be based on existing data and documents. Public authorities can use existing templates or processes.
- **Acceptable (yellow):** Economic operators need to compile most required data and documents to demonstrate compliance or new data or document types might need to be introduced to the market. Public authorities need to establish new existing templates or processes. The legal framework may need to be adapted.
- **Insufficient (red):** Economic operators would need to compile data and documents with a disproportionate volume or additional effort. Some new data or document types that do not exist might need to be introduced to the market. The responsible public authority may need to review mostly on a case-by-case basis. The legal framework may need to be adapted.

10.2 Case 2 – Direct connection

10.2.1 Timing of RES installation commissioning

Table 17 summarises the fulfilment options and their preliminary evaluation for **isolated direct connection** and **direct connection plus grid connection** subcases.

Table 18. Preliminary evaluation of options to fulfil the requirement as regards the timing of RES installation commissioning

Options to fulfil requirement:	Effectiveness for RED II compliance	Applicability across Member States	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
Via commissioning date					
Via construction permit issuing date					
Via lack of grid connection					

For **isolated direct connection** subcases, this requirement might not need to be examined (i.e. synchronisation could be demonstrated via lack of grid connection given that without an off-taker it is physically impossible for the RES installation to come into operation in an island situation, the RFNBO facility and the RES installation are dependent on each other). Therefore, the operator's economic interest alone should be sufficient to promote a synchronised commissioning of both facilities. However, the case where an RFNBO installation is connected to old RES installations, which are disconnected from the grid, would remain undetected. RED II compliance in this case is low, and this option should not be pursued.

Instead, the project team identified two straightforward fulfilment options to check whether the RES installation comes into operation after or at the same time as the RFNBO installation. They can applied for both **isolated direct connection** and **direct connection plus grid connection** subcases. One option would be to examine the commissioning dates of both the RFNBO and RES installation. Plant operators could provide their operating licences as proof to the regulatory authority. Alternatively, instead of the commissioning date, the construction permit date can be used.

For both cases, the evaluation criteria regarding applicability and regulatory burden are identical and entirely unproblematic. The commissioning date and construction permit issuing date are already available to the administrations. On a similar note, in both EU Member States and non-EEA countries, industrial installations, such as RFNBO facilities or larger RES installations, have to go through a certified commissioning process before being allowed to come into operation.

The evaluations of the two options, however, differ on the effectiveness criteria for RED II compliance and economic burden. Given the explicit RED II requirements regarding the timing of RES installation commissioning, demonstrating synchronisation via the commissioning date would be most compliant with the RED II. However, such a strict interpretation of this requirement might lead to adverse effects. It was objected during stakeholder interviews, as even with proper project planning, there is a significant risk of a temporal mismatch between the two commissioning dates of the facilities. Potential causes are different technologies, lead times, readiness levels, permitting procedures, etc. Therefore, a switch of the sequence of the commissioning dates might occur even though originally the RES installation was meant to come into operation simultaneously with the RFNBO installation. In this case, the RFNBO producer would lose the option to claim 100%

RES-E unless the start of operation of the renewable installation is put on hold. This in turn would create economic damage due to foregone revenue.

Another fulfilment option consists in checking the adherence of the original construction permit issuing dates. In the case of a delay of the RFNBO operation start, this would lead to limited RED II compliance. On the other hand, it might reduce the mentioned risk caused by temporal mismatch and facilitate faster deployment of RFNBO facilities.

Moreover, a small modification of the commissioning date fulfilment option could also mitigate this risk. Instead of evaluating the commissioning date on the level of a calendar date, it would only have to match on a monthly or even yearly level. In particular, the latter option would provide quite a bit of additional flexibility to operators and reduce the economic burden caused by the risk of a temporal mismatch. An approach of increasing requirements over time could be adopted here, starting by requiring the matching on a quarterly level and then raising it to the same calendar date once RFNBO project developers gained more experience with synchronised project pipelines. Evaluating RED II compliance for this option still requires a legal review at this point in time.

Recommendation
For both **isolated direct connection** and **direct connection plus grid connection** subcases, verify the timing requirements of the RES and RFNBO installation commissioning by checking the commissioning dates of both assets. The project team further recommends starting by solely requiring matching on the level of a calendar date and increasing the requirement to a duration of 3 months later. If the RES-E asset is commissioned even later, no RFNBO production is possible under Case 2.

10.2.2 Supply exclusively via direct connection

The second requirement of the RED II for Case 2—electricity sourced from direct connection to a renewable installation—regards sourcing the supplied electricity. RED II requires that the RFNBO production facility must exclusively be supplied by a RES installation via direct connection, and no additional electricity should be taken from the grid.[98] Table 18 summarises the fulfilment options and their preliminary evaluation for the **isolated direct connection** and **direct connection plus grid connection** subcases.

[98] This requirement does not prevent combined cases. Instead, it solely regards the requirements to be fulfilled in order to claim a 100% RES-E share via the fulfilment options of Case 2.

Table 19: Preliminary evaluation of options to fulfil the requirement as regards the supply exclusively via direct connection

Options to fulfil requirement:	Effectiveness for RED II compliance	Applicability across Member States	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
Proof of isolated direct connection					
Consumption and supply smart metering					
Full load hour estimation during commissioning process					

10.2.2.1 Isolated direct connection

If the RES installation is not connected to the grid, the installation producing the RFNBO and the RES installation can be seen as an integrated, isolated unit with the two installations being linked via a direct connection (e.g. an island situation). By providing evidence that the RES installation is directly connected to the RFNBO facility and not connected to the electricity grid, the RFNBO producer directly proves that their facility is exclusively sourced by said RES installation and that no additional electricity is taken from the grid. The only sensible fulfilment option in this subcase is the demonstration directly within the commissioning process.

This fulfilment option is straightforward. During the usual commissioning process of the RFNBO facility, the certification body verifies the existence of a direct connection linking the RFNBO facility to a RES installation. Additionally, it has to check that neither the RFNBO nor the RES installation disposes of a grid connection. Sourcing from the grid is therefore not possible. According to the project team's preliminary assessment, the implementation of such an updated commissioning process does not pose significant obstacles. This fulfilment option appears to be particularly advantageous regarding the administrative and economic burden. While the certification body would have to slightly adapt their procedures, the claim of a 100% RES-E share could be certified for the entire lifetime of the facility or at least until the standard operation of the facilities change.

In consequence, applicability across Member States and non-EEA countries appears unproblematic. However, the certify-and-forget design of this fulfilment option that comes without a continuous stream of documentation makes it potentially more susceptible to fraudulent activities as there might be no regular verification that the originally certified operating mode is still in place. Periodic inspections of the operating mode of the RFNBO and connected RES installation might, therefore, be required.

10.2.2.2 Direct connection plus grid connection

The main fulfilment option to ensure that the RFNBO facility is exclusively supplied via direct connection consists of using smart metering (covering energy and power output and input) installed at the RES-E and the RFNBO installation. This method is currently common practice for large-scale RES installations that participate directly on the wholesale markets and for all RFNBO facilities. The granularity of the temporal correlation is critical to determine that the electricity sourced is of renewable origin. Evidently, the higher the temporal resolution, the more accurate this verification option will be and the higher the effectiveness for RED II compliance. A 15 minute resolution, which corresponds to the electricity contracts traded on the European Power Exchange, appears appropriate to ensure that there is no grid consumption. Lower resolutions (i.e. hourly) would not necessarily reduce the economic burden for operators because for its residual consumption, the RFNBO producer has to rely on the Case 3 fulfilment option anyways.

The process of providing evidence would look as follows: The smart meters deliver the time-series data to the certification body. The data can be delivered either in real time or in batches, as long as the delivery is automated in some form to reduce the administrative burden. The certification body, in turn, verifies the supply and demand matching for each RFNBO producer that intends to claim a 100% RES-E share via the Case 2 methodology. Given the data, such a solution in any case would require deploying dedicated software on the administrative side. Implementing such a system might raise difficulties for some administrations. The applicability in non-EEA countries might be more challenging than other fulfilment options. However, once implemented, this fulfilment option would run mostly on an automated basis and could reduce the administrative burden. Regarding the economic burden for the operators, capturing real-time power consumption and supply data is already the default technology level for most industrial facilities.

Alternatively, a rough FLH estimation of the amount of energy that is delivered to the RFNBO facility via direct connection could serve as a fulfilment option that is easy to implement. The FLH estimation could be carried out by the commissioning authority. Then, a simple comparison of the yearly supply and demand would suffice. However, the project team recommends discarding this option as it does not seem to comply with RED II requirements. In fact, under this option the temporal correlation between the RFNBO consumption and RES installation generation is in no way determined. Therefore, the RFNBO facility would most likely consume electricity in times when the RES installation does not generate electricity.

