

Impact of RFNBO delegated act regulatory variants

Perspective from a multi-energy European model

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Authors

CLIMACT

Noémie Bidoul
Dimitri Krings
Corentin Bonte

Systemik (UCLouvain)

Antoine Laterre
Mahdi Kchaou
Francesco Contino

ULiège

Umair Tareen
Sylvain Quoilin

Executive Summary

Regulatory context

Commission Delegated Regulation (EU) 2023/1184, adopted in June 2023, defines the **additionality, temporal and geographic correlation criteria** that electricity must satisfy for hydrogen and its derivatives to qualify as renewable fuels of non-biological origin (RFNBOs). Three years on, renewable hydrogen production has barely started: electrolytic production in the EU remained below 50 ktons in 2024 [1], orders of magnitude away from the 10 Mtons of aspirational domestic production targeted by REPowerEU for 2030. Some stakeholders argue that the criteria are a significant part of the explanation and are calling for the relaxation of them ahead of the review of the act, initially planned in mid-2028.

Purpose and goal of this study

The purpose of this study, commissioned by the Environmental Defense Fund Europe, is to **assess the impacts that relaxing the regulation requirements** would have on the European energy system. **Eight different policy variants** are investigated in order to study the individual and combined impact of relaxing different requirements of the regulation. The variants cover: delayed additionality requirement, delayed and removed hourly matching requirement, relaxed carbon intensity and renewable share exemption thresholds, a combined delay of additionality and temporal correlation requirements together with the relaxation of exemption threshold¹, a relaxed geographic correlation allowing sourcing from interconnected zones, and — in the other direction — the removal of the exemptions altogether. **The impact is assessed along five indicators:** investments in renewable electricity production capacity, CO2 emissions, electricity prices, renewable hydrogen production volume, and renewable hydrogen cost.

Methodology

The assessment relies on **PyPSA-RFNBO, a sector-coupled cost-optimisation model of the European energy system** developed specifically for this study, based on the open-source PyPSA-EUR model [2]. The PyPSA-RFNBO model covers the EU27 plus Great Britain, Norway and Switzerland and excluding Cyprus and Malta, run at hourly resolution over five-year investment steps from 2025 to 2050 with myopic foresight, and extended with a constraint module reproducing the requirements of the delegated act. All scenarios are constrained to follow the EU net-zero trajectory. Under a less ambitious decarbonisation pathway, renewable penetration would be more fossil-dependent; the emission increase associated with the policy relaxation would plausibly be larger, though this has not been tested. Results should thus be read as directions, rankings and orders of magnitude rather than as exact numerical estimates; **Section 2** sets out explicitly what they can and cannot be used for.

Key findings

Several main conclusions arise from the study.

¹ Similarly to the proposition made by four Directors-General of Austria, Germany, The Netherlands and Spain, along with one State Secretary of Poland, in a Joint Letter to the European Commission.

First, **the regulation requirements are not the factor that prevents renewable hydrogen production from scaling**. In every variant, including the most permissive ones, domestic production only takes off in the 2030-2035 period, because renewable hydrogen remains structurally more expensive than imports and steam methane reforming, until CO₂ prices rise sufficiently.

Second, **delaying additionality or hourly matching does improve the economic viability** of the projects that do materialise in 2035 — the EU weighted-average LCOH falls by 0.1 to 0.25 €/kg and production increases by 0.4 to 0.5 Mtons, compared with the Current Regulation scenario. However, **these improvements are made at the cost of detrimental systemic impact on the energy transition: increased electricity prices** (up to 1.8% higher in 2035, EU average), 1.7 to 3.2 bn€ **less renewable investment over the 2025-2050 period**, and about 20 to 68 MtCO₂e **more emissions**² over the same timeframe. As mentioned previously, the total increase in emissions could possibly be larger if countries do not follow net-zero trajectories, although this has not been tested. Additionality and temporal correlation also work as a pair: once additionality no longer applies, the whole renewable fleet becomes eligible and the hourly matching requirement becomes more permissive. Delaying both additionality and hourly matching while relaxing exemption threshold, as proposed by five Member States in their joint letter, has the worst systemic profile of all variants tested (-9 bn€ of renewable investment and about +90 MtCO₂e² over the 2025-2050 period, +1.7% on electricity prices in 2035), with persisting effects in the long term.

Finally, **the exemption thresholds, by contrast, appear well calibrated**. Relaxing them — from 18 to 36 gCO₂eq/MJ, or from 90% to 80% renewable share — has minimal impact, because in a net-zero trajectory most grids have already crossed them by the time hydrogen production becomes significant. Removing them altogether is not desirable either: it forces PV-dominated grids, whose solar profiles cannot economically meet hourly matching, into a costly renewable build-out, cuts their hydrogen production and increases emissions from 2040 onwards. This conclusion holds as long as countries keep developing renewables along a net-zero pathway; under a slower decarbonisation, the thresholds would bind for longer and their protective role would be more important.

On this basis, the study recommends **preserving the three pillars and the current exemption thresholds**, while focusing action on other levers that could support renewable hydrogen production: a strong ETS to ensure its competitiveness versus fossil alternatives; along with policies that accelerate renewable deployment, lowering electricity costs and preventing renewable cannibalization.

Report outline

The report is structured as follows. **Section 1** details the methodology, including the description of the PyPSA-RFNBO model (**Section 1.1**), the assumptions of the baseline scenario (**Section 1.2**), and the implementation of the regulation requirements (**Section 1.3**). **Section 2** provides the study results, including a description of the Current Regulation scenario (**Section 2.1**, used as reference to compare the different policy variants), detailed impact assessment of each policy variant (**Section 2.2**), and a cross-cutting comparison between variants (**Section 2.3**). Finally, policy recommendations and conclusions are provided in **Section 3**.

² Approximated through integration, as the model only generates estimates for a given year every 5 years.

Acronyms

CAPEX	Capital Expenditures
CO2	Carbon Dioxide
ETS	Emission Trading System
EU	European Union
GHG	Greenhouse Gases
H2	Hydrogen
LCOH	Levelized Cost of Hydrogen
MS	Member State
OPEX	Operational Expenditures
PPA	Power Purchase Agreement
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
TSO	Transmission System Operator

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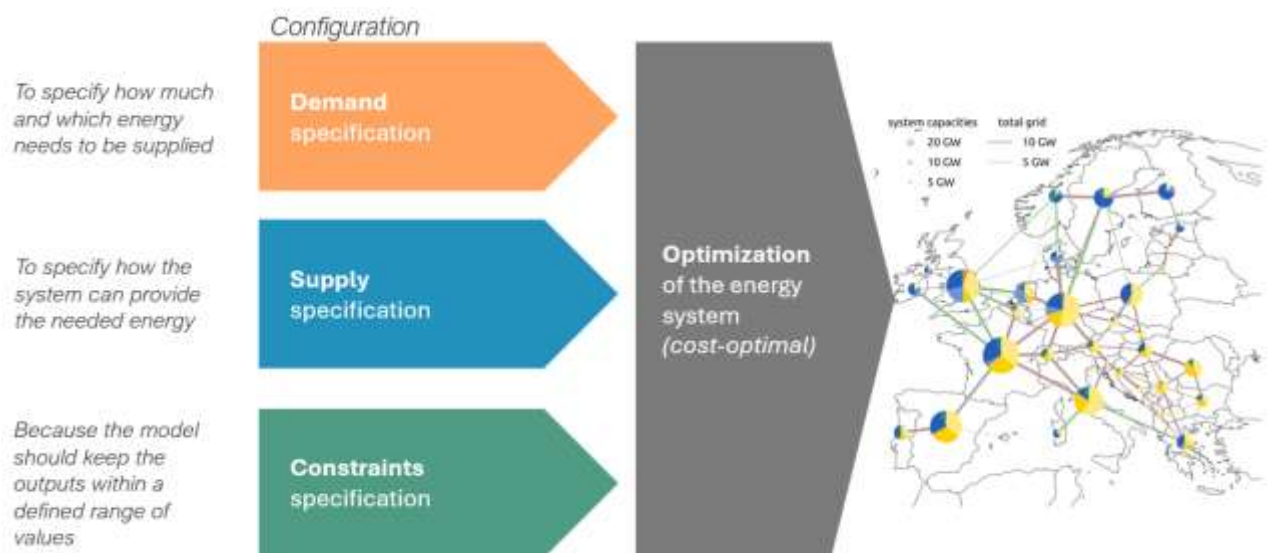
1. Methodology & model

To assess the impact of relaxing different dimensions of the RFNBO Delegated Regulation on the energy system, a techno-economic optimization model representing the European energy system (described in [Section 1.1](#)) was used. The model workflow relies on a baseline scenario (without RFNBO Delegated Regulation constraints), which includes a certain number of hypotheses on the energy demand, supply and CO₂ constraints (described in [Section 1.2](#)). The requirements of the current regulation, along with several regulatory variants, were implemented into the model and ran into corresponding scenarios (the constraints implementation are described in [Section 1.3](#)).

1.1. About the PyPSA-RFNBO model

The open-source **PyPSA-RFNBO** model developed for this project is an adaptation of the open-source **PyPSA-Eur** framework [2] (version v2026.02.0), extended with a constraint module implementing the RFNBO criteria of Delegated Regulation (EU) 2023/1184 (https://github.com/IntSusEnergySystems/pypsa-eur_RFNBO). It is a **linear optimisation model** of the European energy system that minimises total annualised system cost (annualised investment plus operating costs), co-optimising capacity investment decisions and the hourly dispatch of all generation, conversion, storage and transport assets simultaneously.

Figure 1 – Illustration of the PyPSA-Eur model



1.1.1. Modelled countries

The geographical scope covers **28 countries**: the EU-27 excluding Cyprus and Malta, complemented by Switzerland (CH), Norway (NO) and the United Kingdom (GB).

The high-voltage electricity network (220–750 kV, based on OpenStreetMap data) is aggregated into **33 nodes** using k-means clustering, with at least one node per country and a finer breakdown of the largest countries. Cross-border exchanges are represented explicitly through existing AC lines and DC links, complemented by confirmed and under-construction transmission projects (TYNDP 2020, NEP). Transmission expansion is capped relative to today's volume (a factor of 1.0 in 2025–2030, rising progressively to 1.3 from 2040 onwards).

1.1.2. Modelled energy vectors

The model is fully **sector-coupled** and optimizes the following vectors: electricity, hydrogen, methane, liquid fuels and derived molecules (oil products, Fischer-Tropsch synthesis, methanol, ammonia, biomass-to-liquid), heat, biomass (solid and biogas) and CO₂.

On the demand side, the model covers electricity, residential and services heat, industry, road transport (with smart charging and vehicle-to-grid), aviation, shipping and agriculture.

1.1.3. Temporal granularity

The model is solved using a **2-hour resolution**³. A full year is simulated continuously — without recourse to representative weeks or typical days — which allows inter-seasonal flexibility to be properly represented (hydrogen cavern storage, thermal storage, hydro reservoirs), as well as extended periods of low renewable output.

1.1.4. Weather year

The reference climatic year is **2013**, a year commonly used as representative in PyPSA-based studies. Hourly profiles of renewable generation (wind, solar PV, solar thermal, hydro) and of temperature — the latter driving both heat demand and heat pump COPs — are generated with Atlite from the **ERA5** reanalysis and **SARAH-3** satellite irradiation data, on a 0.3° grid covering the domain 12°W–42°E / 33°N–72°N. Electricity demand profiles are drawn from the same climatic year, ensuring consistency between variable generation and consumption.

1.1.5. Investment years

Six investment horizons are modelled at five-year intervals: **2025, 2030, 2035, 2040, 2045 and 2050**. The starting point is an existing ("brownfield") fleet reconstructed from historical installed capacities, broken

³ An hourly resolution was also tested but proved to be computationally too demanding. Tests were carried out on a scaled-down model comprising 10 countries and confirmed that a 2-hour resolution was sufficient to capture the effect of the constraints.

down by commissioning year; assets are decommissioned across horizons according to their technical lifetime.

1.1.6. Myopic foresight

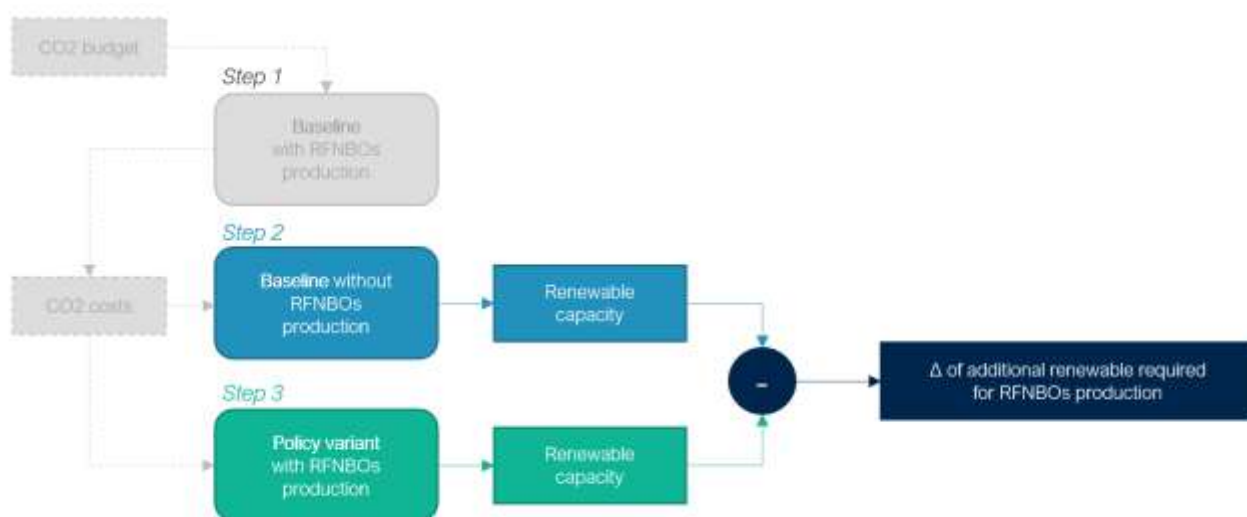
The model is solved under **myopic foresight**: the six horizons are optimised sequentially rather than simultaneously. At each horizon, the optimisation "sees" only the costs, demands, potentials and constraints (carbon budget, regulatory criteria) applicable to that particular year, without anticipating those of later periods. Capacities retained at one horizon are then passed on to the next as existing stock, net of decommissioning.

This approach differs from perfect foresight, where the entire 2025–2050 trajectory would be optimised as a single problem. It reflects more faithfully the actual behaviour of investors, who decide on the basis of prevailing conditions and signals, and it allows potential technology lock-in effects and stranded assets to emerge.

1.1.7. Model workflow

The impact of the RFNBO criteria cannot be assessed with a single model run. Additionality, in particular, is defined by reference to a counterfactual that does not exist inside a cost-optimisation model: it requires to estimate what renewable capacity *would have been built anyway*, a question a single optimisation has no way of answering, since every MW it builds is endogenous. The analysis is therefore built as a **sequence of three runs**, each one supplying the parameters that the next one needs. All three share the same model configuration and differ only in the switches described below.

Figure 2 – Workflow of the PyPSA-RFNBO model for the additionality criterion.



This run produces the two quantities that parameterise everything downstream:

- the **total molecule production volumes** per carrier (H_2 , CH_4 , CH_3OH , NH_3 , Fischer-Tropsch liquids)
- the **marginal price of CO_2** , i.e. the shadow price of the national carbon budget constraints, which becomes the carbon signal used in Steps 2 and 3 (see [Section 1.2.3](#)) for detailed explanation on CO_2 constraints implementation)

Step 2 - Baseline without RFNBOs

The second run aims at modelling a system in which the role of RFNBOs has been subtracted. It therefore **disables molecule production and removes the exogenous demand** from the system: electrolyzers, the hydrogen network, hydrogen turbines and fuel cells, methanation and hydrogen imports, etc., are all switched off. The system is re-optimised to serve the remaining energy demand, without RFNBOs. In this run, the CO_2 budget is removed. Instead, we use the marginal price from Step 1 as a proxy for a carbon tax, thereby increasing the overall system costs that the solver minimises. Since part of the energy demand was removed in this step, applying the same carbon budget would effectively relax the optimisation problem, allowing the remaining part of the system to emit more. Using the carbon tax proxy instead preserves the stringency of the optimisation and prevents the remaining part of the system from increasing its emissions.

Because the electrolyser load disappears from the system, so does the renewable capacity that had been built to serve it (maintaining unused assets would otherwise be costly and ineffective). The resulting variable renewable⁴ fleet is the **counterfactual VRE (Variable Renewable Energy) capacity**: the capacity Europe would have deployed in the absence of any RFNBO production. This is the reference point against which additionality is defined in Step 3.

Step 3 - Regulation with RFNBOs

The third run **restores the full molecule production and demand** system and applies the **complete set of RFNBO criteria** from Delegated Regulation (EU) 2023/1184 (additionality, temporal correlation and geographical correlation). Additionality is enforced based on the delta of VRE capacity, deduced from comparing capacity in Step 2 (baseline without RFNBO): only the extra VRE is eligible for RFNBO production.

Crucially, the absolute carbon budget is replaced by the **carbon shadow price taken from Step 1, as a proxy for a carbon tax**. This alternative approach is necessary to quantify the impact of current regulations and variants on emissions. Otherwise, the use of the carbon budget would result in identical emissions (i.e. the maximum permissible level).

1.2. Baseline scenario

This section describes the main hypotheses (demand, supply and key constraints) of the baseline scenario, in which no constraints are applied to the production of RFNBOs.

1.2.1. Demand hypotheses

⁴ We are referring here specifically to ‘variable’ renewable technologies (e.g. wind, solar), as ‘controllable’ capacities (e.g. hydroelectric dams, geothermal energy) remain the same across all scenarios (all available potential is utilised).

National energy demands are built from **statistical energy balances for the reference year 2023** rather than from a scenario projection. Annual final energy consumption per country, per sector (residential, services, industry, transport, agriculture) and per carrier is taken from **Eurostat energy balances**, complemented by Eurostat household balances for the residential end-use split and by national balances for Switzerland. **JRC-IDEES provides the finer disaggregation** used to split these totals **into end-uses**: space heating, water heating, cooking, appliances, transport modes, and industrial subsectors.

Demand for future horizons is not obtained by extrapolating 2023 consumption along a growth path. **Underlying activity levels are kept at their present levels**, and the evolution of demand is driven entirely by **exogenous assumptions** on technology and fuel switching applied to the 2023 base.

RFNBO demand

The demand for the different molecules eligible as RFNBOs is both set **exogenously** (externally imposed hypotheses) and **endogenously** (result of the model optimization), depending on the demand driver. Hydrogen can be supplied either through domestic steam methane reforming, domestic electrolysis, or imports, the specific share between these different sources being endogenous.

The demand assumptions can be endogenous or exogenous depending on the considered layer:

- **Layer 1 - activity levels:** *Exogenous throughout.* Steel, ammonia, methanol, chlorine and high-value-chemicals output, together with land transport, shipping and aviation activity, are taken from the 2023 statistical base (Eurostat energy balances and JRC-IDEES [3], complemented by sectoral statistics), see above section.
- **Layer 2 - technology and fuel shares:** *Mixed.* The split of an activity between competing drivetrains or process routes is imposed exogenously for land transport, shipping and steelmaking, and left to the model for aviation and for the naphtha feedstock of high-value chemicals.
- **Layer 3 - origin of the molecule:** *Endogenous almost everywhere.* Where a carrier can be supplied by more than one route - fossil oil against Fischer-Tropsch liquids, fossil gas against biomethane and synthetic methane, domestic electrolysis against imported hydrogen - the model chooses the mix on cost grounds, subject to the national CO₂ budgets.

The detailed demand assumptions are outlined in **Table 4** within the Appendix, which also specifies the amount of H₂ required to produce derived fuels. The sectoral trends are outlined below.

- **Land transport:** full electrification, no hydrogen. Road transport is electrified along a S-curve trajectory, from 5 % of activity in 2025 to 100 % in 2050, with the internal-combustion fleet declining symmetrically from 95 % to zero. Fuel-cell vehicles are set to zero at every horizon. The liquid fuel consumed by the residual combustion fleet may be fossil or synthetic; that split is endogenous.
- **Shipping:** hydrogen and e-methanol, with ammonia reassigned. Maritime transport follows a dual trajectory, with hydrogen rising from 1.5 % to 19 % of final energy and methanol from 2.6 % to 47 %, leaving 34 % of oil products in 2050. The shares are derived from the IEA Net Zero Roadmap 2023 [4], with one significant adjustment: the ammonia share foreseen by the IEA, which reaches roughly 44 % by 2050, has been reallocated to methanol because ammonia bunkering is not represented in PyPSA-Eur. This is a modelling constraint rather than a judgement on the fuel.
- **Aviation:** no exogenous mandate. No synthetic-kerosene or SAF share is imposed on aviation, as it is not allowed by the model architecture. Aviation demand is served from the oil bus, which the model may supply from fossil oil, Fischer-Tropsch synthesis or biomass-to-liquid. The renewable

share of aviation fuel is therefore entirely a model output, responding to the tightening carbon budget.

- **Steel:** hydrogen-based direct reduction. The primary, ore-based route declines from 74 % to 57 % of steel output as scrap-based production grows, while hydrogen-based direct reduction rises from zero in 2025 to 55 % of the primary route by 2045, where it plateaus. Together these two shares determine the industrial hydrogen demand from steelmaking. These numbers are sourced on an industry roadmap (Agora Industry) [5].
- **Chemicals:** ammonia and methanol routes imposed, HVC left open. Ammonia and methanol are the two cases where the production route itself is fixed. All ammonia is produced via Haber-Bosch and all methanol via methanolisation; the source of the hydrogen required for this production (electrolysis, SMR or imports) is defined endogenously by the model. High-value chemicals are treated differently: the recycling structure is exogenous, with virgin production falling from 85 % to 40 % as mechanical and chemical recycling grow, but the origin of the naphtha feedstock for the remaining virgin production is optimised between fossil oil and Fischer-Tropsch liquids.
- **Methane:** endogenous. No exogenous share of synthetic methane is imposed. Industrial and decentralised heating gas demand is served from the methane bus, which the model may supply from fossil gas, biomethane from upgraded biogas, or synthetic methane from methanation. E-methane demand is therefore a result rather than a hypothesis.

H2 imports

Extra-European hydrogen imports (assumed RFNBO-compliant) are available from 2030, subject to an annual ceiling rising from 197 TWh in 2030 to 253 TWh in 2050 [6] and an exogenous price declining from 75 to 54 €/MWh [7], both based on literature. The 2025 price is set at 1 000 €/MWh, which is prohibitive by construction and effectively excludes imports in the first horizon. These imports compete directly with domestic electrolysis and therefore act as a ceiling on the domestic RFNBO production that the criteria will later constrain.

1.2.2. H2 supply hypotheses

Cost and performance assumptions for hydrogen technologies are detailed in Table 5 within the Appendix. Under myopic foresight, the cost year follows the planning horizon, so each run draws the assumptions of its own five-year horizon.

Four features of the parameterisation deserve to be noted before the table is read.

- **Learning is concentrated on electrolysis.** Electrolyser CAPEX falls by 44 % between 2025 and 2050 and efficiency improves from 0.59 to 0.70, while SMR costs and efficiency are constant across the whole horizon. The competition between the two routes therefore shifts steadily in favour of electrolysis on technology grounds alone, before any carbon price or RFNBO constraint is applied.
- **The hydrogen turbine is not parameterised as a hydrogen technology.** PyPSA-Eur assigns open-cycle gas turbine costs and efficiencies to the H₂ turbine, an approximation flagged as a known limitation in the source code. Results on hydrogen re-electrification should be understood with that caveat.

- **Storage costs differ by more than an order of magnitude, and geography decides which applies.** Underground salt-cavern storage costs roughly one twentieth of steel tanks per kWh and has a hundred-year lifetime against thirty; on an annualised basis the gap is a factor of twenty-five. Only 12 of the 33 model nodes, covering 10 of the 28 countries, have eligible cavern potential. The remaining countries must store hydrogen in tanks, which effectively rules out seasonal storage for them and forces reliance on pipeline imports or on continuous production. Boil-off and leakage rates also differ between tanks and caverns; this is not represented in the model [8].
- **The fuel cell is penalised by its lifetime, not its CAPEX.** At 1 069 €/kW in 2050 the fuel cell costs roughly twice an open-cycle turbine, but its ten-year technical lifetime raises the annualised capital cost to 206 000 €/MW/yr against 57 000 for the turbine — a factor of 3.6. Comparisons of the two reconversion routes should be made on annualised rather than overnight costs.

A single uniform discount rate of 7 % applies to every hydrogen technology. The database differentiates only decentralised heating equipment and rooftop solar, at 4 %. The model therefore does not represent the specific financing conditions of electrolyzers.

On our assumption of excluded offshore caverns. The dataset records 22 107 TWh of offshore salt cavern potential against 8 828 TWh onshore and nearshore, so the configuration excludes roughly seven tenths of the mapped resource. Offshore caverns are excluded because their development costs and lead times are not characterised in the cost database used; including them at onshore cost levels would overstate the availability of low-cost storage.

1.2.3. CO₂ constraints

Decarbonization in the baseline run is driven by **absolute country-level CO₂ budgets**. The trajectory is uniform across countries:

Table 1 – CO₂ constraints applied in the baseline scenario at the different time horizons

Horizon	Budget (MtCO ₂ /year)	Equivalent reduction	Corresponding EU legal target
2030	2040	–55 %	European Climate Law interim target
2035	1247	–72.5 %	Upper bound of the EU nationally determined contributions
2040	680	–85 %	Amended Climate Law, excluding international credits
2045	227	–95 %	
2050	0	–100 %	Climate neutrality (stricter than EU law, as the latter accounts for domestic nature-based sequestration, i.e. LULUCF sinks).

The constraint applies to energy-related and industrial-process CO₂ within the modelled system boundary, referenced to 1990. It is complemented by a spatially resolved CO₂ system: capture on point sources and direct air capture with transport and sequestration (with constrained regional potential rising from 100 Mt/yr in 2030 to 250 Mt/yr in 2050 at a cost of 30 €/t). The zero budget in 2050 is therefore a **net** zero of the modelled scope: residual emissions may persist provided they are offset by capture and storage (CCS).

A further structural difference is that EU law sets a single Union-wide target, differentiated across member states through the Effort Sharing Regulation and a common EU-wide ETS cap, whereas the model imposes

an identical percentage reduction on every country, hence being more demanding than reality for certain countries (i.e. dense countries like Belgium).

Translation into a shadow price in the regulatory variants

The reason for not carrying the absolute budget into the regulatory runs is methodological rather than technical. Under a hard cap, the optimiser meets the imposed emission level at the smallest cost, regardless of the additional constraints applied in relation to the RFNBO delegated act. Every RFNBO variant would therefore return exactly the same emissions by construction, and the climate impact of the criteria — one of the central questions of the study — would be unobservable.

The workflow addresses this by extracting the **dual variable of the CO₂ constraint** from the baseline run. This shadow price is the implicit marginal cost of abating one additional tonne of CO₂ in the baseline system: the carbon signal at which the cost-optimal system happens to deliver the imposed budget.

In the subsequent runs, the cap is thus replaced by a per-country carbon price set to the baseline shadow price. Once the RFNBO constraints are layered on top, **emissions become a model output rather than an imposed input**. Each variant is free to emit more or less than the baseline depending on how the criteria reshape the system: stricter rules may reduce emissions where they trigger genuinely additional renewable capacity, or increase them where they divert renewable electricity away from grid decarbonisation or push electrolyzers towards operating patterns that require fossil back-up. Both directions are informative, and neither is visible under a cap.

Disclaimer: the shadow price is not an ETS price

The carbon shadow prices reported in this study are internal parameters of the modelling exercise. They should be used only to compare runs within the study, and **must not be read as a forecast of, or a benchmark against, EU Emissions Trading System prices**. Indeed, it differs in scope (covered sectors and greenhouse gases), geographical boundaries (national prices, where ETS is a single market), does not reflect speculative market behaviour, does not take free allocation into account, etc.

The correct interpretation is narrow: the shadow price is the carbon signal that reproduces the baseline decarbonisation pathway, held fixed across variants so that emissions can move. Its **level** carries no market meaning; only the **differences in outcomes** it enables between runs are interpretable.

1.3. Enforcement of current regulation requirements

This section describes the methodology through which the requirements from the RFNBO Delegated Act are enforced in the model through constraints.

1.3.1. Compliance pathways of the Delegated Act

Delegated Regulation (EU) 2023/1184 offers electrolyzers several routes to qualify their output as renewable. The model represents three of the five, selected on the basis of their relevance at system scale. Articles 3 and 4.3 were excluded on the grounds that both are project-level, contractual or operational arrangements whose eligibility depends on metering and TSO attestation rather than on system-level physical constraints. Article 4.3 in particular is a niche route that is difficult to establish in practice. Their omission means the model does not offer producers these escape routes, and **compliance costs are**

therefore an upper bound to that extent; where these routes are available in practice, actual costs could be directionally lower than reported here.

Table 2— Compliance pathways of Delegated Regulation (EU) 2023/1184 and their treatment in the model

Pathway	Requirement under the Delegated Act	Treatment in the model
Art. 3 — Direct connection	<i>Dedicated renewable installation via direct line or on site; if also grid-connected, metering must prove that no grid electricity is used. No additionality, temporal or geographic requirement.</i>	Not implemented (Direct-connected electrolyzers are disabled in the model)
Art. 4.1 — Grid above 90 % renewable	Bidding zone with a renewable share above 90 %; grid electricity counts as renewable. Production limited to a share of hours proportional to the RES share; five-year lock-in once the threshold is crossed.	Implemented as an exemption
Art. 4.2 — Grid below 18 gCO₂eq/MJ	Low-carbon bidding zone. Renewable PPAs, temporal and geographic correlation still required; additionality waived. Five-year lock-in once the threshold is crossed.	Implemented as an exemption
Art. 4.3 — Redispatch	<i>Electrolyser absorbs electricity that would otherwise be curtailed; requires TSO evidence of downward redispatch and a causal link.</i>	Not implemented
Art. 4.4 + 5/6/7 — Default pathway	Full compliance with additionality, temporal correlation and geographic correlation.	Implemented — the reference case for the study

1.3.2. Additionality (Art. 5)

What is implemented

The 36-month rule is translated into a pair of constraints operating from 2030 onwards, formulated against the counterfactual established by the “baseline without RFNBOs” run described in the previous section:

- **Capacity constraint** — new RFNBO (electrolysers and other RFNBO related technologies) capacity built over an investment period cannot exceed the additional renewable capacity that RFNBO production induces, measured as the difference in installed VRE capacity with the baseline without RFNBOs (i.e. only extra VRE is eligible).
- **Annual energy constraint** — annual electricity consumption of electrolysers and other RFNBO related technologies cannot exceed the annual generation of that additional renewable capacity. This is the “annual PPA equivalent” of the volume-matching requirement.

Together these reproduce the intent of Article 5: **electrolysers can only grow in step with the renewables they bring online**. The scope is national, in the sense that the additional capacity must be located in the same bidding zone as the electrolyser.

What is not implemented

Three elements of Article 5 fall outside the model:

- **The exclusion of subsidised installations**, and its exceptions (aid received before repowering, support for land or grid connections, fully repaid support, R&D and demonstration projects). Support schemes are not represented, so no renewable asset is disqualified on this basis.
- **PPA portability**, that is, the retention of qualified status when a contract ends and is replaced by another. Contracts are not modelled as objects.
- **The Article 11 transitional waiver**, which exempts installations operational before January 2028 from additionality until 2038. The model applies additionality from 2030 with no grandfathering, which makes the modelled regime materially stricter than the regulation over the 2030–2038 window. This is the single most consequential simplification on this criterion and should be borne in mind when reading the 2030 and 2035 results.

The constraint is also aggregate rather than asset-by-asset: the model matches electrolyser fleet growth to renewable fleet growth within a zone, not individual electrolysers to individual installations.

1.3.3. Temporal correlation (Art. 6)

What is implemented

Both phases of the phase-in are represented: monthly matching until the end of 2029, then hourly matching from 2030. The model constraint stresses that the consumption of the electrolysers and other RFNBO technologies, in a given period (e.g., 1 hour, 1 month), cannot exceed renewable generation in the same period, within the same bidding zone.

The interaction with additionality is explicit. When additionality is active, matching applies only to the additional renewable capacity; when it is deactivated, as in certain policy variants, matching applies to the full renewable fleet.

Caveat on resolution. The model runs at a two-hourly time step, chosen to keep EU-wide runs over six investment periods computationally tractable, so “hourly” matching is enforced at the model’s two-hour resolution. This is slightly more permissive than the regulation, since it allows an hour of surplus to offset an adjacent hour of deficit. This means that the impact on the different metrics of delaying hourly matching could be slightly larger than what is captured in the study.

What is not implemented

- **Storage flexibility** — the provision allowing electricity from a new storage asset behind the same connection point to count towards matching if it is charged during the matching period. Its absence removes a compliance option that would reduce the cost of hourly matching, so the modelled cost of Article 6 is conservative.

- **The low-price exemption**, which automatically waives matching when the day-ahead price falls to €20/MWh or below, or below 0.36 times the CO₂ allowance price. This exemption is expected to bind increasingly often in a system with high renewable penetration, so omitting it could likewise overstate the cost of the criterion in the later horizons. Nevertheless, the exemption criterion set out in the DA (>90% renewable grid, see below) allows for some flexibility in the longer term.

1.3.4. Geographic correlation (Art. 7)

What is implemented

All constraints are enforced on a bidding-zone basis in every scenario. This corresponds to Option A of Article 7 — renewable installation and electrolyser in the same bidding zone — and, where an offshore zone is interconnected to the electrolyser's zone, to Option C. In the model, bidding zones are approximated by the national and nodal regions of the 33-node network, so the criterion is effectively national for most countries.

What is not implemented

- **Option B**, allowing sourcing from an interconnected zone where the day-ahead price in the generating zone is at least as high as in the electrolyser's zone. This is the main flexibility withheld: it would let producers source from a neighbouring zone whenever the price signal indicates no congestion. Relieving the geographic correlation to allow renewables to feed electrolyzers in interconnected zones is investigated in one of the policy variants (see [Section 2.2.8](#)).
- **Article 7.2 Member State flexibility**, allowing stricter sub-zonal location criteria. Not represented, as it depends on national implementing decisions that do not yet exist.

1.3.5. Exemptions and supporting constraints

The two grid-based exemptions are applied as country-level tests on the electricity production mix, excluding imports. Above a 90 % renewable share (Art. 4.1), both additionality and temporal correlation are waived. Below a carbon intensity of 18 gCO₂eq/MJ (Art. 4.2), additionality alone is waived while temporal and geographic correlation continue to apply. A five-year lock-in (sunset clause) follows the crossing of either threshold. The model does not implement the criteria that the RFNBO production should not exceed a maximum number of hours set in relation to the proportion of renewable electricity in the bidding zone (Art. 4.1).

1.3.6. Net effect of the simplifications

The exclusions on the pathway side (Articles 3 and 4.3), those within Article 5 (transitional waiver) and Article 6 (storage flexibility, low-price exemption), and the omission of Option B under Article 7 all remove compliance options available under the regulation as drafted. The modelled regime is therefore systematically stricter than the legal text, and the resulting compliance costs should be read as an upper bound.