Recommendation

- For **isolated direct connection** subcases, the certification body could verify the existence of a direct connection linking the RFNBO facility to a RES installation and the non-existence of a grid connection to determine that RFNBO production is exclusively supplied via the direct connection.
- For **direct connection plus grid connection** subcases, the project team recommends verifying that time-series data matches the RFNBO consumption and linked RES-E generation obtained via smart metering. The temporal correlation should be resolved in blocks of 15 minutes or less.

10.3 Case 3 – Renewable grid electricity

10.3.1 Renewable electricity sourcing

RES-E sourcing is a regular practice amongst a variety of economic players, and GOs and PPAs are common instruments used for that purpose. Hence, general RES-E sourcing of can be achieved via these instruments.

A key advantage of PPA over direct, self-investment for (possibly onsite) RES-E generation is the lack of CAPEX requirements, a purchasing entity thus only has OPEX associated with RES-E. PPAs might even be a possibility of onsite generation projects if the purchasing entity is not willing to invest or bear the risk associated with the generating asset. As noted previously, the price of the PPA is negotiated between the contractual parties, which offers a possibility to strike below wholesale market prices[99]—an important factor for RFNBO operators that are highly sensitive to electricity prices.[100] In the PPA setup, GOs serve as the proof that the purchased electricity is renewable but are included in the negotiated PPA price. This setup is in contrast to standalone GO purchase (hence not a PPA and GO combination), which will always be priced above the wholesale market (wholesale market price plus the cost of the GO) by nature.

There may be some countries where there are no GOs, RECs, or I-RECs in place. In these cases, it would be debatable whether only PPAs would be sufficient to fulfil this requirement. In practice however, closing a PPA in these countries may not be possible due to a lack of third-party access to electricity grids. Therefore, direct-wire self-generation may be a more practical production model (see Section 5).

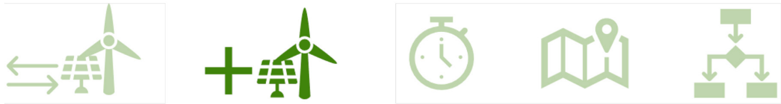
To fulfil the simple requirement of sourcing any RES-E from the grid, standalone GOs, a combination of PPAs and GOs, and any of variations (e.g. virtual or physical PPA, GOplus, GO^2) should therefore suffice (VDMA, 2020; Energy Technologies Europe; Shell, 2020; Global Alliance Powerfuels, 2020).

Recommendation
Any RES-E GO, PPA and GO, or variations thereof, should formally be sufficient to claim the sourcing of RES-E for RFNBO production. As expected by RED II, however, “other appropriate criteria” are needed to ensure the renewable nature of RFNBO energy content.

[99] The price of the PPA will typically be calculated on the levelised cost of the generating asset, the developer’s margin, and cost of balancing. The contract might include price floors (e.g. LCOE and minimum acceptable margin) and price ceilings (e.g. wholesale price and acceptable, to all contracted parties, premiums for renewable electricity). PPA parties can agree on such a floating price. With a fixed price, there is zero uncertainty. With a floating price, the seller can still benefit—to a limited extent—from rising wholesale prices, and the buyer can still benefit—to a limited extent—from falling wholesale prices.

[100] Generally, the PPA prices can be pushed below wholesale prices in times of RES-E project oversupply.

10.3.2 Additionality



10.3.2.1 Deployment additionality

A number of fulfilment options exists for deployment additionality. Some of them are not compliant with RED II requirements but are discussed here as they have been brought forward by industry stakeholders. Regarding these options, RES-E assets can be classified by:

- Deployment date:
    - RES-E assets that are **new** relative to the commissioning date of the RFNBO asset, which could be defined as in Case 2 (see Section 5.2.1)—e.g. RES-E assets were commissioned the same quarter as the RFNBO asset or later. On the other hand, RED II does not give as strict prescriptions as in Case 2 when it comes to this timing. Therefore, this definition could be broadened to RES-E assets that have been deployed 2 years or less before the commissioning of the RFNBO asset. This definition would allow RES-E production for the electricity market should there be delays in the construction of the RFNBO plant.
    - RES-E assets that are **existing** are those that have been deployed before the cut-off date determined above for new RES-E assets.
- Public support:
    - RES-E assets that were, are, or will be **subsidised** with public money. For the purposes of this document, a subsidy is defined as contribution to the RES-E asset from public finances (e.g. investment support, feed-in tariffs, etc.).
    - RES-E assets that are **unsubsidised** are those that have never received any direct capital or operational support. This definition excludes indirect forms of public support, such as free grid connection or below market rate land lease or sale.

Another important element of additionality is the counterfactual scenario—most importantly, whether the RES-E would have still been generated and consumed elsewhere in the absence of the RFNBO facility (Cerulogy, 2019). In the following section, the project team examines fulfilment options by which economic operators can comply with the requirement of deployment additionality. Their assessment is summarised in Table 19.

Table 20. Preliminary evaluation of options to fulfil the requirement of deployment additionality

Options to fulfil requirement	Effectiveness for RED II compliance	Applicability across MS	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
RES-E from new, unsubsidised assets					
RES-E from existing, formerly subsidised assets					
RES-E from existing, unsubs. assets					
RES-E from new, subsidised assets					
Automatic additionality in countries with only renewable capacity additions					

Sourcing RES-E from new, unsubsidised assets

As long as there is no true price parity between wholesale electricity and RES-E prices, any new and unsubsidised RES-E project would rely on additional income streams from their off-takers to be realised. Therefore, this option would provide a strong additionality element (Cerulogy, 2019; Global Alliance Powerfuels, 2020; Öko-Institut e.V., 2017; Ørsted, 2020).

The concept would have to be implemented via a mechanism that would track whether subsidies have been granted to the RES-E generators and also provide a time stamp (for both the commissioning of the RES-E asset and generated power). Existing mechanisms, such as GOs, could be readily employed for such purposes across Member States. Similarly, I-RECs will also track both such datapoints, while certain RECs (e.g. in the US) do not provide transparency on the subsidy topic. As with the previous options, the administrative burden here is going to be low in case standard GOs are used but more complex if novel concepts such as GO-plus are preferred (see Section 6.2.1). PPAs with new, unsubsidised RES-E assets could also be vehicles to fulfil this option. To avoid double counting RES-E credits, PPAs would need to be combined with a bundled GO purchase from that RES-E installation.

This option would create some economic burden for RFNBO operators as they would be required to pay a premium for their electricity in order to close the expected revenue gap between the RES-E asset and wholesale electricity prices. However, depending on the implementation vehicle, different effects must be considered. PPAs with RFNBOs operators can potentially be less bankable given the relatively less secure RFNBO market in comparison to more standard utilities or large corporate purchasers (Cerulogy, 2019). On the other hand, a potential issue with the standalone GO-plus market is that, whereas a PPA can be secured before project development, GO-plus can only be issued when the RES-E plant becomes operational and are, thus, more exposed to market volatility.[101] These factors might increase the cost of capital for RES-E producers and therefore, also increase the effective power price for RFNBO producers. Pooling these risks through the vehicles of private or public deployment funds for RES-E generation may be a way to limit the resulting price premiums (see Section 6.2.3).

Sourcing RES-E from existing, formerly subsidised assets

This method could apply to any RES-E facility, of any age, depreciated or not, that has been supported by public money in development or operation. Such an approach can easily be applied across Member States (e.g. via GOs) and even non-EEA countries (e.g. via RECs, I-RECs, or PPAs).

In general, such RES-E assets would not fulfil the additionality requirement. However, with many existing RES-E assets already or soon to be falling out of subsidy schemes, a case could be made for their eligibility in specific circumstances. Such assets could, for instance, claim that continuous operation is no longer viable in the absence of subsidy payments and that a direct contract (e.g. via PPA) could prevent them from ceasing operation (VDMA, 2020). The economic non-viability of continuing operation could be caused by situations when replacement expenditures (REPEX, e.g. repowering), OPEX, and target margins would create a net negative cash flow when assuming expected wholesale market prices that the RES-E would standardly get.

The proof of such claims could be obtained on a case-by-case basis (for instance, via a PLA) to judge whether the PPA with the RFNBO producer is a crucial factor in prolonging the asset's lifetime. This need could be demonstrated by showing net negative cash flows vis-à-vis wholesale market prices and net positive cash flows vis-à-vis the PPA with the RFNBO producer. Therefore, an additionality claim could be made for RES-E assets that would demonstrably plan to cease operations and where a contract with an RFNBO producer would prevent them from doing so. In general, continuing operation of such RES-E assets (i.e. where economic viability of operation is shorter than technical lifetime) is desirable. A key risk, however, is that under such an option, the additionality requirement is significantly reduced and does not trigger additional RES-E generation (e.g. via loose interpretation of the PLA by Member States).