2. Results

This section outlines the results of the model introduced previously. First, the scenario corresponding to the Current Regulation is described ([Section 2.1](#)), which is then used as reference to compare the impact of the individual policy variants. Follows a detailed impact assessment of each variant ([Section 2.2](#)), along with a cross-cutting comparison between variants ([Section 2.3](#)).

Before presenting the results, an important disclaimer should be made. A cost-optimisation model indicates where the system is heading and how policy options compare with one another; it does not describe real life, and the absolute figures it produces are **orders of magnitude rather than forecasts**. Five features of the modelling framework warrant particular caution. First, the model operates under **myopic foresight**: it optimises each five-year investment period sequentially, without anticipating future regulatory changes, so installed capacities are indicative. Second, **most hydrogen demand drivers are set exogenously**, whereas real demand responds to prices — the price–volume feedback is therefore limited. Third, **costs, efficiencies and learning curves are uncertain projections**, and the results inherit those parameter biases, making CAPEX and price levels indicative. Fourth, **hydrogen import prices and volume caps**, although selected after a literature review, **remain uncertain and vary widely across studies**; they strongly shape domestic production, particularly around 2035. Fifth, all scenarios follow the EU net-zero trajectory, which caps the emission differences any variant can produce; emission effects are therefore lower bounds. The results are accordingly suited to reading the direction and sign of effects, ranking the policy variants against one another, and identifying orders of magnitude and systemic mechanisms such as renewable cannibalisation. Without further sensitivity analysis, they should not be used to claim precise evolutions of hydrogen or electricity prices, to treat single-scenario outcomes as forecasts, or to read small differences between variants as significant.

2.1. Current Regulation Scenario

The purpose of the Current Regulation scenario within this study is to **serve as reference scenario to which all other policy variants are compared**, to understand the impact of relaxing certain dimensions of the delegated act. The Current Regulation scenario enforces requirements of the current state of the delegated act, as detailed in [Section 1.3](#). **The Current Regulation scenario characterises where the system is heading under the act as it stands** (H₂ mix, RES build-out, LCOH, electricity prices). It should be read as a trajectory, not a forecast. In this section, we analyse key metrics characterising this trajectory.

Methodological Note – Why the Current Regulation scenario should not be compared to a baseline scenario without regulation

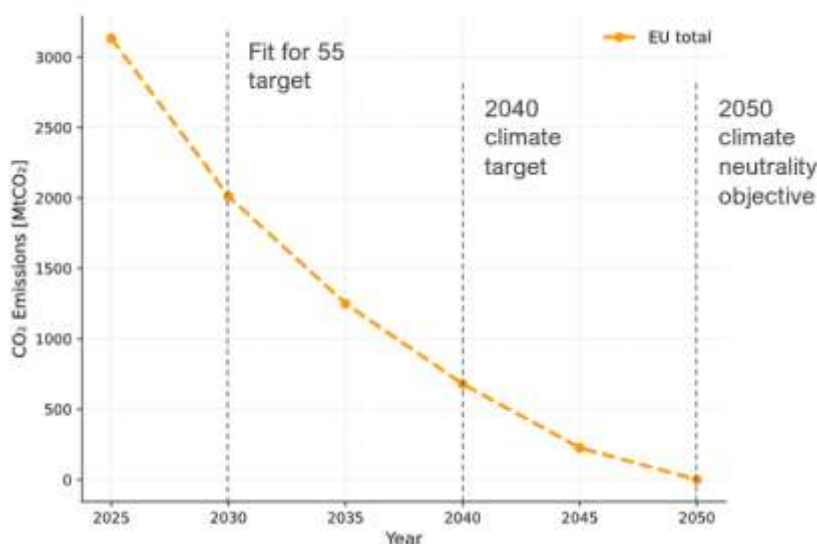
The baseline is not a policy counterfactual and should not be read as a "world without regulation". It is a technical reference run that serves two instrumental purposes: it produces the CO₂ cost trajectory and the RFNBO volumes that are then imposed exogenously on all regulated runs, and it defines the renewable capacity level against which the additionality criterion (Art. 5) is enforced. Because of this, the baseline and the Current Regulation scenario do not differ only by the presence of the delegated

act: they differ in how the carbon constraint is formulated (emission targets binding in the baseline, translated into imposed national CO₂ prices in the regulated runs) and in whether RFNBO production exists at all. A baseline-to-CR delta would therefore conflate the effect of the regulation with a change in model formulation, and could not be attributed to the policy. Conversely, all policy variants are built on the same baseline, inherit the same CO₂ price trajectory and the same hydrogen demand, and differ from the Current Regulation scenario only in the regulatory parameters that are deliberately altered. The resulting differences are attributable to the regulatory change itself. This is also the policy-relevant framing: the question raised by the five Member States is not whether the delegated act should exist, but what would happen if its provisions were amended — so the Current Regulation scenario is the counterfactual against which every variant is assessed.

2.1.1. Evolution of CO₂ emissions

The Current Regulation scenario is a **net-zero scenario**. All Member States are constrained to follow the EU climate trajectory — Fit for 55 in 2030, the 2040 climate target, and climate neutrality in 2050 — enforced through steadily increasing national CO₂ prices rather than hard caps. This is a deliberate choice, not a background assumption: **RFNBOs only have a reason to exist in a decarbonising system**. In a world without a binding carbon constraint, **fossil-based hydrogen remains the cheaper option indefinitely and renewable hydrogen never emerges**. Assessing the act therefore requires a context in which its object — renewable hydrogen — is actually needed. The CO₂ price trajectory that drives this decarbonisation is also the main mechanism triggering the switch from SMR to electrolysis in the 2030–2035 period.

Figure 3 – Evolution of total CO₂ emissions in the EU (model output, Current Regulation scenario)



Under a less ambitious decarbonisation path, the deltas between the variants and the Current Regulation would not simply scale — they would change in composition. Grids would remain carbon-intensive for longer, so the exemption thresholds would be crossed later or not at all, and the variants that relax them

(relaxed carbon intensity exemption, relaxed renewable share exemption) would expose electrolyzers to a substantially dirtier marginal mix. The protective function of the three pillars is strongest precisely when the marginal plant is fossil, which is the situation our scenario exits early. **The emission impacts reported here should therefore be read as a lower bound on the systemic risk of relaxing the safeguards**, rather than as a full measure of it. In the opposite direction, a weaker carbon constraint would also mean far lower RFNBO volumes overall, since the CO₂ price is the main driver of the switch away from SMR — so the absolute stakes of the regulatory debate would shrink on the hydrogen side even as the per-unit emission risk of each relaxation grows.

2.1.2. Renewable penetration

The net-zero constraint described above has a direct and structural consequence for the regulation: as countries decarbonise their power sector to meet the EU trajectory, they mechanically cross the thresholds that trigger the Article 4.1 and 4.2 exemptions. The two charts show when this happens. Grid carbon intensity falls fastest: France, Spain and Denmark are already below 18 gCO₂eq/MJ in 2025, and by 2035 essentially all modelled countries have crossed the threshold. The renewable share criterion is met later, since it also excludes nuclear and residual fossil generation — Spain and Denmark exceed 90% by 2030, the Netherlands and Great Britain around 2030–2035, and most remaining countries between 2035 and 2045; Czechia is the only one that does not reach it within the horizon, plateauing just below 90%. Because the model applies a five-year lag between the moment a country crosses a threshold and the investment period in which the exemption becomes effective, the widespread crossing of the 18 gCO₂eq/MJ threshold in 2035 translates into an exemption from additionality from the 2040 investment period onwards, with an indirect effect on temporal correlation, which then applies to the whole renewable fleet rather than to dedicated additional capacity.

Figure 4 – Share of renewables within countries' electricity production (*model output, Current Regulation scenario*). Only 10 representative countries are shown for conciseness.

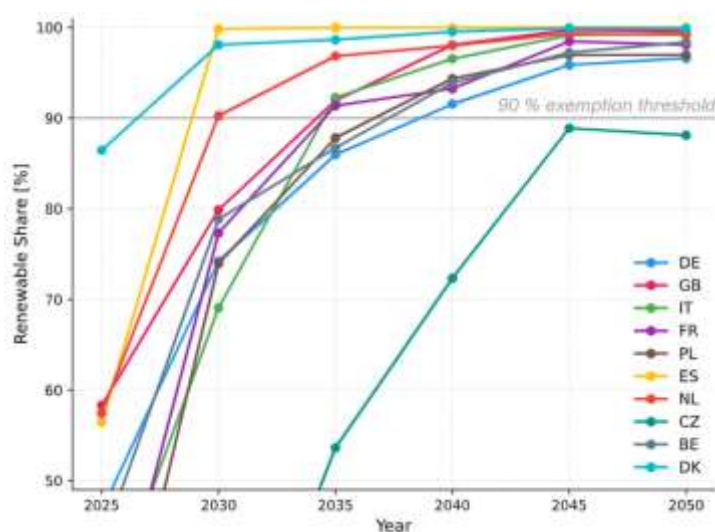
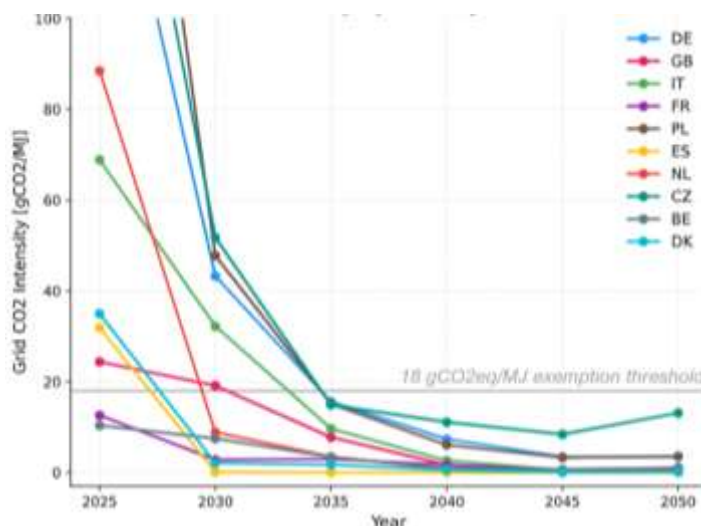


Figure 5 – Carbon intensity of countries' electricity mix (model output, Current Regulation scenario)
Only 10 representative countries are shown for conciseness.



Combined with the renewable-share exemption, this means that **from 2040 most producing countries operate outside the default three-pillar pathway. The regulation's binding period is therefore narrow: it is concentrated on 2030–2040**, precisely the window in which renewable hydrogen production begins to scale.

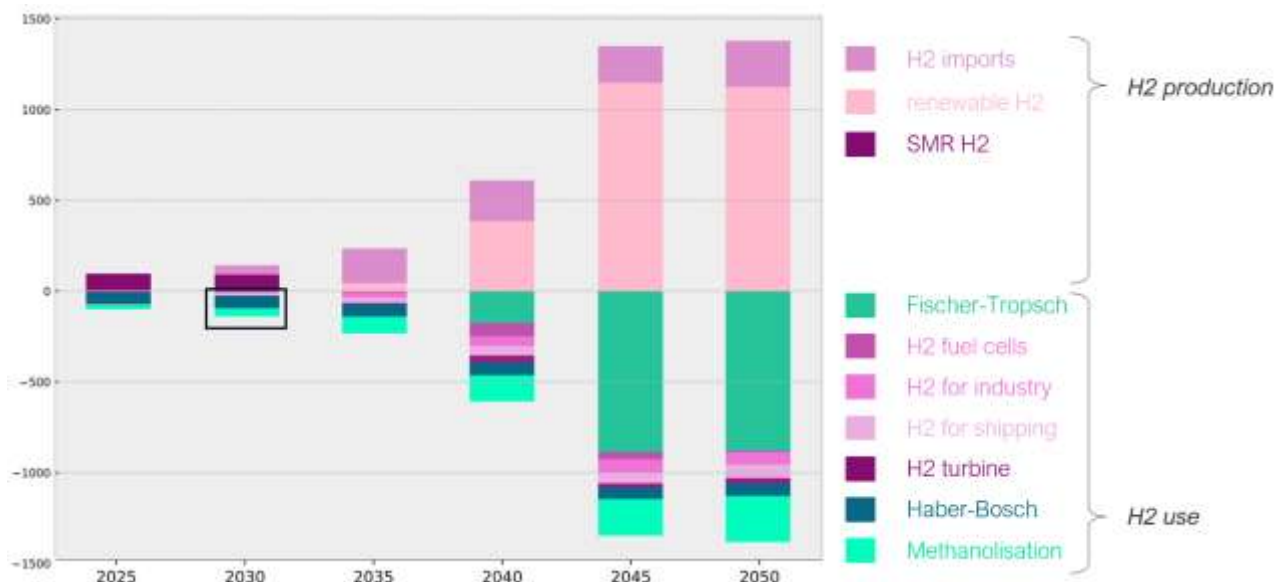
To note, the grid intensity and renewable share values for each country have been validated against Electricity Maps values [9] to assess the model plausibility for 2025, with a good correspondence for most geographies, with a noteworthy deviation for Belgium (because the PyPSA-RFNBO model does not faithfully represent the 2025 Belgian energy system).

2.1.3. Evolution of H₂ production and use

Overall H₂ production and use

Regarding the modelled H₂ total production, two phases stand out. Until 2035, total H₂ volumes remain modest (roughly 100–230 TWh/year) and hydrogen is almost entirely absorbed by existing chemical demand — ammonia via Haber-Bosch and methanol. Supply over this period is still largely fossil: SMR dominates in 2025–2030, and renewable H₂ stays below 1 Mt, with imports filling part of the gap. This matters for the regulation, since RFNBO criteria already apply to the downstream methanol and ammonia production steps in 2030, at a point where domestically produced renewable hydrogen is not yet available at scale. From 2035 onwards the picture changes: rising CO₂ prices make SMR uncompetitive, renewable H₂ takes over as the main domestic source, and imports are exploited close to their assumed cap. Total volumes then grow sharply — around 600 TWh in 2040 and about 1,350 TWh from 2045 — driven almost entirely by Fischer-Tropsch synthesis of liquid hydrocarbons for aviation, complemented by shipping fuels, industrial uses and hydrogen turbines. In other words, near-term hydrogen demand is a chemical-feedstock story, while the long-term expansion is an e-fuels story.

Figure 6 – Evolution of the modelled hydrogen production (top) and use (bottom) in the EU [TWh]



Both the level and the timing of this expansion should be read as indicative. Import volumes and prices are assumptions drawn from a literature review with wide dispersion, and they strongly shape how much hydrogen is produced domestically — particularly around 2035. Hydrogen demand is also largely exogenous, so it does not react to the price effects of the delegated act.

Renewable H2 production

At EU level, production is essentially negligible until 2030, reaches around 1.5 Mt in 2035, then accelerates sharply to roughly 12 Mt in 2040 and 34.5 Mt in 2045, before plateauing to 2050. The national breakdown shows that this ramp-up is not uniform, and that its sequencing is driven by the interaction between the regulation and each grid's resource mix. Wind-dominated grids move first: the Netherlands, Great Britain and Denmark are the only meaningful producers in 2035, because their higher and more stable capacity factors reduce the utilisation penalty imposed by hourly matching (see Insight box below)⁵. From 2040 onwards, PV-intensive grids enter the picture — Italy reaches about 5.5 Mt and Spain about 2.3 Mt by 2045 — precisely because the carbon-intensity and renewable-share exemptions have by then been triggered, releasing them from the hourly matching requirement that their solar profiles cannot economically satisfy. France follows a similar logic through the Article 4.2 low-carbon threshold, reaching close to 4 Mt. Great Britain remains the dominant producer throughout, at over 10 Mt in 2050. The distribution therefore reflects regulatory design as much as renewable potential: the exemption thresholds are what allow southern, PV-dominated grids to participate at all.

⁵ Norway, which appears in many studies as a strong candidate for RFNBO production, does not stand out in our model. The main reason is that for the meteorological year under consideration (2013), the wind potential curves are not favourable. This artifact therefore demonstrates that the model is not intended to predict the optimal distribution of RFNBO production in Europe in this case.

Figure 7 – Total renewable H2 produced in the model

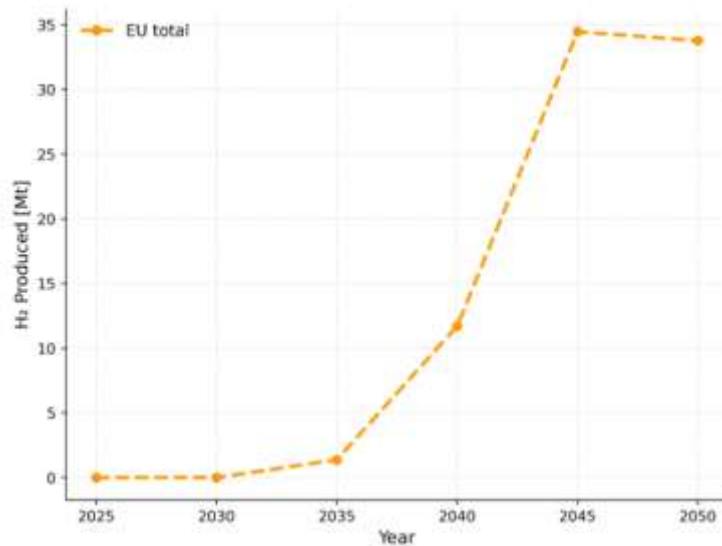
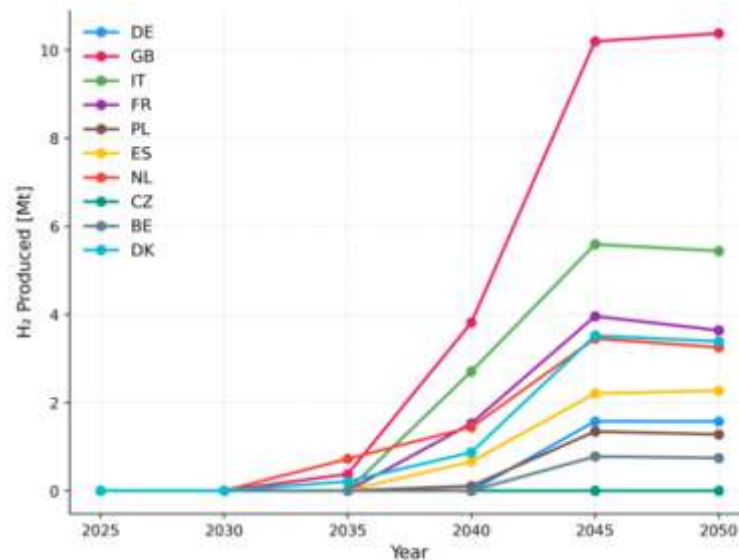


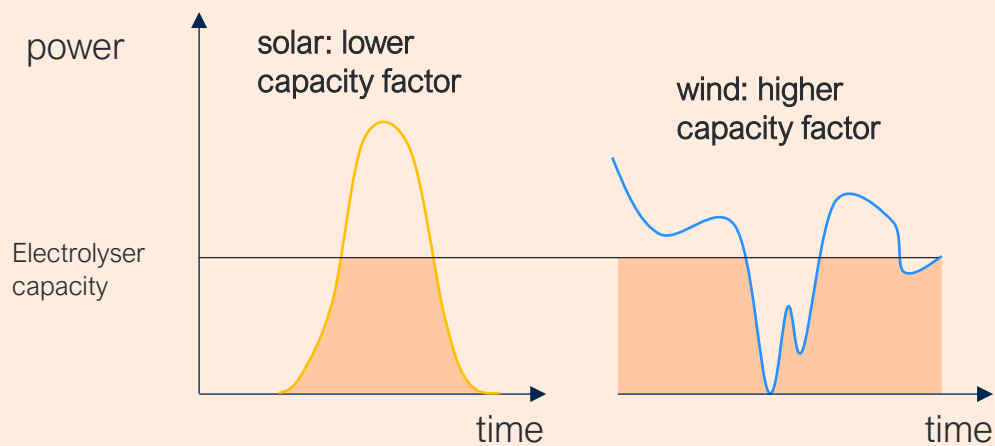
Figure 8 - Renewable H2 produced in the model, per country



Insight – Why wind dominated grids are better positioned to respond to hourly matching requirements

Under hourly matching, the electrolyser's consumption in any given hour cannot exceed the renewable electricity generated in that same hour by the assets it is contracted with. The generation profile of those assets therefore dictates the electrolyser's operating profile, and this is where wind

and solar diverge. Solar output is concentrated in a narrow band of hours around midday and falls to zero every night, with a pronounced seasonal swing on top. Sizing an electrolyser to absorb the midday peak means it sits idle most of the year; sizing it smaller means the top of the peak is spilled or sold to the grid rather than converted. As the figure illustrates, only the shaded portion of the profile is usable, and for solar that portion covers a small share of the hours in the year. Wind generation, by contrast, is spread more evenly across the day and the seasons, so an electrolyser sized near the typical output level can run through a much larger number of hours. Because electrolyser CAPEX is amortised over the kilograms actually produced, a higher number of full-load hours translates directly into a lower Levelized Cost Of Hydrogen (LCOH). This is why wind-dominated grids (NL, GB, DK) can comply with hourly matching at an acceptable cost and start producing first, while PV-dominated grids (IT, ES) only become viable once the Article 4.1 and 4.2 exemptions waive the hourly requirement for them.



2.2. Policy variants

Eight different policy variants are investigated in order to study the individual and combined impact of relaxing different requirements of the regulation. The variants cover delayed additionality requirement (VAR-A1), delayed (VAR-T1) and removed (VAR-T1-bis) hourly matching requirement, relaxed carbon intensity (VAR-A2) and renewable share (VAR-SUN) exemption thresholds, an interpretation of the five Member States' proposal in their joint letter to the European Commission, combining a delay in additionality, hourly matching and relaxed exemption thresholds (VAR-MS), a relaxed geographic correlation allowing sourcing from interconnected zones (INT), and — in the other direction — the removal of the exemptions altogether (CR-force).

Table 3 – Description of the 8 policy variants investigated in this study

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028 ¹	From monthly to hourly from 2030	Same bidding zone
CR-force	Removed exemptions	From 2028 ¹ , with carbon intensity and renewable share exemptions removed	From monthly to hourly from 2030, with renewable share exemption removed	Same bidding zone
VAR-A1	Delayed additionality	From 2040	From monthly to hourly from 2030	Same bidding zone
VAR-T1	Delayed hourly matching	From 2028 ¹	From monthly to hourly from 2040	Same bidding zone
VAR-T1-bis	Perpetual monthly matching	From 2028 ¹	Monthly until 2050	Same bidding zone
VAR-A2	Relaxed carbon intensity exemption	From 2028 ¹ with carbon intensity exemption relaxed from 18 to 36gCO ₂ eq/MJ	From monthly to hourly from 2030	Same bidding zone
VAR-SUN	Relaxed renewable share exemption	From 2028 ¹ with renewable share exemption relaxed from 90 to 80 %	From monthly to hourly from 2030, with renewable share exemption relaxed from 90 to 80 %	Same bidding zone
VAR-MS	Combined additionality and hourly matching delay with relaxed exemption thresholds	From 2040, with renewable share exemption relaxed from 90 to 80 %	From monthly to hourly from 2040, with renewable share exemption relaxed from 90 to 80 %	Same bidding zone
INT	Interconnected zones	From 2028 ¹	From monthly to hourly from 2030	Directly connected countries, at all times ²
Remark	¹ The model only models investments every 5 years, starting from 2025. The 2028 shift is thus captured in 2030. ² Even when price conditions of Article 7(1)b are not met			

The impact of each variant is assessed through five metrics extracted at years 2025, 2030, 2035, 2040, 2045 and 2050, both at country and EU level:

- **Investments in renewable capacity, in bn€:** The total investment in renewable electricity production over the given year, per country and at EU level (mainly wind turbines and solar panels). The scope includes all capacity, not only those dedicated to the RFNBO production.
- **CO₂ emissions, in MtCO₂e:** The total net CO₂ emissions over the given year, per country and at EU level
- **Marginal electricity price, in €/MWh:** the cost of supplying one additional MWh. It does not correspond to the market price, as it excludes taxes, grid tariffs and scarcity rents from real markets. It is reported here as time- and demand-weighted average over the given year, per bidding zone and at EU level.
- **Renewable hydrogen production volume, in Mtons:** the total volume of grid-connected renewable hydrogen produced over the given year, per country and at EU level
- **Levelised Cost of Renewable Hydrogen (LCOH), in €/kg H₂:** the annualised CAPEX plus fixed and variable operating costs, (dominated by electricity costs), divided by annual hydrogen output. The metric is averaged over the given year, per bidding zone and at EU level. At EU-level, it is given both as cross-country average and weighted average by country production volume.

All metrics are assessed by analyzing their delta compared to the Current Regulation scenario.

Disclaimer

The LCOH should not be analyzed prior to 2030, as the corresponding volumes of renewable hydrogen are negligible.

2.2.1. Removed exemptions (CR-force)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028	From monthly to hourly from 2030	Same bidding zone
CR-force	Removed exemptions	From 2028, with carbon intensity and renewable share exemptions removed	From monthly to hourly from 2030, with renewable share exemption removed	Same bidding zone

This variant is stricter than the current regulation: the exemptions based on grid carbon intensity and on the renewable share of the production mix are removed, so additionality and hourly matching keep applying to every grid over the whole horizon. Compared to the Current Regulation scenario, investment in renewables increases continuously to serve the RFNBO clean electricity demand — +2% (5 bn€) in 2030 and +9% (40 bn€) in 2050, an increase driven by compliance rather than by least-cost decarbonisation — with a large build-out in wind-dominated grids and a drop in PV-dominated ones. Net emissions decrease marginally in 2030 and 2035 (-0.3% and -0.2%) thanks to that renewable penetration, then increase in 2040 and 2045

(+1.4% and +6.4%), most likely because RFNBO production becomes insufficient to serve the e-fuel and feedstock demand, which is then met by fossil-based alternatives. Mean EU marginal electricity costs fall continuously, from -6% in 2035 to -22% in 2050. Grid-connected H₂ production rises in wind-dominated grids and falls in PV-dominated ones, with a net decrease at EU level (-12 TWh in 2035, -87 TWh in 2040). In the main producing grids, cheaper electricity more than offsets the lower capacity factors, so the mean EU LCOH decreases as well (-9% in 2035, -12% in 2045-2050).

The exemptions are designed to protect grids that already hold a significant share of renewables from requirements that would be disproportionate for them. Removing them forces these grids into an expensive renewable build-out to keep meeting additionality and temporal correlation. Wind-dominated systems absorb the constraint thanks to their higher capacity factors, with production increasing and LCOH decreasing, whereas production collapses in PV-dominated grids, which cannot economically satisfy a permanent hourly matching requirement. The exemptions are therefore useful both to protect PV-dominated grids from disproportionate requirements and to avoid over-investment overall. Effects become visible from 2030, once domestic RFNBO methanol and ammonia production has started, and unfold until 2050.

Figure 9 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Removed exemptions - CR-force, by country [bn€]

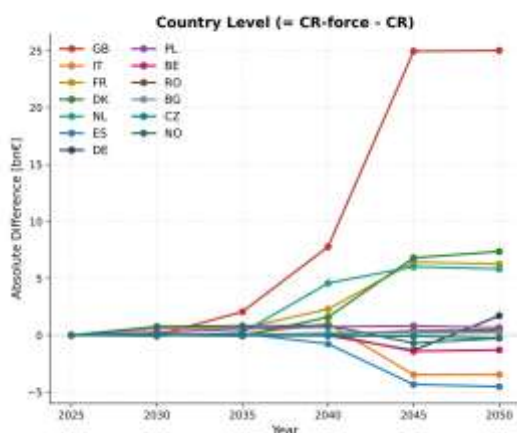


Figure 10 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Removed exemptions - CR-force, EU total [bn€]

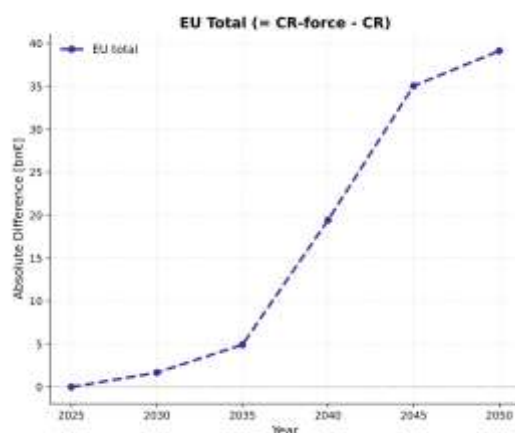


Figure 11 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Removed exemptions - CR-force, by country [MtCO2]

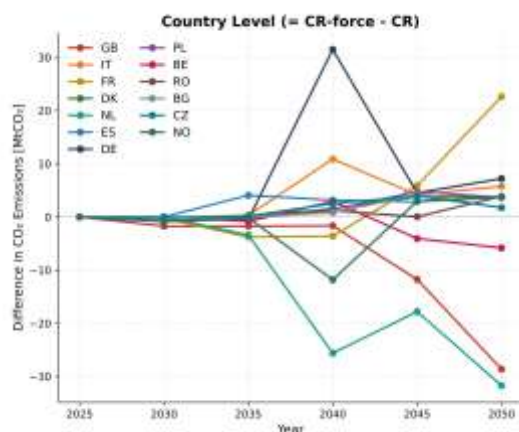


Figure 12 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Removed exemptions - CR-force, EU total [MtCO2]

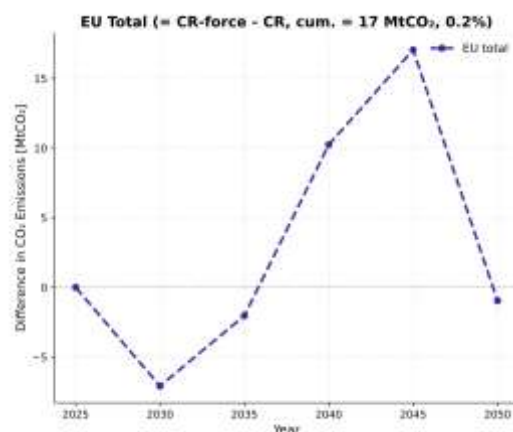


Figure 13 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Removed exemptions - CR-force, by country [€/MWh]

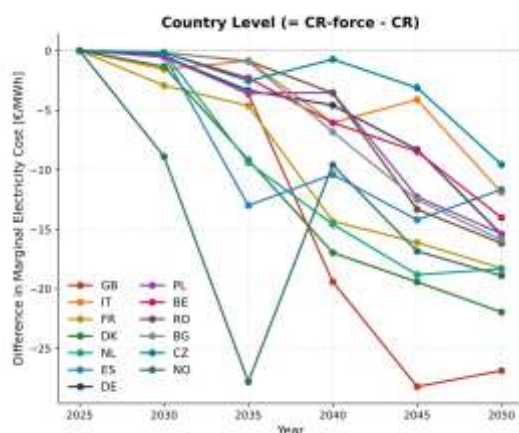


Figure 14 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Removed exemptions - CR-force, EU average [€/MWh]

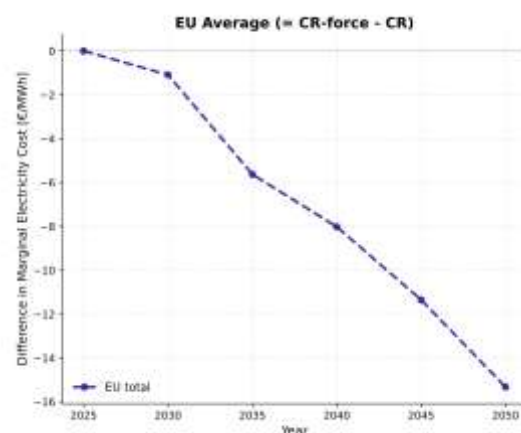


Figure 15 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Removed exemptions - CR-force, by country [TWh]

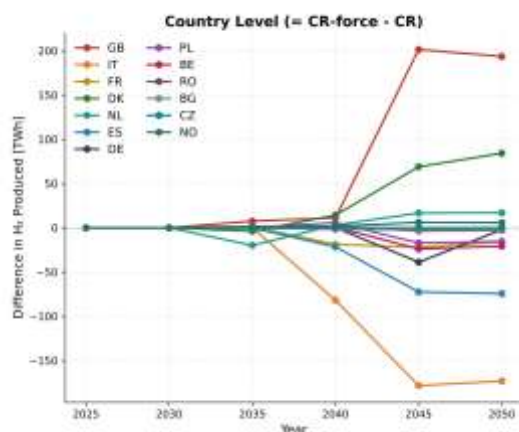


Figure 16 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Removed exemptions - CR-force, EU total [TWh]

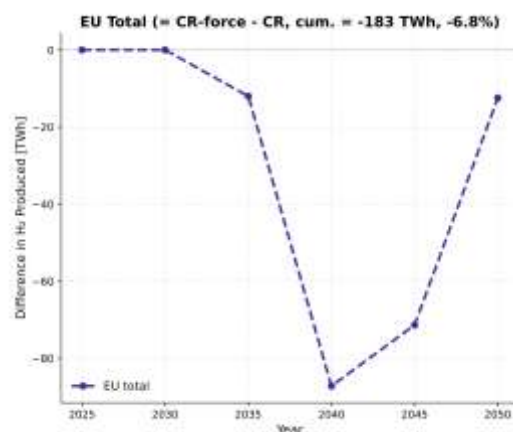


Figure 17 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Removed exemptions - CR-force, by country [€/MWh]

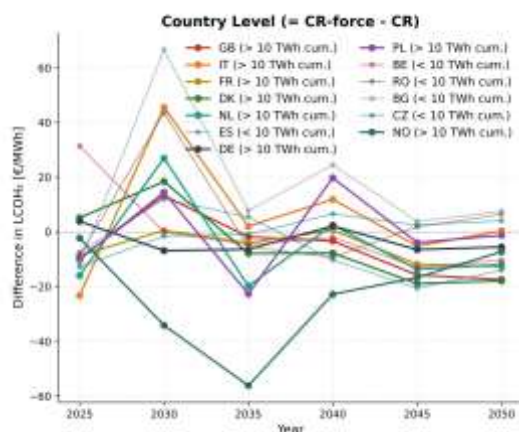
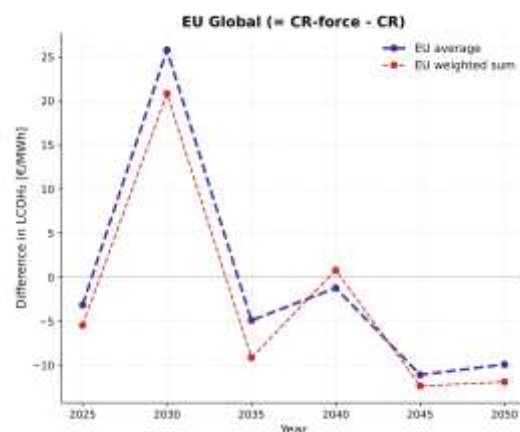


Figure 18 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Removed exemptions - CR-force, EU average [€/MWh]



2.2.2. Delayed additionality (VAR-A1)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
<i>CR</i>	<i>Current Regulation</i>	<i>From 2028</i>	<i>From monthly to hourly from 2030</i>	<i>Same bidding zone</i>
VAR-A1	Delayed additionality	From 2040	From monthly to hourly from 2030	Same bidding zone

In this variant, additionality is enforced from 2040 instead of 2028. Because the whole renewable fleet — and not only additional capacity — then becomes eligible, the temporal correlation requirement is indirectly weakened as well. Investment in renewables decreases slightly in 2030 and 2035 (around -1.5%, or -3 bn€), and emissions increase marginally over the same years (+0.5% and +0.2%). Mean EU marginal electricity prices rise by 1 to 2%, reflecting both the lower renewable penetration and the additional demand from higher H₂ production. In 2035, production shifts towards grids with high capacity factors that were subjected to the constraint in the Current Regulation scenario — Great Britain in particular, thanks to offshore wind — and total EU production increases (about 0.4 Mt). The LCOH effect is strongly grid-dependent: it rises slightly where production expands (+4% in Great Britain, driven by electricity prices), while the EU average drops by 3%.