Sourcing RES-E from existing, unsubsidised assets

This approach could be readily applied across Member States via GOs, which track whether subsidies have been granted to the RES-E generators by default. Similarly, I-RECs will also track that information while certain RECs (e.g. in the US) do not provide transparency on the subsidy topic. In regions where no applicable GOs exist, a PPA with an existing, unsubsidised RES-E installation may be sufficient to prove compliance. Given the existence of these mechanisms, the possible administrative burden of this option is likely to be low. There is also low economic burden—a large oversupply of GOs on the current market causes their low price. Conversely, this low cost also means that such sourcing via GOs has only a weak additionality element as the additional (i.e. GO price) financing obtained from RFNBO producers is marginal.

Furthermore, there is a risk that GOs might not reflect all of the subsidies that the RES-E installation has received over its lifetime. RED II Article 19.7(d) states that a GO should

[101] Certain RES-E plants can have very long lead times, which is particularly true for offshore wind developments. PPAs could, therefore, help secure and speed up these processes better than standalone GOs or GO-pluses.

specify at least “whether and to what extent the installation has benefited from investment support, whether and to what extent the unit of energy has benefited in any other way from a national support scheme.” This specification seems to imply that if an asset receives only support per kilowatt-hour (i.e. a feed-in-tariff or premium), GOs for energy volumes that are produced after the asset ceases to receive a feed-in-tariff would be marked as unsubsidised. In practice, some RES-E assets under this option would, in fact, fall under the previous option (sourcing RES-E from existing, formerly subsidised assets).

The main disadvantage of this option is that it would open the door for non-additional, older projects that are not receiving governmental support, such as old hydropower projects (Cerulogy, 2019). Thus, this second option cannot guarantee any additionally element under the RED II requirements and is not recommended for further evaluation.

Sourcing RES-E from new, subsidised assets

A typical example of such an asset is a newly deployed RES-E facility that has been supported by public support schemes to reach a Member State’s renewable energy targets. As with the other options, there is a strong applicability across Member States. It also has strong applicability internationally as GOs, RECs, and I-RECs contain the information about the newness of a facility by default (date of asset commissioning). Similar to the options above, the administrative burden of this option is likely to be low. The economic burden on operators would also likely be low given the rapid growth of new installations of RES-E generation in the EU (thus, oversupply of GOs) and the expected, limited RFNBO production in comparison (thus, limited demand).

However, RFNBO operators would likely not add to RES-E financing or deployment under this option. The counterfactual here is that a RES-E asset would be subsidised but not receive any financing from RFNBO operators. RES-E support schemes (e.g. auctions) are generally designed so that the support payments cover the financial gap to allow for economic operation. Additional RFNBO financing would, therefore, only lower the amount of public financing required for the auction-winning bids and not directly trigger additional RES-E capacities being deployed. There is a mere possibility that resulting cost savings for the support scheme might be used to contract additional generating assets. There is, however, no guarantee for such outcome, and it might have to be organised or required on the Member State level. In sum, this option does, therefore, not guarantee a strong additionality element and is not recommended for further evaluation.

Automatic additionality in specific countries

An alternative, additional option could be to allow for automatic additionality in countries where it can be expected that all new capacity additions will be renewable with reasonable certainty. The basic logic of this option is that the electricity demand from RFNBO producers will automatically trigger additional demand for capacity additions on the market. If these capacity additions are only renewable (e.g. due to price advantage or bans on new fossil generation), the RFNBO operator could be preapproved for additionality. However, there are at least two main considerations that might undercut the basic logic of this option.

First, many fossil generators, especially coal, currently run on low capacity factors due to lower marginal costs and priority RES-E dispatch. Additional electricity demand from RFNBO production would thus unlikely need additional RES-E capacity but would increase the load factor of underused fossil generators. Second, a similar argument can be made for retiring fossil-based generators, which could be delayed by accommodating the additional demand from RFNBO production instead of RES-E capacity additions.

As such, this concept is unlikely to fulfil the RED II additionality requirements. Moreover, while this concept might be generally well-applicable across Member States (due to the transparency of the National Energy and Climate Plans), its applicability (and verifiability) might be questionable for non-EEA countries. Therefore, this option is not recommended for further evaluation.

Recommendation

Sourcing RES-E exclusively from new and unsubsidised assets seems to be the most suitable option to define deployment additionality as expected in Recital 90. The economic burden this sourcing would place on RFNBO production, howeverc, needs to be examined. Also, sourcing from old, previously subsidised assets that would cease operations in the absence of a contract with RFNBO operators could also be considered as additional and is recommended to be examined further.

10.3.2.2 Surplus electricity

The question discussed in this subsection is how RFNBO producers can prove that a unit of electricity they have consumed was renewable and would have been curtailed if they had not used it. This goal is not trivial to achieve as it involves a hypothetical counterfactual that assumes no RFNBO production. Table 20 shows a list of options that are conceivable, explained in more detail. Differing from such tables in other subsections, the assessment criterion of effectiveness for RED II compliance has been removed since surplus electricity is not explicitly mentioned in RED II. Instead, options are evaluated regarding effectiveness for ensuring additionality.

Table 21. Preliminary evaluation of options to fulfil the requirement of surplus electricity

Options to fulfil requirement	Effectiveness for ensuring additionality	Applicability across MS	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
Negative spot market prices					
Hours with actual RES-E curtailment					
Ex-post modelling					

One option to fulfil the requirement of surplus electricity is to **count electricity consumed in times of negative spot market prices as additional.** Negative spot market prices arise when there is a forecast systemwide oversupply of electricity. RES-E units that are flexible enough and receive market-oriented remuneration plan to cease generation in these hours to avoid the negative prices (**economic curtailment**). If an RFNBO producer adds their load to the system, the generation unit with the lowest marginal costs will cover the increased load—most likely, a renewable plant that would otherwise be curtailed. Adding the load would typically be possible on the day-ahead market up to 1 hour before the time of delivery, after which the market closes. This option, therefore, could be a way to achieve additionality. Another advantage of this option is that the required data—spot market prices—is public and can easily be obtained from electricity exchanges (e.g. EEX in the EU). On the other hand, many countries outside Europe have not yet introduced (spot) markets in the electricity sector (World Bank, 2018). This option would consequently not be applicable in these countries as long as they have not implemented electricity spot markets.

Another option would be to **count electricity as renewable and additional in times of TSO-scheduled RES-E curtailment.** Typically, 1 hour before the time of delivery, the spot market closes and the TSO takes responsibility for matching supply and demand. TSOs have variety of tools to match supply and demand, including physical curtailment of renewables. Instead of this scheduled curtailment, TSOs could use RFNBO plants as an upwards method of demand side management and tell the operators to increase their demand and prevent curtailment. If there was no RFNBO production in such hours, it is therefore likely that more RES-E would be curtailed because any flexible thermal generation is usually curtailed before RES-E due to higher marginal costs or priority dispatch. RFNBO production, therefore, enables RES-E production that would be curtailed in its absence, making these energy volumes additional. The hourly volume of RES-E curtailment would probably need to be reported by TSOs, potentially creating some administrative burden in reporting and monitoring.

Assuming that RFNBO production reaches gigawatt-scale, as envisioned in the Commission's hydrogen strategy (European Commission, 2020), RFNBOs could, at some points in time, make up a significant share of the total system load. In these hours, RFNBO production might use some RES-E that would, in its absence, be curtailed even though spot prices are positive and no RES-E is curtailed in reality. **Ex post modelling** could prove this and encourage RFNBO producers to demonstrate the additionality of their consumed electricity. However, this demonstration would require fairly complex power market modelling, including the possibility of surplus RES-E being sent to distant load centres. Most likely, this modelling would need to be performed by TSOs. Especially in some third countries, this method could create difficulties due to a lower availability of power system models than in Europe. As such, this option is not recommended for further evaluation due to its complexity.

Regarding economic burden, all options are rated green as they do not create any additional costs compared to a scenario where no such regulation on surplus electricity exists (see Section 10.1.4 for details on the rating methodology). This lack of regulation is because no RFNBO producer is obliged to use surplus electricity and comply with these options; they are, rather, an optional way to avoid the more strict deployment additionality requirement, at least for parts of the energy consumed (see Section 10.3.2.1). Negative market prices specifically are a valuable market signal, showing that fossil producers are willing to pay money to stay online. They also give a price signal to flexibility providers that system flexibility is required. RFNBO producers are a type of flexibility provider, but by this provision, they might get an advantage compared to other flexibility options (e.g. direct electrification).

Recommendation
Using surplus RES-E could exempt those energy volumes from compliance with the deployment additionality requirements. Hours with negative spot market prices or with RES-E curtailment could be acknowledged as hours with surplus renewable electricity.

10.3.2.3 Target additionality

Besides additionality at the level of RFNBOs producers, as discussed previously, additionality at the RES target level should also be ensured. Two steps are necessary:

1. A baseline must be determined that identifies how much RES-E would be used in the absence of RFNBOs—respectively, how much RES-E must be available for consumption in 2030 to meet the RES target.
2. The electricity used to produce the RFNBOs must be related to the baseline to ensure that a Member State's RES target is not met with the electricity used for the production of RFNBOs.

Besides the default option given by the legislation in RED II, two other options were identified to foster RES generation for RFNBO production that is truly additional on the target level:

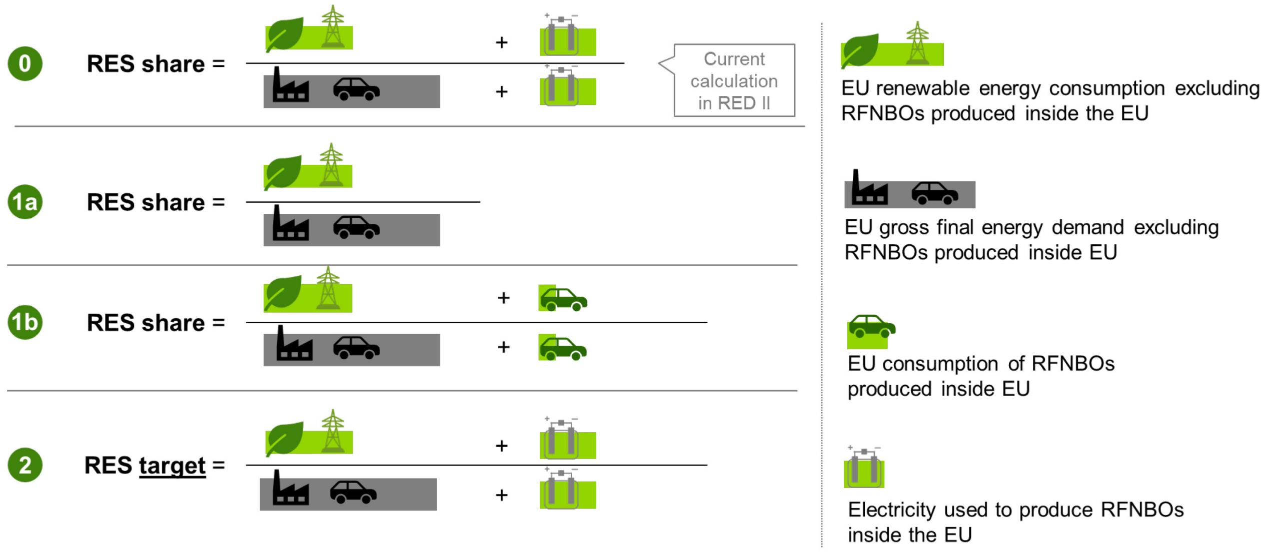
- **Option 0:** Deviation from the baseline is considered ex post based on current legislation. Electricity consumption for domestic RFNBO production is included in the overall RES target but, in this case, not the energy content of the RFNBOs (see Figure 22, 0).
- **Option 1:** Deviation from the baseline is considered ex post based on an approach differing from the current legislation, with the following sub-options.
    a. RES-E used to produce RFNBOs is considered neither in the numerator nor in the denominator when calculating RES share (see Figure 22, 1 a).
    b. This option is the same as Option 1a, but the RFNBO final energy consumption is included in the calculation so that RFNBO production is not completely excluded from the RES target calculation (see Figure 22, 1b).
- **Option 2:** Deviation from the baseline is considered ex ante via adjusting EU-wide and national RES targets by including projected RES-E consumption of RFNBO production in RES targets (see Figure 22, 2).

The different options are described in more detail in the following paragraphs.

Option 0: Default ex post approach

This option reflects the current regulation given by RED II, which states in Article 7 that the energy content of RFNBOs is included in the overall RES target only if it is not produced by a Member State from domestic RES-E. In turn, RES-E for domestic RFBNO production is included in the overall RES target but not the energy content of domestically produced RFNBOs. Imported RFNBOs are taken into account in the RES target based on the final energy they carry while, for domestically produced RFNBOs, the RES-E input is considered. This form of measuring target achievement bears a high risk that target additionality will not be achieved, as the electricity used to generate the RFNBOs is fully counted towards the RES target.

Figure 22: Options to foster target additionality



Source: Guidehouse

Option 1: Alternative ex-post approaches

The alternative ex post option means that the verification of target additionality is still based on empirical data. In other words, in 2030, it will be measured on the basis of empirical data whether target additionality has been achieved or not. However, the additionality of RES-E used to produce RFNBOs is addressed in a stricter way. Given the methodology for calculating the share of renewable energies in gross final energy consumption set out in Red II Article 7, this method would result in an adjustment of the numerator and the denominator. The two sub-options outlined previously, for which additional data has to be collected in addition to the data anyway collected to verify the achievement of the target, are applicable. In Option 1a, the renewable electricity used to produce the RFNBOs will not count towards RES target achievement, meaning that the electricity used to produce RFNBOs must be measured and the values must be reported to the responsible authority. Under Option 1b, in addition to the data for Option 1a, data on the quantities of RFNBOs produced must also be reported to the regulator. There are two ways to measure the electricity used for RFNBO production or to measure RFNBO production:

- **Electricity meters at the plant:** All plants could be equipped with electricity meters that measure and report electricity consumption. Reporting obligations are imposed on the operator, and the regulatory authority must determine the correct application and reporting by operators. On the one hand, the meters can be used to measure the electricity and thus be useful for Option 1a, but conversion factors (either default or provided by the producer) can also be used to estimate the amount of RFNBOs produced, which could also be used to implement Option 1b. Electricity meters are likely already installed in the plants, so the additional cost should be limited.
- **Monitoring the quantity of RFNBO produced:** Monitoring the RFNBO quantities is relevant for Option 1b. On the other hand, the quantity of RFNBOs can also provide information via conversion factors about the electricity input, which is, in turn, necessary for both options. Due to monitoring RFNBO quantities for the energy tax and for calculating the RES-T target, it is likely that the produced quantity of RFNBOs will be tracked anyway, so this option would lead to low additional costs.

The biggest advantage of an ex post measurement of the baseline and the electricity consumed by RFNBO production is the accuracy of the measurement. Only errors in the official statistics or errors in measurement lead to inaccuracies. Furthermore, ex post measurement is, from a data and calculation perspective, relatively simple to implement as most data has to be collected and reported anyway. Provided that deployment additionality is facilitated, these ex post options lead to a precise and certain achievement of target additionality. If deployment additionality is not given, however, the Member State has little reliable information available during the period up to 2030 to properly plan the necessary renewable electricity generation capacities. In this case, it would be necessary to monitor how many RFNBOs were produced and how much electricity was used each year in order to ensure the right deployment of renewable energies. Otherwise, Member States that have successfully met their initial renewable energy targets could miss their targets if significantly more RFNBOs were produced than predicted.

Not taking into account the RES-E consumption for the RES target would require legal provisions at EU level. Hence, it cannot be part of the DA but would have to be carried out through RED II adjustments.

Option 2: Ex ante approach

Option 2 is an ex ante target setting based on electricity consumption forecasts and the expected electricity consumption for RFNBO production. As Figure 22 shows, this option adds, without the electricity consumption for RFNBO production, the electricity consumption of the predicted RFNBO production in the numerator and denominator to the RES target, automatically increasing it. The 32% target at the EU level would be increased by the predicted electricity consumption for RFNBO production and would lead to a share that is greater than 32%. Such a calculation requires the expected renewable shares—more precisely, the values of the numerator and the denominator and the expected RES-E demand—to produce RFNBOs in 2030. Potential sources for an ex ante assessment of RES-E generation in 2030 are the following:

- **NECPs:** The NECPs provide several advantages. They are available for all Member States for the period under consideration and are designed in a comparable way due to the requirements. Furthermore, they provide projections for RES-E generation and energy demand and were prepared in the context of RED II. The expected electricity used to produce the RFNBOs in 2030 could, in contrast, be difficult to quantify. Although this is not always available in the NECP documents, the data behind them should be able to show this amount of RES-E. To determine that target additionality is not only achieved on the basis of the forecast, an update of the forecasts during the period to 2030 would be a useful option. It is also unclear to what extent further measures that have been implemented to increase RES deployment in the meantime are fully taken into account in the NECPs.
- **EUCO Scenarios:** In addition to the NECPs, the EUCO scenarios, which model the climate and energy targets of the EU based on the PRIMES model, also represent an alternative for the renewable electricity projection data. The same advantages and disadvantages apply to these scenarios as to the NECPs, but the NECPs may better reflect national characteristics than the EUCO scenarios. On the other hand, the EUCO scenarios are based on a uniform database, which could be an advantage.
- **Other national scenarios:** National scenarios other than those in the NECPs also represent an alternative but are less suitable in terms of comparability between the Member States than the NECPs or the EUCO scenarios.