Opening eligibility to the entire renewable fleet allows production to develop in countries that were previously constrained by additionality. However, since no additional renewable capacity is built in response, this extra demand is served by the existing mix and pushes electricity prices up. The variant mostly affects the 2035 investment period, during which the constraint was previously binding and renewable H₂ production has already started to scale. From 2040 the effects fade, as most countries are exempted from additionality in any case.

Figure 19 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Delayed additionality - VAR-A1, by country [bn€]

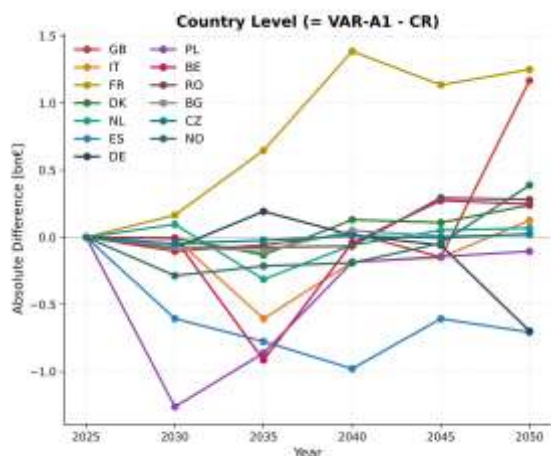


Figure 20 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Delayed additionality - VAR-A1, EU total [bn€]

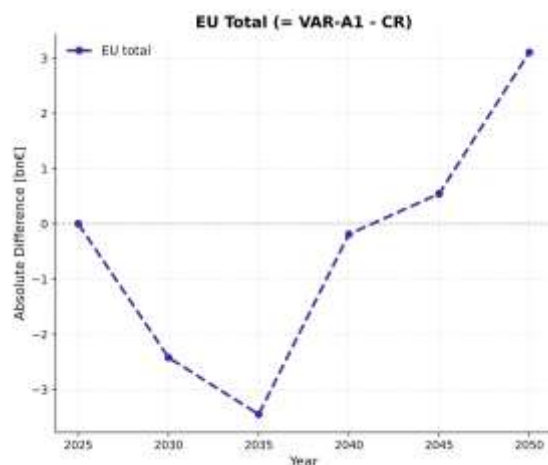


Figure 21 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Delayed additionality - VAR-A1, by country [MtCO2]

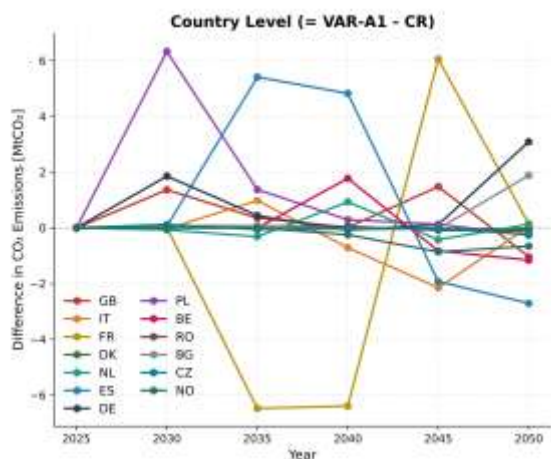


Figure 22 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Delayed additionality - VAR-A1, EU total [MtCO2]

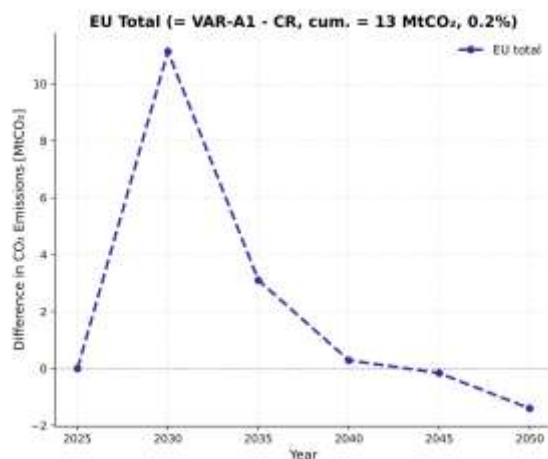


Figure 23 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Delayed additionality - VAR-A1, by country [€/MWh]

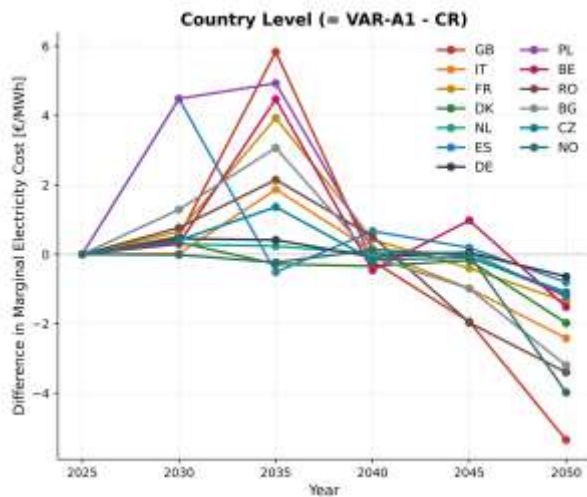


Figure 24 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Delayed additionality - VAR-A1, EU average [€/MWh]

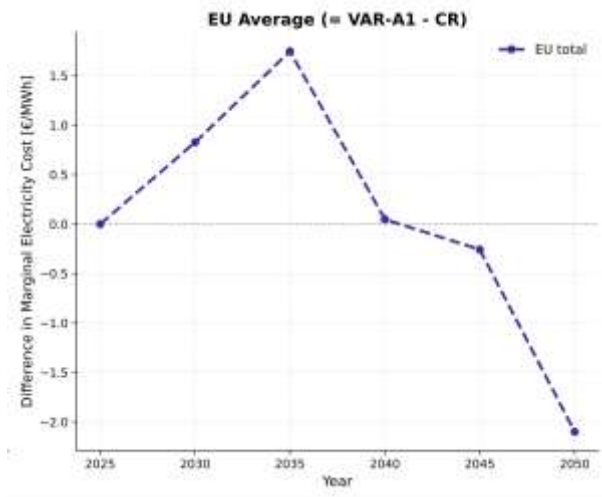


Figure 25 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Delayed additionality - VAR-A1, by country [TWh]

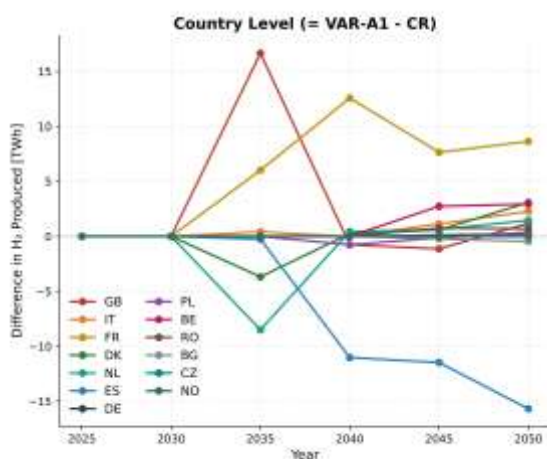


Figure 26 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Delayed additionality - VAR-A1, EU total [TWh]

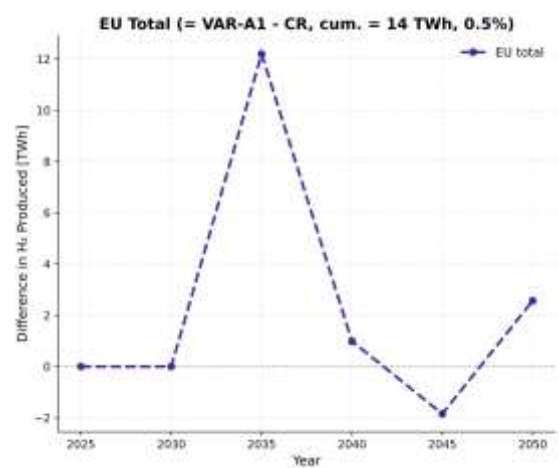


Figure 27 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Delayed additionality - VAR-A1, by country [€/MWh]

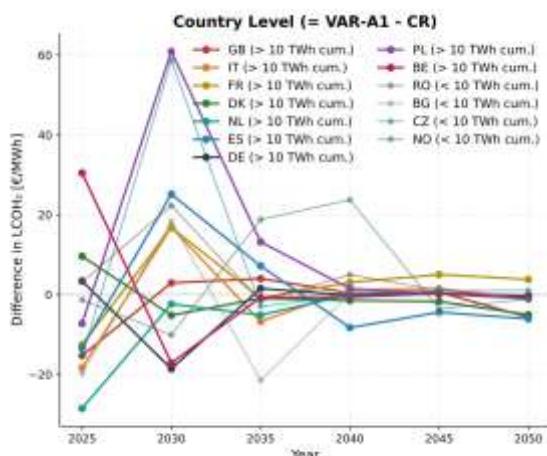
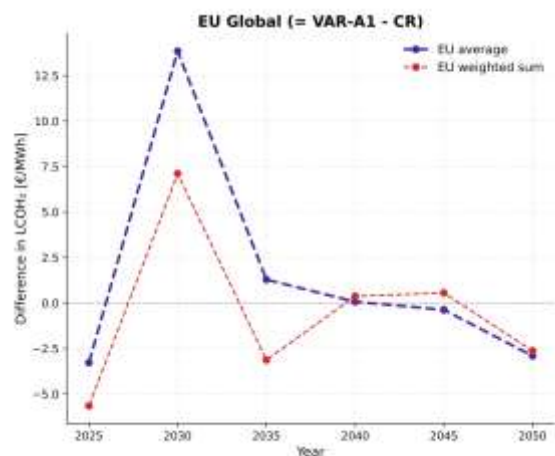


Figure 28 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Delayed additionality - VAR-A1, EU average [€/MWh]



2.2.3. Delayed hourly matching (VAR-T1)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028	From monthly to hourly from 2030	Same bidding zone
VAR-T1	Delayed hourly matching	From 2028	From monthly to hourly from 2040	Same bidding zone

In this variant, temporal correlation switches from monthly to hourly matching in 2040 instead of 2030. Investment in renewables decreases slightly around 2030 and 2035 (about -0.5%), less than under delayed additionality, and emissions increase marginally in 2030 (+0.3%). Mean EU marginal electricity prices rise by around 0.5% in 2035. In that year, production shifts towards grids with high capacity factors that were not previously exempted: alongside wind-intensive systems such as Great Britain, PV-intensive grids also expand their output, and total EU production increases by 34% in 2035. The LCOH is stable or decreasing in most top producing grids — -7% in Italy, broadly stable in Great Britain — and -7% at EU level.

The effects resemble those of delayed additionality but with a smaller magnitude: because additionality is maintained, part of the renewable investment is preserved. The difference lies in the PV-dominated grids, which were previously excluded by hourly matching and now reach higher capacity factors and more competitive costs. Delaying hourly matching therefore improves electrolyser utilisation and lowers the LCOH. However, the gain is temporary and comes with lower renewable investment and higher electricity prices over the same years. As for VAR-A1, effects concentrate on the 2035 investment period; from 2040 most countries are exempted from hourly matching anyway and the variant converges towards the current regulation.

Figure 29 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, by country [bn€]

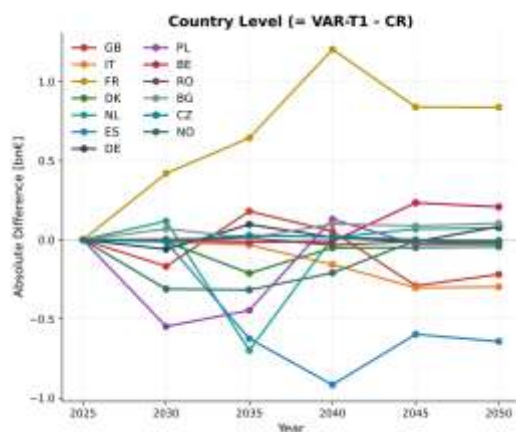


Figure 30 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, EU total [bn€]



Figure 31 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, by country [MtCO2]

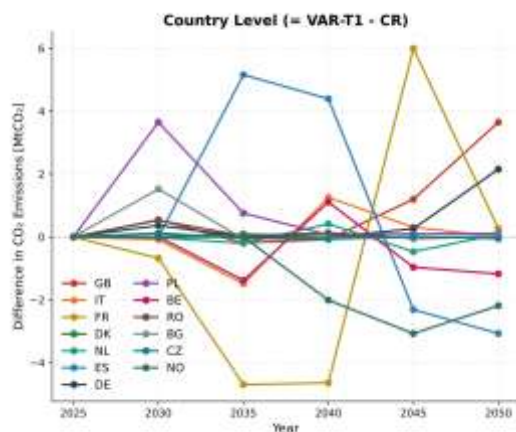


Figure 32 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, EU total [MtCO2]

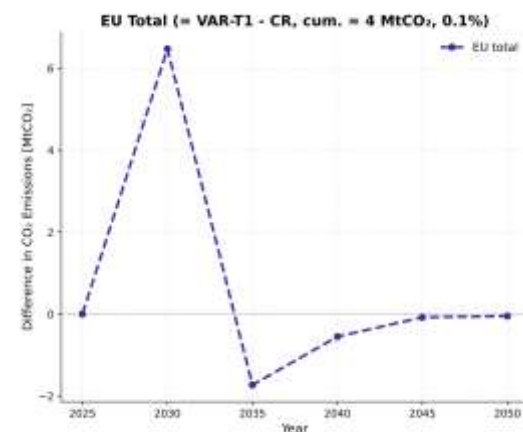


Figure 33 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, by country [€/MWh]

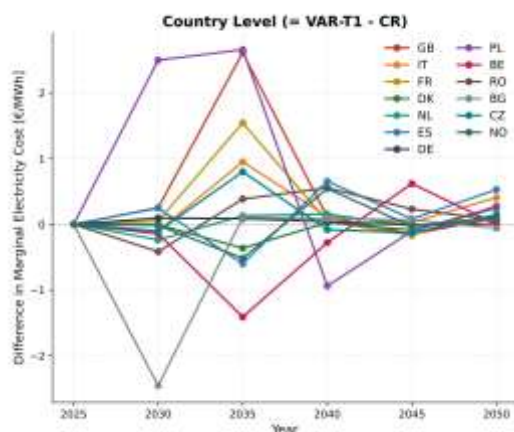


Figure 34 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, EU average [€/MWh]

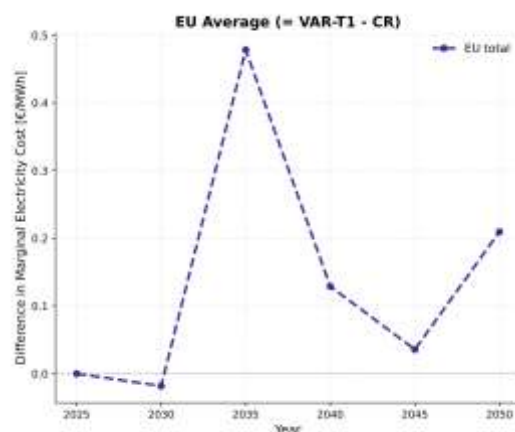


Figure 35 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, by country [TWh]

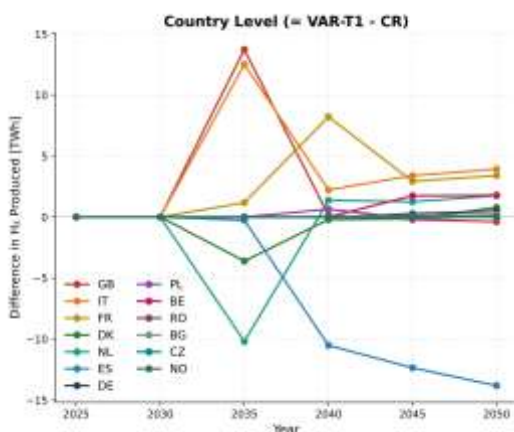


Figure 36 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, EU total [TWh]

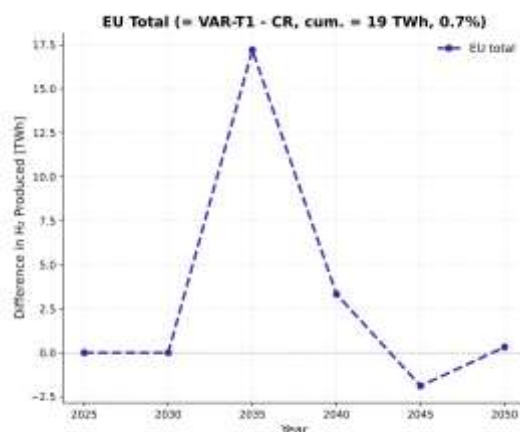


Figure 37 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, by country [€/MWh]

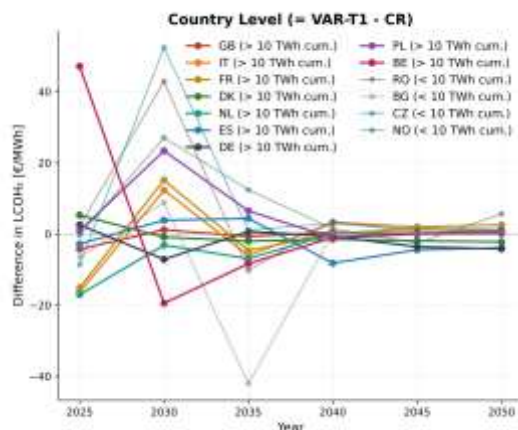


Figure 38 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Delayed hourly matching - VAR-T1, EU average [€/MWh]



2.2.4. Perpetual monthly matching (VAR-T1-bis)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028	From monthly to hourly from 2030	Same bidding zone
VAR-T1-bis	Perpetual monthly matching	From 2028	Monthly until 2050	Same bidding zone

In this variant, instead of switching from monthly to hourly matching, monthly matching is maintained until 2050. The modelled effects are close to those of the delayed hourly matching variant, although slightly worse on systemic impacts: investment in renewables decreases by around 0.5% in 2030 and 2035, emissions increase by 0.3% in 2030, and mean EU marginal electricity prices rise by about 0.5% in 2035. Total EU H₂ production increases by 34% in 2035, as production shifts towards grids with high capacity factors that were not previously exempted, before partly moving away from PV-intensive grids around 2040. The LCOH decreases in most top producing grids, mainly through lower CAPEX allowed by improved capacity factors, with a 7% drop at EU level.