Forecasts of electricity demand by RFNBO production is a major challenge. First and foremost, whether the current NECPs (or EUCO Scenarios) can be used for this purpose must be clarified. If new supporting policies for RFNBOs are implemented, which were not anticipated in the NECPs or the EUCO scenarios, the NECPs and EUCO scenarios may underestimate the electricity demand from the production. A new modelling would have to be carried out to take these new policies into account. The NECPs would have to be examined to determine how much RFNBOs will be produced in each Member State in 2030. The amount of electricity needed for this production would have to be estimated and then deducted from the amount of renewable electricity expected in the NECPs. In total, this process is complex and involves great uncertainty. In some cases, this process alone would mean that some Member States would not meet their RES targets with the figures presented in the NECPs. Should a new modelling become necessary due to new policies, it remains to be discussed whether the amount of electricity that flows into RFNBO production in the NECPs should be counted to the baseline, and thus only the additional RFNBO production should not be counted, or whether all RFNBO production should be excluded from the baseline.

The main advantage of an ex ante determination is that the Member States have planning certainty regarding the RES-E share to be achieved in 2030 and a precise development path. According to the VDMA (2020), the pace of increasing the share of renewable energies in the EU Member States is too slow to meet the additionality requirement because the expansion of renewable energies is progressing far too slowly compared to the necessary conversion of many sectors to electricity or other renewable energies. In order to ensure that the pace of increasing installed renewable capacity does not slow down the transition to renewable energy in these sectors, such forecasts can be of high importance and enable appropriate planning. The main challenges of this option are, on the other hand, a higher degree of inaccuracy compared to the ex post determination and the high uncertainty regarding the RFNBO forecasts. To reduce these inaccuracies and uncertainties, a continuous update of the forecasts might be helpful to keep the deviations small. Who should be in charge of these ongoing updates needs to be clarified. If the NECPs are used as a source, it seems that the individual Member States are the only option, in order to ensure consistency between the starting point and the subsequent modelling rounds.

Evaluation of options

In the following, the options are assessed against a set of evaluation criteria similar to the one described in Section 10.1. However, the criterion of effectiveness for RED II compliance does not apply here, as RED II does not provide any provision for target additionality. Instead, the criterion of effectiveness for target level additionality is considered, which gives an indication of the probability to achieve additionality at the target level. The evaluation criteria are as follows:

- **Fully sufficient (green):** There is high certainty that the option will lead to full additionality on the target level.
- **Acceptable (yellow):** There is moderate uncertainty that the option will lead to full additionality on the target level, but regular planning updates can help facilitate additionality.
- **Insufficient (red):** There is high uncertainty whether the option will lead to any additionality on the target level or not.

Table 21 summarises the evaluation for each option.

Option 0 (Default ex post approach):

- **Effectiveness for target level additionality:** An ex post assessment based on the current legislation allows for an exact measurement of the impact. However, the inclusion of electricity consumption for RFNBO production in the numerator and the denominator means that only 32% of additional electricity consumption is renewable on the EU target level for 2030. Any required deployment additionality will imply that the RES share for all other uses might actually be lower than 32%, making the effectiveness of target level additionality is insufficient.

- **Applicability across Member States:** As this option is based on the current legislation, no additional data provision necessary. The option can be implemented without any issue across the EU.
- **Applicability in non-EEA countries:** This option does not anticipate any additional provisions on the level of RES targets. Therefore, this option does not imply that the EU has to impose additional conditions on other countries' targets. However, target additionality can be a major issue in non-EEA countries, as they may tend to feed-in RES-E into the production of RFNBOs to be exported. The limited effectiveness of this option, with respect to target additionality, will apply to non-EEA countries as well.
- **Economic burden for operators:** As the option is based on the current regulation, no additional economic burden for operators will occur.
- **Administrative burden:** Assessing target additionality under this option is simple, given that no requirements beyond the current regulation is imposed. In particular, no change to RED II is required.

Table 22. Preliminary evaluation of options to fulfil the requirement of target additionality

Options to fulfil requirement	Effectiveness for target level additionality	Applicability across MS	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
Ex post: RES-E for RFNBOs counts towards target (default)					
Ex post: RES-E for RFNBOs does not count towards target					
Ex post: RFNBO energy content counts towards target					
Ex ante: Increase RES-E target					

Option 1 (Alternative ex-post approaches):

- **Effectiveness for target level additionality:** This option leads to an exact measurement of the additionality for RFNBO production given the definition of additionality (Option 1a or Option 1b). It also leads to exact measurements under the assumption that the renewable targets of the Member States and at EU level could be adjusted depending on the electricity demand of RFNBO production or the amount of RFNBO production in 2030. In addition to accurate measurement, Option 1a also ensures full target additionality, provided that deployment additionality is required as RFNBOs do not show up anywhere in the calculation of the overall RES share. For Option 1b, the energy content of RFNBOs enters both in the numerator and denominator, which means target additionality only for the conversion losses during the RFNBO production.

- **Applicability across Member States:** The option can technically be implemented without major issues across the EU. The figures for RES-E production have been collected for years in all Member States. Neither Option 1a, for which measurements of the electricity consumption of RFNBO production would be needed, nor Option 1b, for which monitors energy consumption and the quantity of RFNBOs produced is needed, would pose major difficulties.
- **Applicability in non-EEA countries:** This option can be implemented globally, but difficulties may arise in some regions. There are several sources that report renewable energy quantities for countries outside the EEA. Some of this data deviates significantly from other sources (e.g. World Bank and Eurostat). However, national sources should be available in most countries, but these are not necessarily comparable with each other. Measuring electricity consumption or RFNBO output of the plants in contrast should not be a major problem.

  The main question for target additionality in countries outside the EU is how this information should be monitored. The EU could require third countries not to count the electricity used for RFNBO production towards their renewable target. However, this requirement could provide the incentive for third countries to lower their RES targets. In addition to national targets, the National Determined Contributions (NDC) under the Paris Agreement could also provide an option in that the GHG targets reported there could be left unaffected by RFNBO production. As the NDCs usually do not specify RES targets, it is therefore not possible to establish a similar process on the basis of the NDCs as for the EU Member States. Furthermore, such an option would likely require adjusting UNFCCC accounting rules, which is beyond the scope of what can be recommended in this project. However, the question of how the EU can ensure that the countries from which RFNBOs are imported will follow the established procedure remains.
- **Economic burden for operators:** The options (1a and 1b) would probably lead to only limited additional costs for economic operators. The operator is only obliged to prove the amount of electricity consumed and the amount of RFNBOs produced. This obligation can be carried out via electricity meters or by a quantity monitoring system. However, operators would be subject to a reporting obligation based on certain standards, which would incur limited costs.
- **Administrative burden:** Compliance under these options (1a and 1b) can be verified using centrally available data and documents that need to be submitted by the economic operators. Auditing can be largely automated, and public authorities can use existing templates or processes. The collection of the necessary data of this option does not involve high costs. The uncertainty of Member States as to whether the RES-E targets will be met is mitigated by deployment additionality and can be ensured by continuously monitoring if RES deployment has to be supported by the Member State. However, the need to revise the current regulation in the RED II with respect to the treatment of RFNBOs is a general drawback.

Option 2 (Ex ante):

- **Effectiveness for target level additionality:** This option is less precise than Option 1 in terms of measuring target additionality. For example, if more electricity for RFNBO production is demanded than expected, there would be no target additionality for the unexpected part of RFNBO electricity demand. However, continuous updates of the forecasts can prevent them from being too far from real developments. In particular, the Governance Regulation foresees an update of the NECPs in 2023 or 2024 and progress reports every two-years afterwards, which could be used as a basis for adjusting projections.

- **Applicability across Member States:** The option can technically be implemented without major issues across the EU. The required data sources and documents are available from Member States. For the baseline and the forecasts, the NECPs or EUCO scenarios are available.
- **Applicability in non-EEA countries:** The option can be implemented globally, but difficulties may arise in some regions as there are no standard documents, such as NECPs, that forecast renewable electricity production. In most countries, there are no forecasts for RFNBO production. In some cases, national projections or NDCs could be a potential source for RFNBO production forecast. A study of these sources regarding RFNBO production and renewable targets until 2030 would have to be carried out for this purpose. However, the same problems arise in this option as in Option 1 regarding national targets or NDCs, which makes it very difficult to apply the option outside the EEA.
- **Economic burden for operators:** The option would probably lead to no additional costs for economic operators because, unlike Option 1, it does not measure the amount of electricity used for RFNBO production. Instead, it measures the expected amount of electricity, so the operators have no reporting obligations and no costs. However, updates of the forecasts would require the same data to be collected as in Option 1.
- **Administrative burden:** The expected amount of renewable electricity can be taken out of the NECPs without any problems. However, the expected amount of electricity for RFNBO production may be somewhat more difficult to identify in the NECPs but may be feasible for the Member State itself, as it should have the underlying data available. In order to keep forecast deviations from existing data to a minimum, updates of the forecasts can be made, which incur costs in turn. The need to change Member States RES targets accordingly is a drawback for this option.

The two ex post options (1a and 1b) and the ex ante option described at the beginning of Section 10.3.2.3 are ways to foster target additionality in Member States. These options should prevent additional RES-E capacities for RFNBO production from being counted against the RES target, complementing deployment additionality on a systems level. In other words, other economic sectors should have the same amount of RES-E available as without RFNBO production. Both options have their advantages: The ex post options are better suited to ensure target additionality with full additionality given by Option 1a, whereas the ex ante option identifies a pathway of deployment that can be particularly valuable for Member States' planning. Target additionality's applicability to non-EEA countries exporting RFNBOs to the EU is the main problem of all the options analysed previously. Although the EU may impose requirements on the RES targets or on the creditability of RES-E use of RFNBO generation, the EU may have little leeway to implement these approaches in these countries.

Recommendation

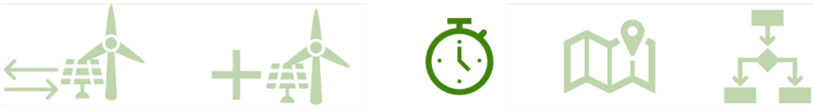
To foster additionality on the level of RES targets, several options are conceivable and should be analysed regarding the ease of implementation within current policy processes:

- Ex post by not including RES-E for the production of RFNBOs in RES target achievement at all, which would require changes in RED II

- Ex post by only including the energy content of the RFNBOs in RES target achievement, which would also require changes in RED II
- Ex ante by increasing the RES targets by the expected RES-E consumption of RFNBO production, which would require a target update in RED II and national contributions to the EU RES target

Given the large uncertainties about the reliability of an ex ante assessment, further analysis will focus on the first two options.

10.3.3 Temporal correlation



Establishing options to fulfil the requirement of temporal correlation largely consists of determining this correlation in two dimensions:

- **System boundary of electricity production**: How narrowly must the electricity production be defined with which temporal correlation is to be demonstrated? Here, the project team sees three possibilities:
  - The RFNBO producer correlates with one or a group of RES-E units that it has a permanent economic relationship with.
  - Correlation with any RES-E unit: The RFNBO producer may not have a permanent economic relationship with this unit and may correlate with different units at different times.
  - Correlation with total RES-E infeed at system level: System may, for example, mean a bidding zone, a country, or a region before a grid bottleneck (see Section 6.4.4)
- **Degree of correlation**: To what quantitative extent must there be temporal correlation and at which granularity (e.g. is evidence required on hourly, daily, or monthly resolution)? Here, the project team simplifies to two possibilities:
  - Full correlation: The entire load of the RFNBO production must be correlated with RES-E production at an intraday granularity.
  - Partial correlation: Only parts of the RFNBO production load must be correlated or temporal granularity daily or less often (e.g. monthly).

The possibilities in these two dimensions can be combined as shown in Table 22 to arrive at six options to fulfil the requirement of temporal correlation. Each of the options is assessed in the following, and an overview of the assessment can be found in Table 23.

Table 23. Definition of options for temporal correlation

	Full correlation	Partial correlation
Correlation with one or a group of RES-E units	Option 1: Full correlation with contracted RES-E unit(s)	Option 2: Partial correlation with contracted RES-E unit(s)

Correlation with any RES-E unit	Option 3: Full correlation with any RES-E unit(s)	Option 4: Partial correlation with any RES-E unit(s)
Correlation with RES-E infeed at system level	Option 5: Full temp. correlation with RES-E generation at system level	Option 6: Partial temp. correlation with RES-E generation at system level

Source: Guidehouse

Table 24: Preliminary evaluation of options to fulfil the requirement of temporal correlation

Options to fulfil requirement	Effectiveness for RED II compliance	Applicability across MS	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
Full correlation with contracted RES-E unit(s)					
Partial correlation with contracted RES-E unit(s)					
Full correlation with any RES-E unit(s)					
Partial correlation with any RES-E unit(s)					
Full temp. correlation with RES-E generation at system level					
Partial temp. correlation with RES-E generation at system level					

Full correlation between RFNBO production and contracted RES-E unit(s) would be an option that is very close to the RED II example that that RFNBOs “cannot be counted as fully renewable if they are produced when the contracted renewable generation unit is not generating electricity.” It would mean that for example for every hour, the electricity consumption of the RFNBO plant must be matched by an equal amount of RES-E infeed from the corresponding unit or units (Ørsted, 2020; Global Alliance Powerfuels, 2020; Power to X Alliance, 2020). It would require metering with sufficient temporal resolution both at the RFNBO and the RES-E plant. This requirement would cause some administrative burden to setup, report, and audit, but it could technically be performed globally without major effects from national circumstances. Another vehicle could be a PPA where the RFNBO producer pays the RES-E producer for real-time RES-E supply (Cerulogy, 2019).

In the evaluation of the different options, it is important to take into account the basic techno-economic considerations for RFNBO production. The cost of hydrogen production via electrolysis, which is of primary concern here, is largely determined by the cost of electricity, efficiency of conversion, CAPEX of the whole installation, and FLHs. There are inherent trade-offs between these elements; for instance, higher FLHs are desirable as they lower the relative weight of CAPEX (from a levelised cost perspective) but might come at increased electricity prices. If full correlation with specific contracted RES-E units is required, the RFNBO producer would have to design all plant operation and value chain steps after this to be adaptable to the infeed of these specific RES-E assets. This could be eased by defining RES-E production in this context by the day-ahead forecast instead of existing infeed, which would ease the planning of RFNBO production operations (Ørsted, 2020). It would, however, still leave the fundamental issue of RES-E infeed intermittency. RFNBO producers would have several options to deal with this, each leading to negative economic effects for their operations:

- Accepting lower load factor of RFNBO production due to RES-E intermittency: This option would increase RFNBO costs because upfront investment, which is still high for most RFNBO technologies, would need to be amortised over fewer operating hours (Global Alliance Powerfuels, 2020).
- Installing hydrogen storage to supply subsequent process steps continuously with hydrogen: This option would require costly storage tanks and not solve the problem of a low load factor, at least for the electrolyser. This result can be partly mitigated by siting RFNBO production on sites with existing SMR hydrogen production, which offers load flexibility. However, that option opens up further discussion on how to deal with electrolytical or fossil-based hydrogen blends produced on the same site.
- Oversizing the RES-E asset (e.g. matching each MW RFNBO production with 2 MW RES-E capacity): This option would mitigate the problem by increasing RFNBO load factors in times of partial RES-E infeed. It would, however, require much larger upfront investment and might lead to excess RES-E with little revenue potential (Global Alliance Powerfuels, 2020).
- Installing a battery behind-the-meter to flatten intermittent RES-E infeed: This option would be associated with significant additional investment. Also, it would have to be planned in the DA.
- Electrolysers have to keep a minimum load (between 1%-20%, depending on technology): These values are established due to gas purities and subsequent safety standards. RFNBO production will therefore have to maintain 24/7 production at some minimum level to avoid possible complications. Such a situation will require flexibility for RES-E procurement or (as outlined previously) electricity storage solutions onsite, adding costs.
- Connected to the two points above, each electrolyser also has an ideal working temperature and fast load changes affect its efficiency and contribute to material degradation. With lower loads, less heat is produced, and ideal temperature might not be reached, whereas with overloading, additional cooling is needed (Wulf, Linssen, & Zapp, 2018). Again, flexibility in RES-E procurement is needed to make sure that these assets are used in a scalable way.
- Finally, RFNBO producers could, in order to alleviate some of the issues above (e.g. oversizing, minimum load, and ideal working temperature), procure simple grid electricity mix to maintain their operations. Such synthetic fuels produced would not meet RED II requirements. However, producers could still use these as drop-in fuels and gain economic value. A major issue here are the economics of synthetic fuels. The costs of synthetic petrol produced (even in premium conditions in Europe) is 5 times higher than the costs of conventional petrol, and still expected to be 3-4 times higher in 2030 (Agora Energiewende, 2018). Under such conditions, RFNBO producers would lose major economic value by producing non-renewable synthetic fuels.

To alleviate these adverse economic effects, requiring only a **partial correlation between RFNBO production and contracted RES-E units** is an option (FuelsEurope, 2019). For instance, instead of matching RFNBO energy consumption and RES-E infeed at an hourly basis, this rate could be softened to daily (Global Alliance Powerfuels, 2020) or even monthly (Shell, 2020) granularity. This would give RFNBO producers more flexibility and reduce the economic burden.