Permanently preserving monthly matching points in the same direction as delaying additionality, again with a smaller magnitude since additionality keeps driving part of the renewable investment. The grids that benefit most are the PV-dominated ones that were not exempted, whose electrolyzers now operate at higher capacity factors. Here too the 2035 investment period is the most affected; beyond 2040, most countries are exempted from hourly matching in any case, which limits the difference with the current regulation. The two options are not equivalent in risk terms: a delay restores hourly matching at a fixed date,

whereas perpetual monthly matching leaves the safeguard entirely dependent on the exemption thresholds being maintained.

Figure 39 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, by country [bn€]

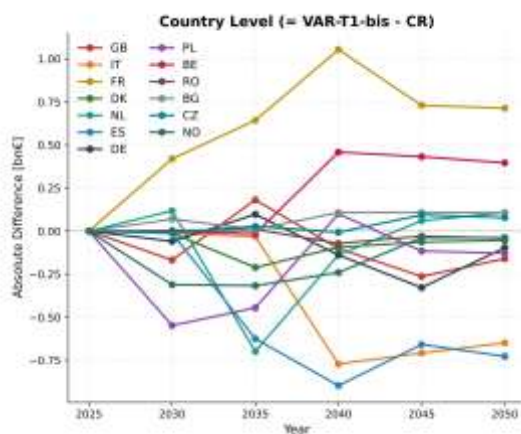


Figure 40 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, EU total [bn€]

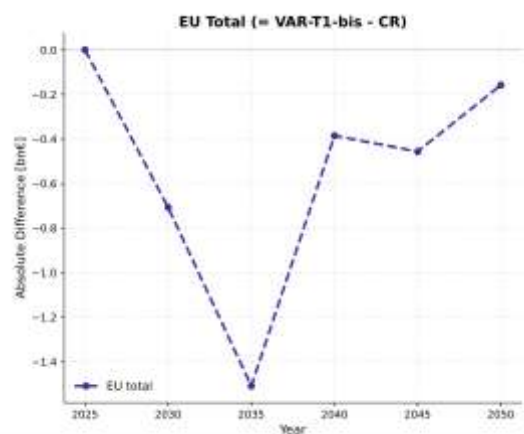


Figure 41 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, by country [MtCO2]

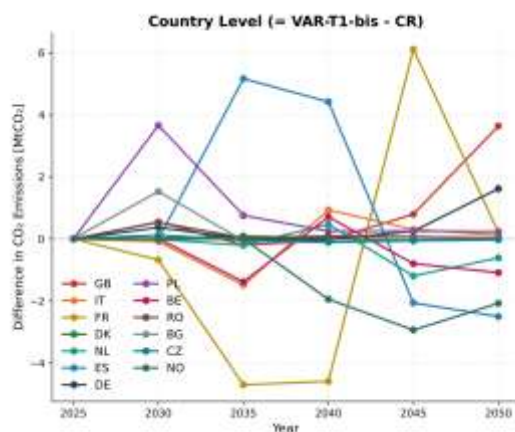


Figure 42 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, EU total [MtCO2]

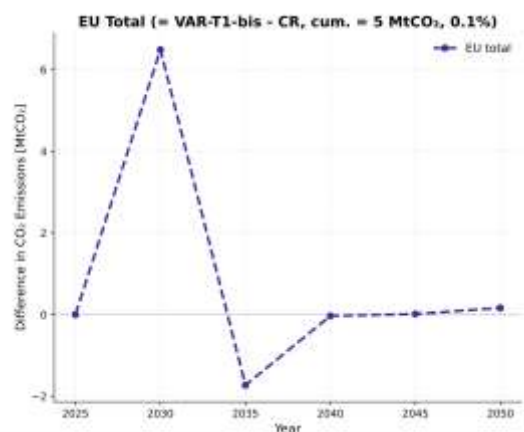


Figure 43 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, by country [€/MWh]

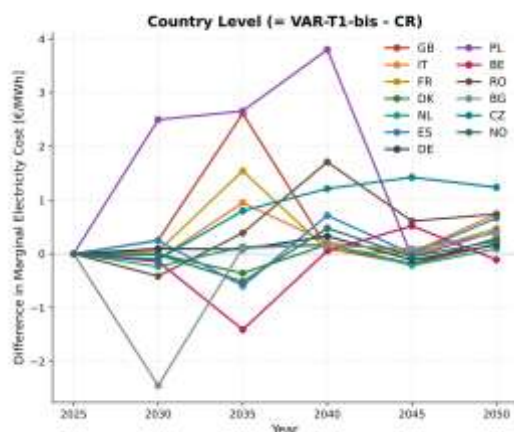


Figure 44 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, EU average [€/MWh]

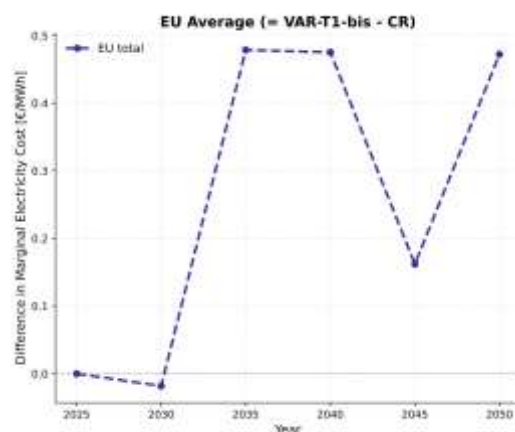


Figure 45 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, by country [TWh]

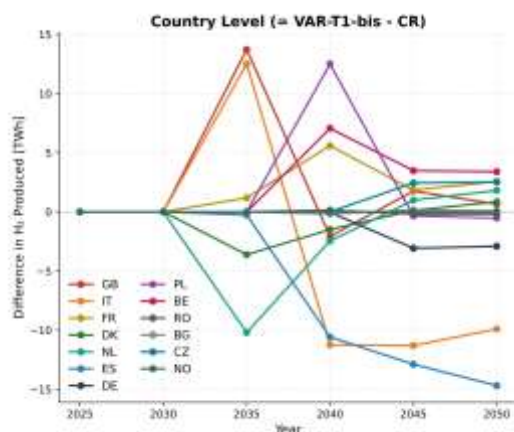


Figure 46 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, EU total [TWh]

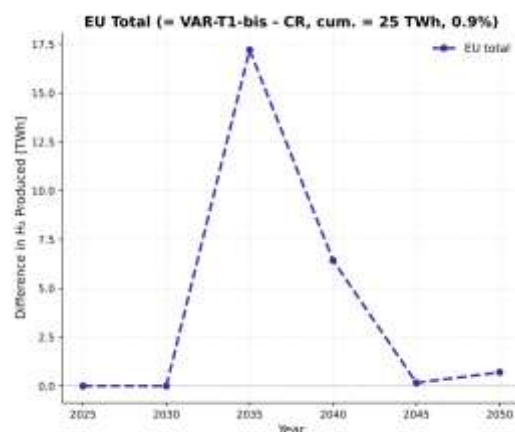


Figure 47 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, by country [€/MWh]

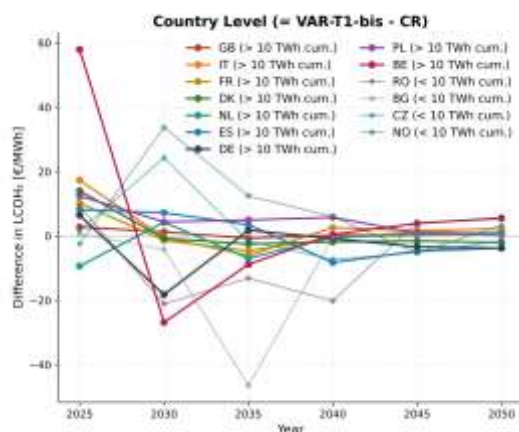


Figure 48 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Perpetual monthly matching - VAR-T1-bis, EU average [€/MWh]



2.2.5. Relaxed carbon intensity exemption (VAR-A2)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028	From monthly to hourly from 2030	Same bidding zone
VAR-A2	Relaxed carbon intensity exemption	From 2028 with carbon intensity exemption relaxed from 18 to 36gCO ₂ eq/MJ	From monthly to hourly from 2030	Same bidding zone

In this variant, the additionality requirement is waived when grid carbon intensity falls below 36 gCO₂eq/MJ, instead of 18 gCO₂eq/MJ in the current regulation. The effects are negligible across all metrics: renewable investment moves by -0.02% in 2035 and +0.08% in 2040, emissions by +0.05 Mt in 2035 and -0.5 Mt in 2040, and mean EU marginal prices by less than 0.1%. Great Britain, which becomes exempted from additionality in 2035 under the relaxed threshold, shows a very small production increase (below 0.1 TWh), and the effect on the LCOH is barely perceptible.

This near-absence of impact follows directly from the ambition of the underlying scenario. Under the current regulation, most countries already fall below 18 gCO₂eq/MJ in 2035 and are therefore exempted from the 2040 investment period, and Great Britain was the only top producer still slightly above the threshold in 2035. Relaxing it thus has very little left to relax, and the most perceptible effects appear in 2040. This result should not be read as an argument for weakening the criterion: in a context where power sector decarbonisation is slower than modelled here, the 18 gCO₂eq/MJ threshold remains an important safeguard.

Figure 49 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, by country [bn€]

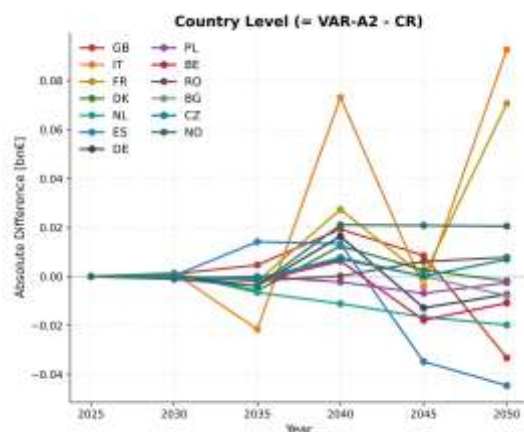


Figure 50 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, EU total [bn€]



Figure 51 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, by country [MtCO2]

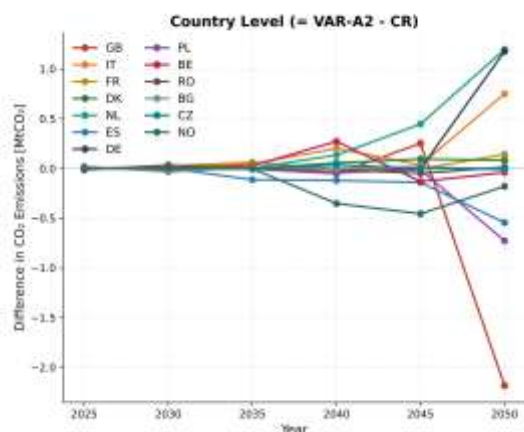


Figure 52 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, EU total [MtCO2]

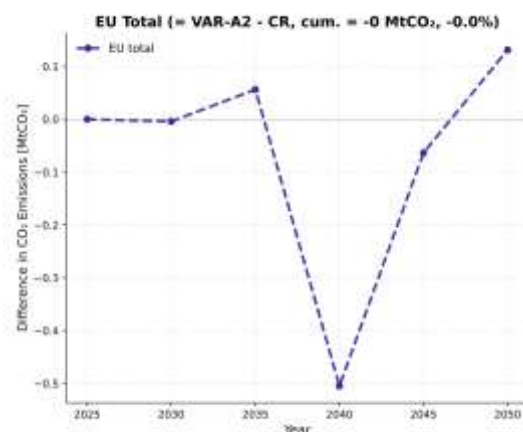


Figure 53 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, by country [€/MWh]

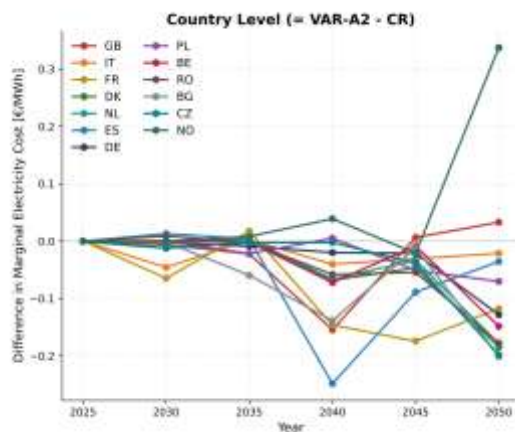


Figure 54 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, EU average [€/MWh]

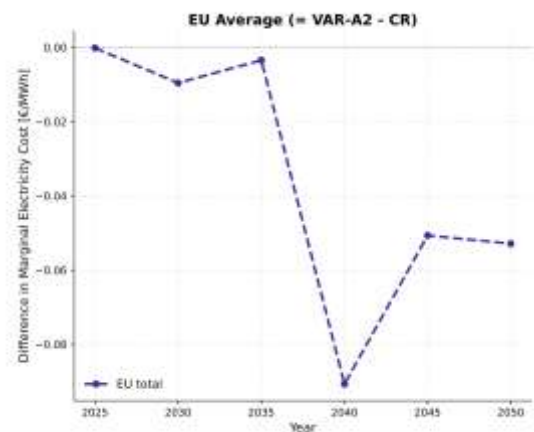


Figure 55 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, by country [TWh]

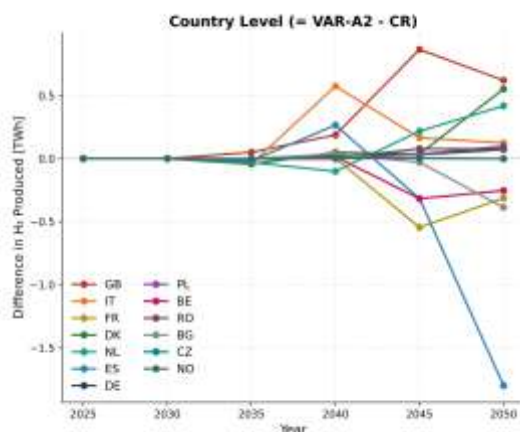


Figure 56 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, EU total [TWh]

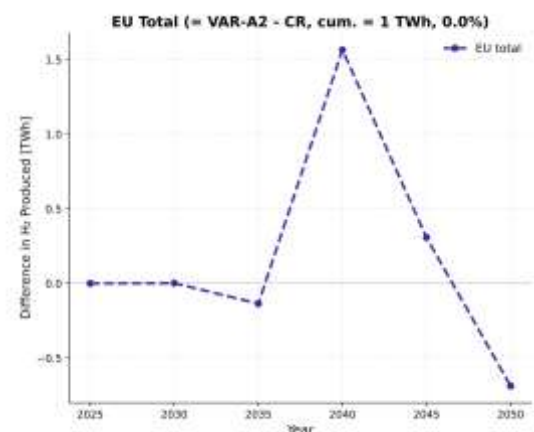


Figure 57 – Absolute difference in levelized cost of grid connected H₂ compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, by country [€/MWh]

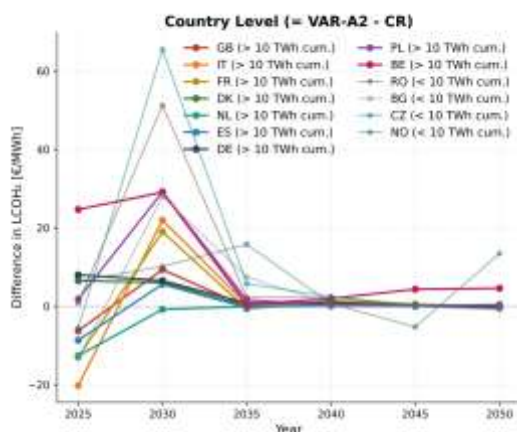
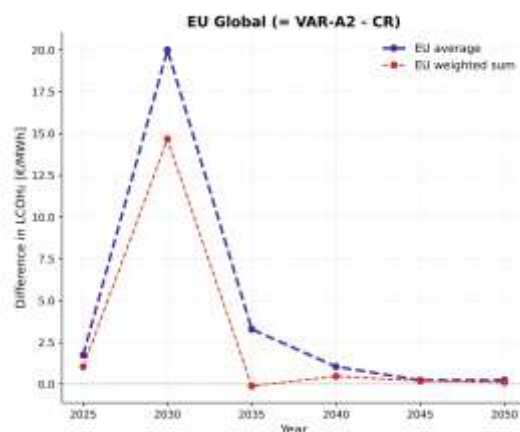


Figure 58 – Absolute difference in levelized cost of grid connected H₂ compared to the Current Regulation for variant Relaxed carbon intensity exemption - VAR-A2, EU average [€/MWh]



2.2.6. Relaxed renewable share exemption (VAR-SUN)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028	From monthly to hourly from 2030	Same bidding zone
VAR-SUN	Relaxed renewable share exemption	From 2028 with renewable share exemption relaxed from 90 to 80 %	From monthly to hourly from 2030, with renewable share exemption relaxed from 90 to 80 %	Same bidding zone

In this variant, additionality and temporal correlation are both waived when the grid renewable share reaches 80% in the previous investment period, instead of 90% in the current regulation. Impacts remain limited: total EU renewable investment moves from +0.05% in 2035 to -0.125% in 2040, and EU emissions by -0.3 Mt in 2035. Grid-connected H₂ production increases in the countries that become exempted and decreases slightly in the others, for a small net increase at EU level (+0.1% in 2040). Electricity prices rise in the countries that expand their production (+0.2% on EU average in 2040), and the average EU LCOH increases as well (+1.5% in 2035, +1% in 2040).

Although still moderate, these effects are more perceptible than for the carbon intensity threshold, because the renewable share criterion waives both additionality and temporal correlation rather than additionality alone. Production increases moderately, but without the additional renewable capacity that would normally accompany it, which pushes electricity prices and hydrogen costs up. Dominant effects occur over 2035-2040, before all producing countries become exempted. As for the carbon intensity criterion, the limited impact reflects the ambition of the scenario, and the 90% threshold remains an important safeguard in a slower decarbonisation context.

Figure 59 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, by country [bn€]

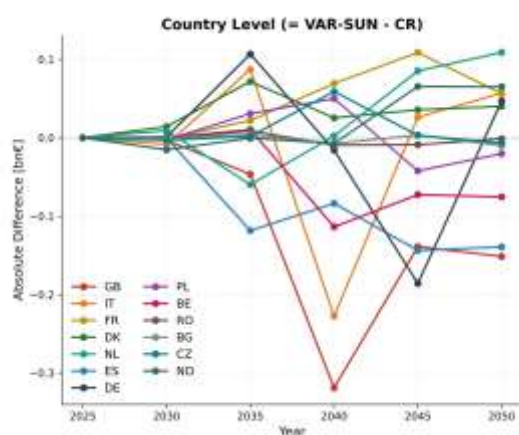


Figure 60 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, EU total [bn€]

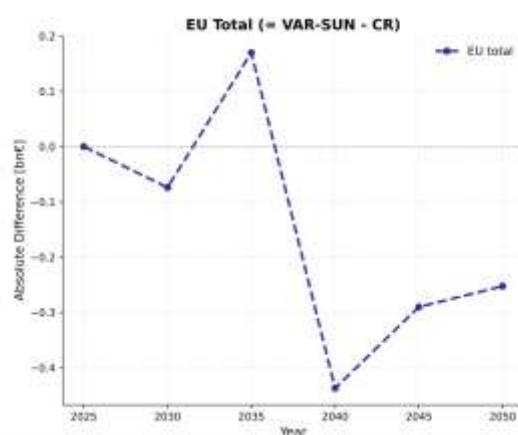


Figure 61 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, by country [MtCO2]

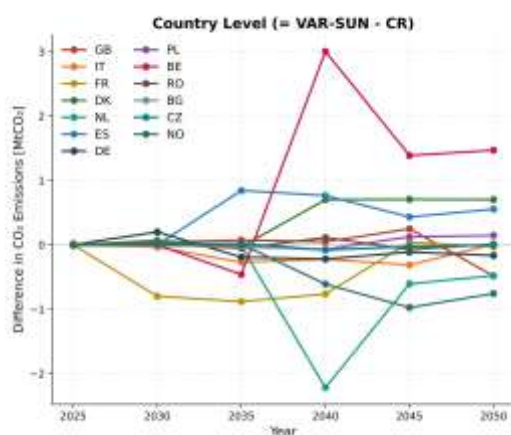


Figure 62 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, EU total [MtCO2]

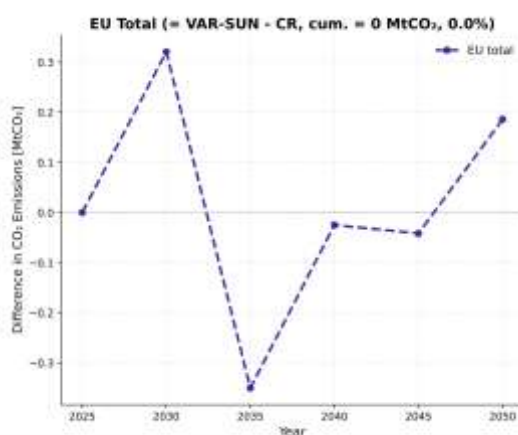


Figure 63 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, by country [€/MWh]

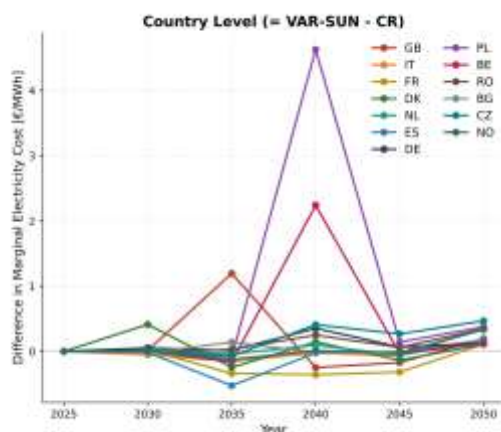


Figure 64 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, EU average [€/MWh]

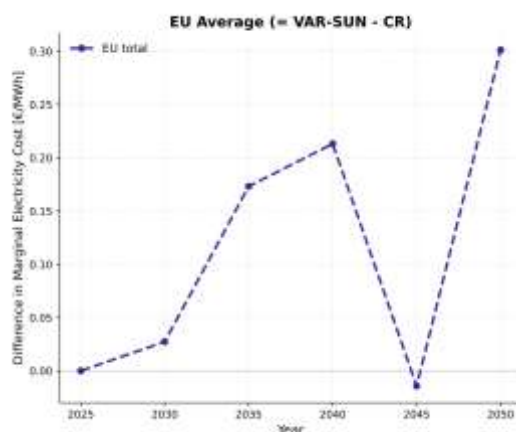


Figure 65 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, by country [TWh]

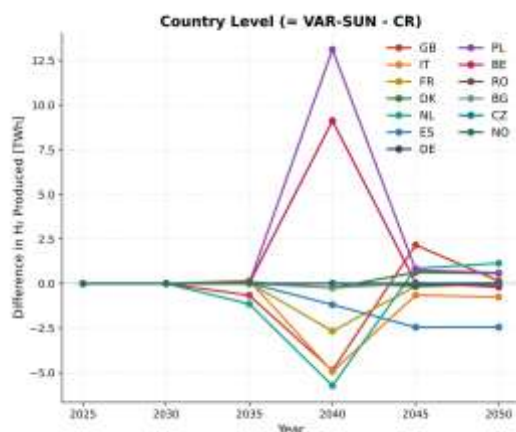


Figure 66 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, EU total [TWh]

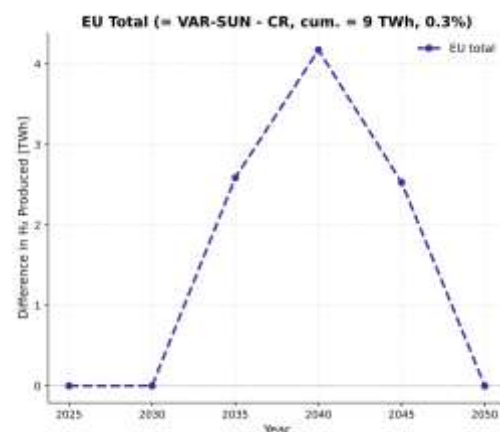


Figure 67 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, by country [€/MWh]

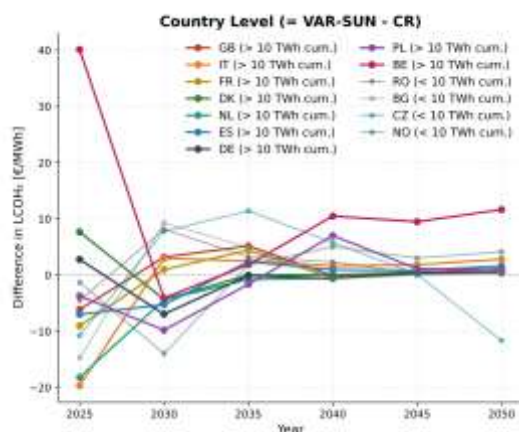
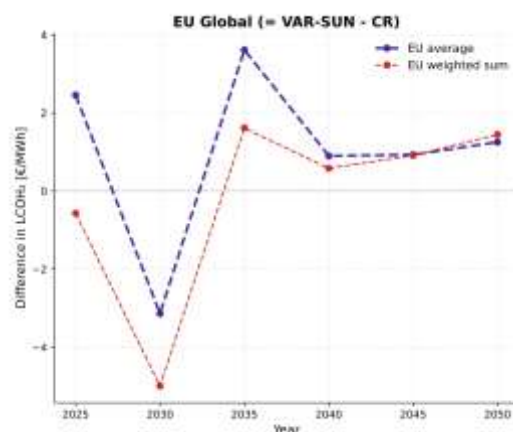


Figure 68 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Relaxed renewable share exemption - VAR-SUN, EU average [€/MWh]



2.2.7. Combined additionality and hourly matching delay with relaxed exemption threshold (VAR-MS)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028 ¹	From monthly to hourly from 2030	Same bidding zone
VAR-MS	Combined additionality and hourly matching delay with relaxed exemption threshold	From 2040, with renewable share exemption relaxed from 90 to 80 %	From monthly to hourly from 2040, with renewable share exemption relaxed from 90 to 80 %	Same bidding zone

This variant combines the three relaxations put forward by five Member States in their joint letter to the European Commission: additionality enforced from 2040 instead of 2028, hourly matching postponed to 2040, and the exemption threshold for both requirements lowered from 90% to 80% renewable share. Investment in renewables decreases by 1.75% in 2030 and 1.4% in 2035, an effect that dampens but persists up to 2040. Emissions increase by 0.8% in 2030 and 0.2% in 2035 (+0.2% overall), and mean EU marginal electricity prices rise by 1 to 2% over the same years, again persisting up to 2040. In 2035, production shifts towards previously non-exempted grids with high capacity factors (Great Britain, Italy; +40% EU production); additional countries reach the lowered exemption threshold in 2035, which becomes visible in 2040 (Poland, Belgium; +2% EU production). LCOH effects are heavily grid-dependent: +3% in Great Britain, where higher electricity prices dominate, against -5% in Italy, where capacity factors improve. The EU weighted average LCOH decreases by 5% in 2035, then stabilises.

This proposal accumulates the effects of the two delays — slower renewable build-out, higher electricity prices and higher emissions. Compared with the variants that only delay a requirement, the lower exemption threshold extends these effects up to 2040, as additional countries then qualify for exemption. Improved capacity factors do increase H₂ production in specific grids, but the cost effects are mostly adverse precisely in the countries where production expands, since electricity prices rise there.

Methodological note – How the model represents the relaxation proposed by five of the Member States in their joint letter to the Commission

The policy variant modelled to capture the proposed relaxations extends the additionality transitional phase to 2035, with existing grandfathering rules maintained for ten years (until 2040 at the latest). In our baseline, no renewable H₂ is produced before 2035: a relaxation expiring in 2035 would therefore be inoperative by construction, and modelling it literally would understate - not test - the proposal. Moreover, under the proposed grandfathering, any electrolyser commissioned before 2035 would remain exempt from additionality until 2040. For the fleet that actually materialises in our scenarios, the proposal is thus functionally equivalent to an additionality requirement starting in 2040 - which is precisely how we implement it.

The same logic applies to temporal correlation: the proposed delay of hourly matching to 2035 would barely bind given the H₂ uptake timeline, so we extend it to 2040 to let the relaxation deploy its full effect.

The implementation is therefore a faithful reading of the proposal: it grants the relaxations their maximum possible impact on the modelled H₂ fleet. The effects we report, whether beneficial or harmful, should accordingly be read as an upper bound of what the relaxations proposed by the five Member States could deliver.

Figure 69 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, by country [bn€]

Figure 70 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, EU total [bn€]

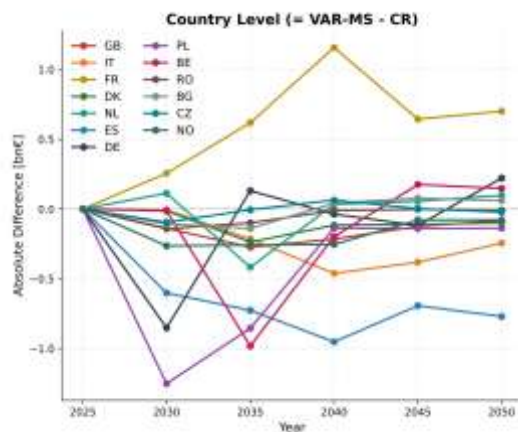


Figure 71 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, by country [MtCO2]



Figure 72 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, EU total [MtCO2]

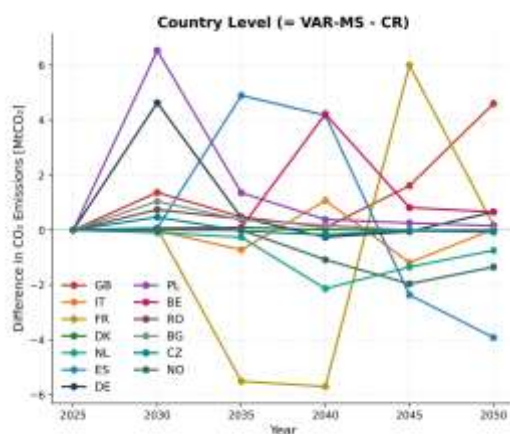


Figure 73 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, by country [€/MWh]

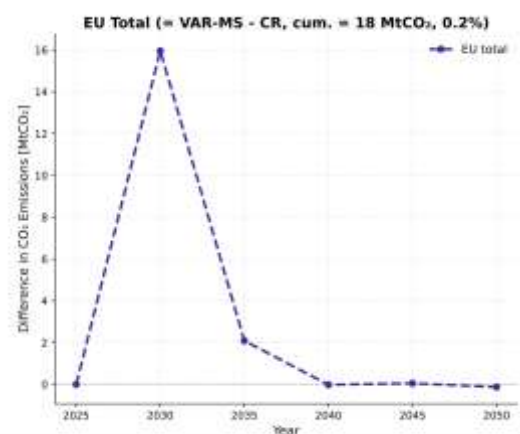


Figure 74 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, EU average [€/MWh]

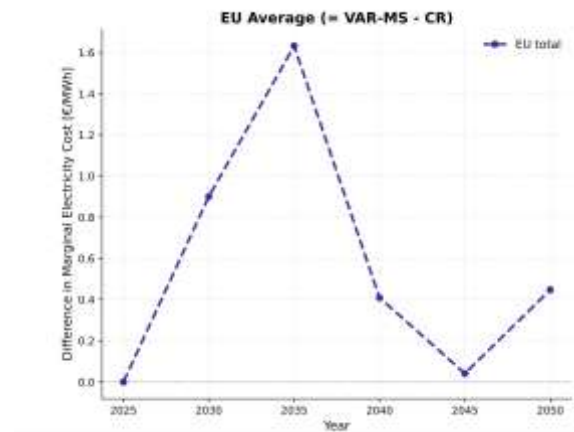
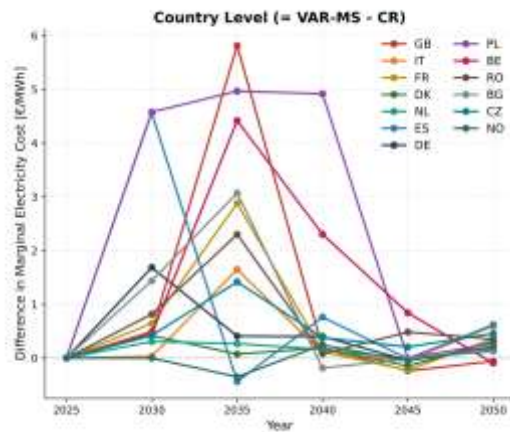


Figure 75 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, by country [TWh]

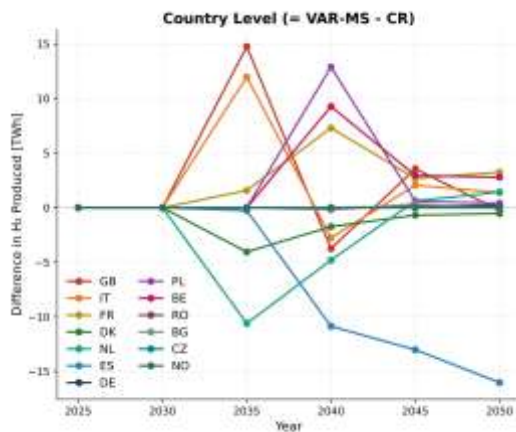


Figure 76 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, EU total [TWh]