On the other hand, this option would not ensure compliance with the RED II requirement that RFNBO production should only take place during RES-E production. This is because RES-E infeed varies significantly within single days. Solar PV has close to zero infeed by night by its very nature, and wind strengths are often also highly variable. If electricity volumes are matched daily or less often, there is no certainty for temporal correlation.

To make RFNBO producers less dependent on single RES-E units and alleviate economic burden, fulfilment of this requirement could be extended to **full correlation of RFNBO production with any RES-E units**. This would mean that RFNBO producers would have to use RES-E GOs that contain the hour of RES-E production and match their hourly electricity consumption with an equivalent amount of GOs. As a consequence, RFNBO production would have strong temporal correlation with RES-E production—however, not specifically with a RES-E production unit that is connected to RFNBO production through a PPA, as planned in Recital 90.

A major issue with this option is that GOs with such a temporal granularity do not exist in the EU. While these may be developed in the European market soon, in many markets outside Europe this development seems unlikely. This option, therefore, faces significant obstacles regarding administrative roll-out and applicability outside the EEA.

To avoid this problem, one might only require **partial correlation of RFNBO production with any RES-E units**. This option would work like the previous, but match energy volumes only on a daily or monthly basis. Therefore, existing GO schemes could be used in the EU, which would allow for a minimal administrative burden (Shell, 2020). Outside the EEA, there are, in contrast, many markets where such GOs do not exist.

The compliance with RED II is, however, highly questionable under this option if the temporal matching is set too lax (e.g. monthly). As with the previous option, this option does not determine temporal correlation regarding a RES-E production unit that is connected to RFNBO production through a PPA, as planned in Recital 90. On top of this, there would not even be ensured temporal correlation with these non-PPA RES-E assets because RES-E might have been produced at a different time in the month than RFNBO production occurred. At the lowest granularity possible with current GOs—daily matching—some temporal correlation is provided, but there may still be, for instance, electricity consumption matching at night with RES-E production during the day.

Full temporal correlation of RFNBO production with RES-E generation at system level is another conceivable option. RFNBO production would be temporally correlated in hours with (almost) fully renewable electricity supply in the respective system (see Section 6.3.4 for a discussion on the definition of system). The motivation behind the shift of temporal correlation from RES-E unit to system level is that in electricity systems with still significant non-renewable generation, the system perspective could be more meaningful when determining whether an RFNBO plant consumes RES-E. For example, if an RFNBO unit produces simultaneously with the RES-E unit it has a PPA with but at a time of relatively low RES-E share in the overall electricity mix, the additional electricity demand generated by RFNBO production could lead to activating a fossil fuel-based marginal power plant from a system perspective. Also, considering the system perspective would ensure a higher contribution of RFNBO production towards RES-E system integration.

This shift to system perspective deviates from the wording of Recital 90, but it would be in line with its objective (RFNBOs should not operate at times of no or low RES production). The most important downside of full temporal correlation at system level would be that, in most countries within and outside the EU, the number of hours with (almost) 100% RES-E share in the system is limited. RFNBO operators would, therefore, achieve only low load factors for their production assets, resulting in a high economic burden.

To reflect this result, a more applicable option could be to require **partial temporal correlation of RFNBO production with RES-E generation at system level**. RFNBO production would be temporally correlated in hours where the RES-E share in the system exceeds a certain threshold (e.g. the average RES-E share in the system 2 years prior—the same percentage used for calculations in Section 2.2.1). This option would give RFNBO producers a higher number of operating hours per year than would be the case with full correlation. To increase planning security for operators, compliance could be based on day-ahead forecasts. Administrative burden would be comparatively small since national, publicly available data could be used. In some non-EEA countries, however, RES-E shares may not be as easy to determine (see Section 4.2.3).

A disadvantage would be that RFNBO producesr would still be operating at times when the marginal power plant in the system is not renewable, formally activating that marginal power plant and leading to incremental emissions. Such adverse effects would need to be addressed by additionality requirements. These additional RES-E plants would create capacities which would push some of the fossil marginal plants out of the merit order, offsetting the aforementioned activation of a marginal fossil plant. A strong additionality requirement could, therefore, enable a more flexible design of temporal correlation.

Recommendation

In the medium term, full correlation of RFNBO production with any RES-E unit or units could provide some RES-E system integration benefits while being somewhat close to Recital 90 wording. Respective proofs would, however, need to be developed (e.g. GOs could be upgraded to include more granular information on the time interval of the RES-E production). In the short term, three options could be implemented with existing vehicles, although they are associated with some shortcomings:

- Partial temporal correlation of RFNBO production with RES-E generation at the system level would differentiate Case 3 from Case 2 and use upcoming RFNBO capacities for RES-E system integration. However, it would deviate from the wording of Recital 90.
- Full correlation with contracted RES-E units would be closest to the RED II wording but would provide limited system integration benefits.
- Partial correlation of RFNBO production with any RES-E units could be carried out through GOs and would provide temporal correlation by date, albeit leaving loopholes, such as matching consumption at night with daytime RES-E production.

10.3.4 Geographical correlation

Table 24 shows a long list of conceivable options by which RFNBO producers could demonstrate compliance with this requirement. Some of them are not in line with the objectives of RED II, but are discussed here as they have been brought forward by industry stakeholders. Each option is assessed using the rating system explained in Section 10.1 and explained in more detail in the following.

For any of these options, RFNBO producers should be able to know at the time of plant construction whether this plant will fulfil the requirement over its entire lifetime. Otherwise, the risk of the plant being in a wrong location due to changing circumstances and becoming a stranded asset may severely impede the scale-up of RFNBO production (Ørsted, 2020; Global Alliance Powerfuels, 2020). This long-term perspective on geographic correlation is also in line with the definition of structural congestion in Commission Regulation (EU) 2015/1222: a "congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions," assuming that "stable over time" refers to timeframes of at least around 10 years.

An issue with this ex ante approach is that in cases of new, unforeseen grid bottlenecks, some RFNBO plants may no longer be compliant with geographical correlation but would legally still fulfil the requirement due to the permanent assurance of compliance they received when installing the asset. This risk is, to some extent, mitigated by the extensive grid planning process in Europe (e.g. by ENTSO-E). Investment safety can, therefore, be prioritised over avoiding such cases that would undermine geographical correlation.

One option to fulfil this requirement would be that **RFNBO and RES-E assets must be in the same distribution network** (Power to X Alliance, 2020). There are well over 2,000 distribution system operators in Europe (JRC, 2016), meaning that each network is geographically rather small. Hence, this would be a strong interpretation of the RED II requirement of geographical correlation. Also, it would be fairly simple to demonstrate compliance as the location of both assets would be sufficient for an audit in most cases.

A disadvantage, however, is the economic effect of the aforementioned small area of distribution networks. The available RES-E offering in each distribution network will be relatively small, making it difficult to source RES-E at competitive prices. Alternatively, RFNBO producers could procure cheap RES-E and then locate their production accordingly, which, in turn, would limit their options to obtain an attractive production site.

Table 25. Preliminary evaluation of options to fulfil the requirement of geographical correlation

Options to fulfil requirement	Effectiveness for RED II compliance	Applicability across MS	Applicability in non-EEA countries	Economic burden for operators	Administrative burden
Same distribution network					

Same side of grid congestion within bidding zone					
Same bidding zone					
Same Country					
Different zones if coupling capacities allow					
Provision of ancillary services					
Location in region with high curtailment					
Maximum 50 km distance					
Maximum 500 km distance					

A broader approach would be to require **RFNBO and RES-E asset to be located in the same bidding zone** (see Section 6.4.4). This option would be fairly simple to audit with the location of both assets. In countries without wholesale electricity markets, a closer look at sector organisation may be required to define what the respective equivalent for bidding zones is. As bidding zones are geographically much larger than distribution networks, the economic burden for RFNBO producers is lower than in the previous option as they have a significantly larger market they can source RES-E from.

A potential issue with this option however is that it may not warrant the Recital 90 text that both assets "are located on the same side in respect of the congestion." Bidding zones usually represent liquid electricity markets by nature; Regulation (EU) 2019/943 defines them as the "largest geographical area within which market participants are able to exchange energy without capacity allocation," making it in principle a suitable option to fulfil this requirement (Ørsted, 2020; Global Alliance Powerfuels, 2020). There are, in practice, also cases where structural grid bottlenecks exist within bidding zones as outlined in ACER's 2018 market monitoring report (ACER, 2019).

Figure 23: Bidding zone configuration in Europe

Source: ENTSO-E, 2018

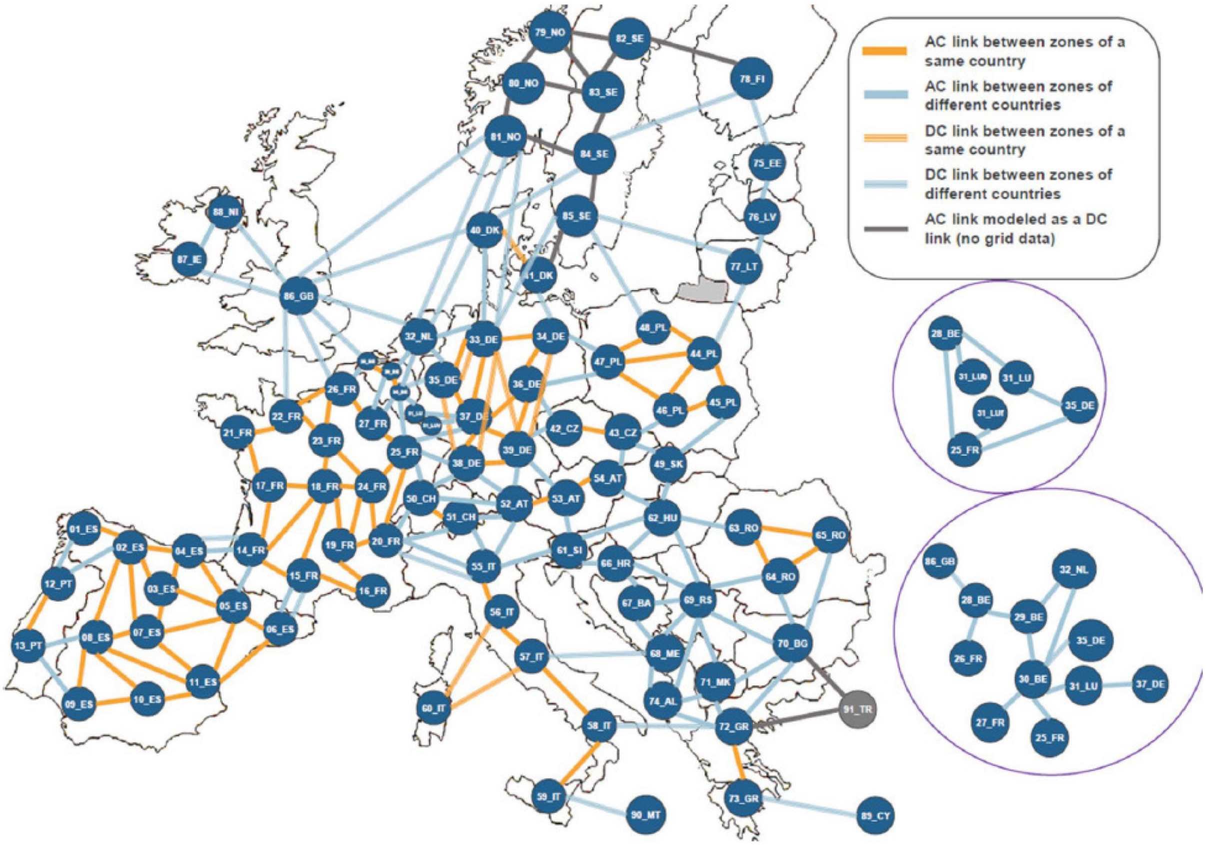
Considering **bidding zones, including grid congestions within them** would be a refined option. This approach would be very close to the wording of Recital 90. An issue however would be how to identify grid bottlenecks within bidding zones.

For Europe, the bidding zone configuration technical report (ENTSO-E, 2018) and the corresponding market monitoring report (ACER, 2019) would provide a thorough basis. For instance, one of the configurations defined by upcoming bidding zone review could be used to define also the geographical correlation in the RFNBO context. This approach would allow for a consideration of structural grid bottlenecks for RFNBO production sooner than in the option of solely relying on bidding zones. Bottlenecks would only be considered once bidding zones are split. Using existing ACER and ENTSO-E reporting to define intra-bidding zone bottlenecks would create limited administrative burden to implement and could be approached in a Union-wide process.

A very granular approach would be to refine bidding zones with the zonal model used by ENTSO-E (see **Error! Reference source not found.**). This would be very close to the intent of Recital 90. However, it would allow RFNBO producers to source RES-E from a rather small market.

An interesting alternative and a possible solution to some of the issues discussed previously would be to give Member States or TSOs possibility to create a **positive list for areas within their bidding zone for which they do not expect grid constraints when adding RFNBO production facilities.** RFNBO production located in these areas would be considered as respecting grid congestion within a bidding zone. For countries outside Europe, however, a country-specific approach would be needed. In some countries with no transparent TSO reporting, unambiguously identifying structural grid bottlenecks would likely require complex case-by-case evaluations.

Figure 24. European zonal model used by ENTSO-E



Source: ENTSO-E, 2020

In some cases, there may be sufficient transmission capacities between (bidding) zones to argue that **RFNBO and RES-E assets are in different zones with no grid bottleneck between them** (Power to X Alliance, 2020; Shell, 2020). This would, by definition, fulfil the RED II objective of no congestion between RFNBO and RES-E production. The electricity price spread projected by ENTSO-E could be an indicator to decide whether there is sufficient transmission capacity between two zones (ENTSO-E, 2020). If price spreads at one border are projected to stay small (e.g. less than 5 EUR/MWh) over the coming 10-20 years, the two zones might be considered as one zone to fulfill the requirement of geographical correlation for RFNBO production.

An alternative option would be to simply oblige **RFNBO and RES-E assets to be located in the same country**. This would create minimal administrative burden and would be extremely easy to audit globally. Depending on the size of the RES-E market in the respective country, this might create some economic burden on RFNBO producers, similar to the same bidding zone option.

However, requiring location in the same country would not ensure that RFNBO and RES-E production are not separated by a grid bottleneck. There are already EEA countries with several bidding zones on their territory due to such grid constraints (e.g. Italy, Sweden, and Norway). As an extreme example, RFNBO production in northern Italy could, under this option, claim to be correlated with a RES-E asset in Sicily, although there are obviously grid bottlenecks between the two, evidenced by the crossing of four bidding zone borders. While there is just one bidding zone in most Member States today, the aforementioned bidding zone review process makes a definition via bidding zones responsive to the detection of structural bottlenecks. Relying solely on country territory would fail to identify one. The aforementioned concept of positive lists for areas for which governments and TSOs do not expect grid constraints could also be applied here as a solution.

An option that could be seen as an elective alternative to the above options would be for **RFNBO producers to provide ancillary services to the grid** (Power to X Alliance, 2020). For instance, if an RFNBO asset offered a certain amount of frequency reserve or if it can be interrupted by the TSO when necessary, it could fulfil the geographic correlation requirement. The reasoning behind this approach is that not aggravating grid bottlenecks is one motivation for this requirement. Providing ancillary services may lead to a similar result without explicitly relying on locations. Economically, this could be an attractive option for operators as they would also receive compensation for these ancillary services. As a downside, the short-term nature of ancillary services markets makes it impossible to certify the fulfilment of this requirement ex ante for the lifetime of the RFNBO plant. Also, in many countries (even within the EEA), ancillary services markets may not be fully transparent, making auditing more burdensome.

Another elective option would be to see the requirement of geographical correlation fulfilled if the **RFNBO production is located in regions with high RES-E curtailment** (Power to X Alliance, 2020). This would implicitly address the RED II requirement, assuming that RES-E curtailment in such a region occurs due to grid constraints and not due to systemwide oversupply. An issue with this would be that a clear and binding methodology would be required to identify such regions.

Lastly, geographical correlation could be proven simply by setting a **maximum distance (in kilometres) between RFNBO and RES-E assets** (Power to X Alliance, 2020). As an advantage, this approach would be extremely easy to audit globally. RED II compliance would be unclear, however. If the distance threshold was set to 500 km, for example, there may be a grid bottleneck between the two assets (e.g. when crossing country borders). If the distance was set small (e.g. 50 km) this bottleneck would be less likely, but it would place a significant economic burden on operators because they would need to source their RES-E from a small market.

Proposals that the regional consumption of RFNBOs should count towards geographic correlation (Power to X Alliance, 2020) were not considered here as the RED II requirements address the generation, not the consumption of RFNBOs.

Recommendation

Geographical correlation could be determined through bidding zones and be refined through the upcoming ACER configurations or ENTSO-E zones. To reflect increasing interconnection capacities, neighbouring zones with high power price convergence might be considered as one zone. To avoid creating grid congestion in the future, Member States or TSOs could be asked or allowed to define positive lists for areas within their bidding zone where they do not expect grid constraints in case of adding RFNBO production. Outside of Europe, geographical correlation may require case-by-case analysis and ultimately rely only on national borders as a definition.

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