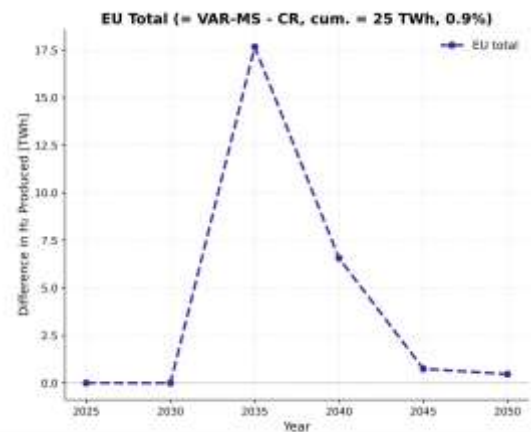


Figure 77 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, by country [€/MWh]

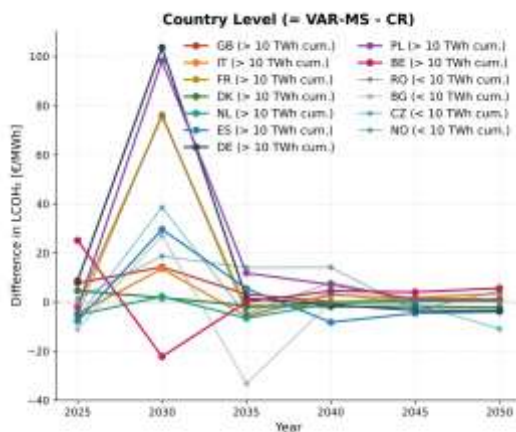
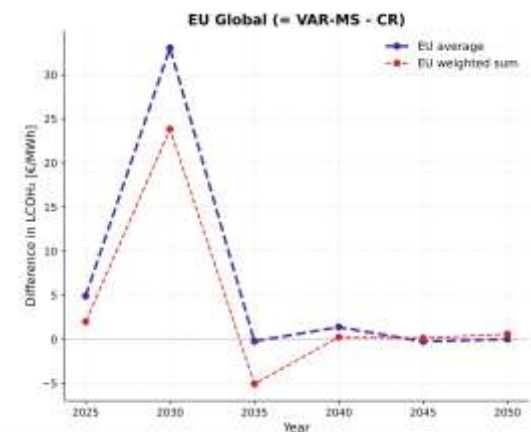


Figure 78 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Additionality and hourly matching delay with relaxed exemption threshold - VAR-MS, EU average [€/MWh]



2.2.8. Interconnected zones (INT)

Reference	Variant	Additionality	Temporal correlation	Geographic correlation
CR	Current Regulation	From 2028 ¹	From monthly to hourly from 2030	Same bidding zone
INT	Interconnected zones	From 2028 ¹	From monthly to hourly from 2030	Directly connected countries, at all times ²

In this variant, renewable electricity used for RFNBO production in a given country can be sourced from any country directly connected to it, whether by AC or DC interconnection. Investment in renewables decreases over 2030-2040 (down to -1% in 2035) and increases again in 2050 to compensate for the missing capacity, for a small net effect over the horizon (-0.1%): the main consequence is a delay in investment rather than a reduction. Emissions increase slightly in 2030 and 2035 (+17 MtCO₂e and +20 MtCO₂e, about +30 MtCO₂e overall). Electricity prices follow the same profile, rising during 2030-2040 (up to +7% in Great Britain, +1.5% on EU average) before falling back in 2050 (-2% on EU average) as the delayed investment materialises. Production redistributes across connected grids and total EU production increases by 40% in 2035, while the EU LCOH drops by about 5% that same year, mainly because intermittency is smoothed across connected zones and capacity factors improve. This effect dampens quickly, with only minor differences from 2040 onwards.

Allowing electrolyzers to source renewable electricity from connected grids has the same qualitative signature as the other relaxations — reduced renewable investment, higher emissions and higher electricity prices — with a partial compensation towards 2050 that remains uncertain: postponing renewable investment puts the transition at risk. The counterpart is a genuine short-term gain in hydrogen production volumes and costs. Unlike most other variants, effects are spread over the whole period.

Figure 79 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Interconnected zones - INT, by country [bn€]

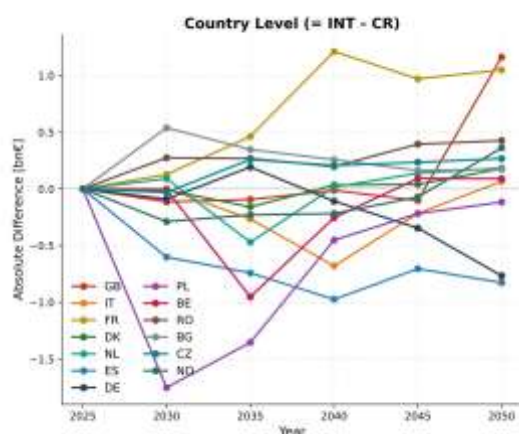


Figure 80 – Absolute difference in renewable investment costs compared to the Current Regulation for variant Interconnected zones - INT, EU total [bn€]

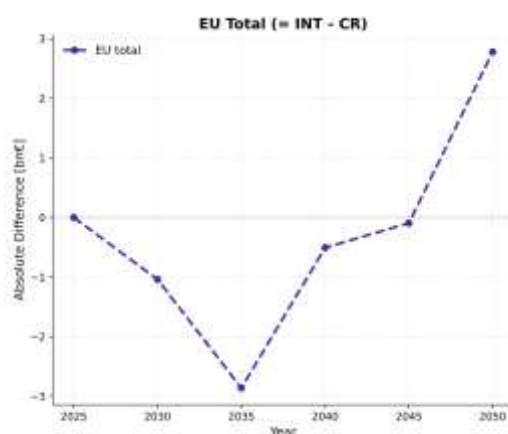


Figure 81 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Interconnected zones - INT, by country [MtCO2]

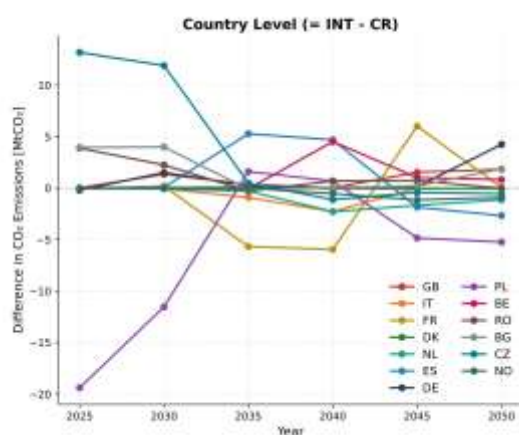


Figure 82 – Absolute difference in CO2 emissions compared to the Current Regulation for variant Interconnected zones - INT, EU total [MtCO2]

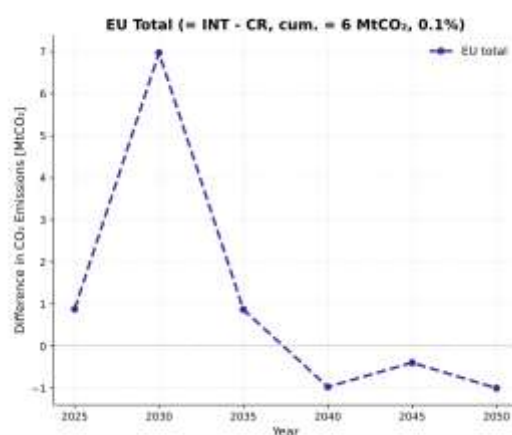


Figure 83 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Interconnected zones - INT, by country [€/MWh]

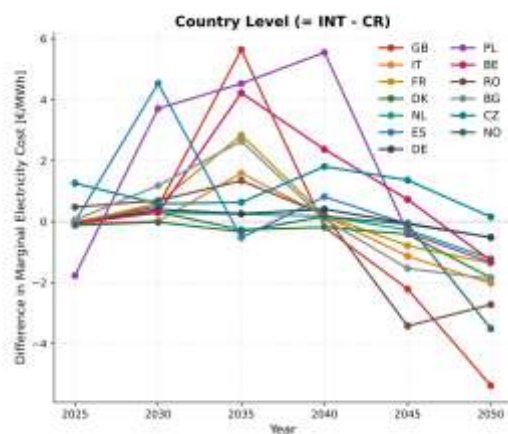


Figure 84 – Absolute difference in marginal electricity costs compared to the Current Regulation for variant Interconnected zones - INT, EU average [€/MWh]

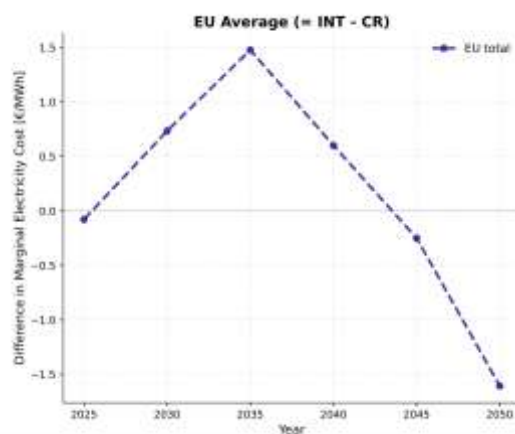


Figure 85 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Interconnected zones - INT, by country [TWh]

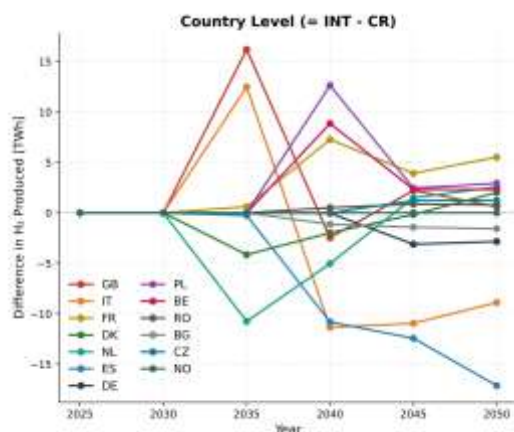


Figure 86 – Absolute difference in grid connected H2 production compared to the Current Regulation for variant Interconnected zones - INT, EU total [TWh]

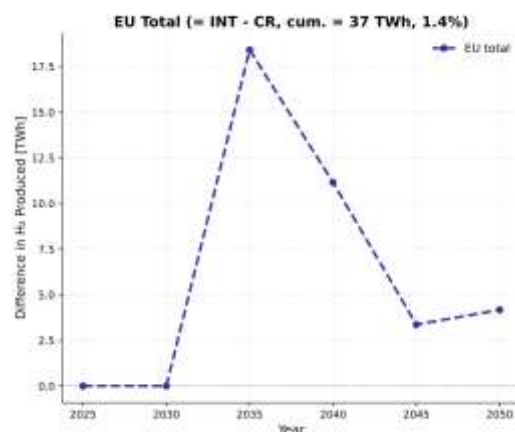


Figure 87 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Interconnected zones - INT, by country [€/MWh]

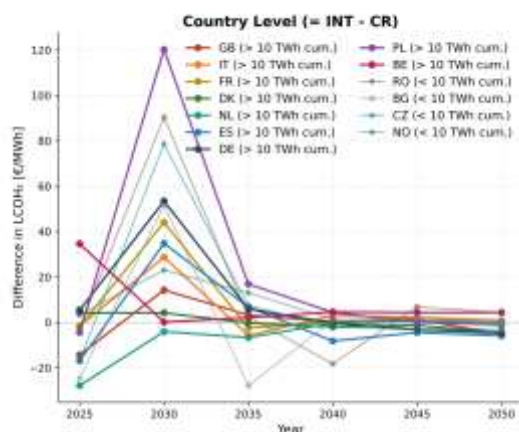
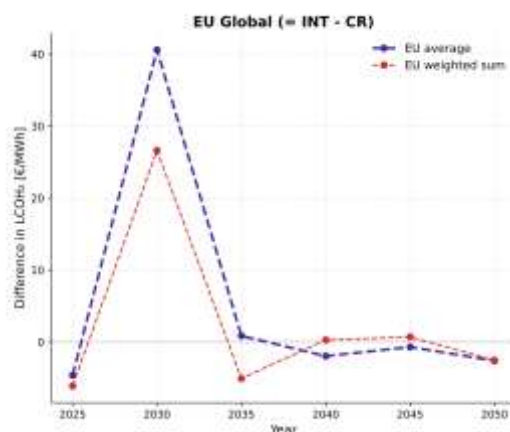


Figure 88 – Absolute difference in levelized cost of grid connected H2 compared to the Current Regulation for variant Interconnected zones - INT, EU average [€/MWh]



2.3. Cross-cutting analysis of policy variants

The previous section examined each variant on its own. This section compares them directly, grouped by the type of relaxation they involve, using the same five indicators throughout.

2.3.1. Impact of delaying additionality or hourly matching requirements

The three delay variants move renewable investment in the same direction: down, by 1.5 to 3.5 bn€ per year around 2030-2035, with delayed additionality the most pronounced. Emissions and electricity prices follow, peaking respectively in 2030 (+6 to +11 MtCO₂e) and 2035 (up to 1.8% or +1.8 €/MWh). Additionality is the stronger of the two safeguards: it is what prevents hydrogen production from cannibalising existing renewable output and slowing decarbonisation. The effects concentrate on 2030 and 2035 and largely disappear afterwards, since most countries become exempted from 2040 and the variants converge towards the current regulation. Under delayed additionality the system does invest back in renewables towards 2050, when capital costs are lower — but this compensation comes late, and in the part of the horizon where the model is least reliable.

On the hydrogen side, none of the variants brings production forward, which points to constraints lying outside the delegated act. In 2035, production increases by 0.4 to 0.5 Mtons and the EU weighted-average LCOH falls by 0.10 to 0.25 €/kg, delaying hourly matching being more effective than delaying additionality, because it directly improves electrolyser capacity factors. Both effects fade from 2040.

Figure 89 - Difference in total EU renewable investments, compared to the current regulation [bn€]

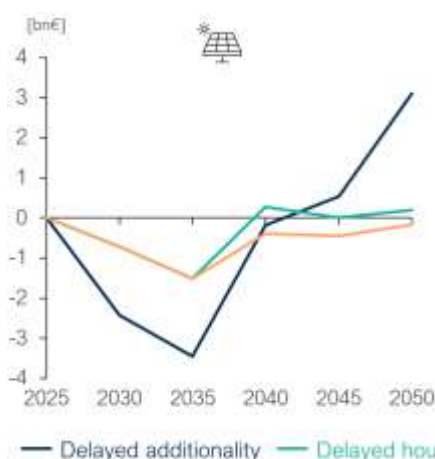


Figure 90 - Difference in total EU CO₂ emissions compared to the current regulation [MtCO₂e]

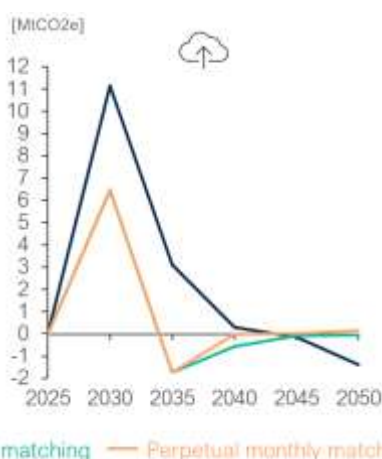


Figure 91 - Difference in average EU electricity marginal price compared to the current regulation [€/MWh]

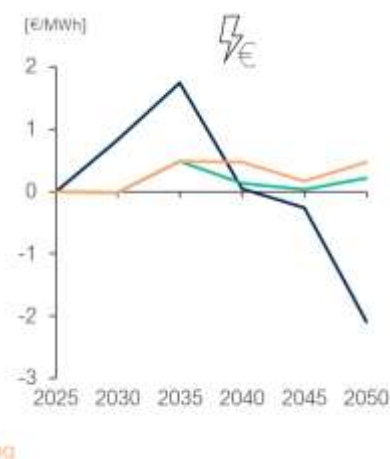


Figure 92 - Difference in total EU RFNBO H2 production compared to the current regulation [Mtons]

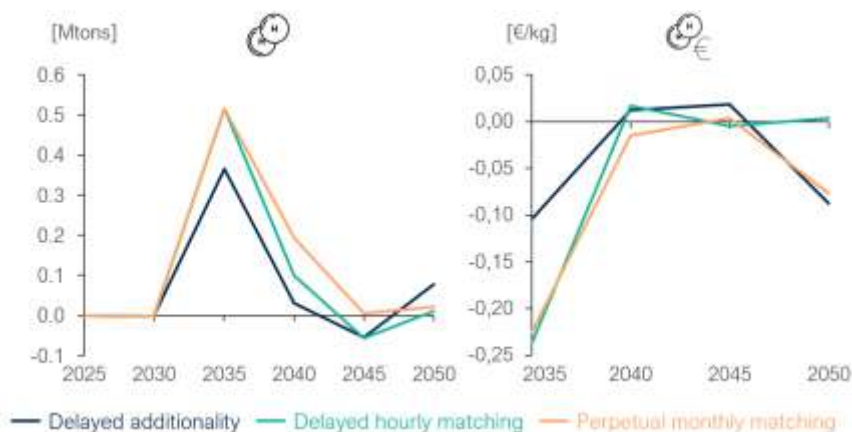
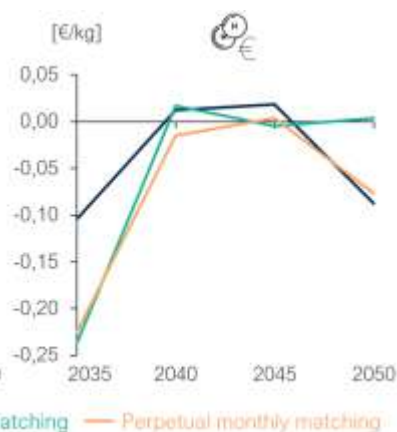


Figure 93 - Difference in EU weighted average LCOH compared to the current regulation [€/kg]



2.3.2. Impact of relaxing exemption thresholds

Compared with the delays, relaxing the exemption thresholds has less pronounced impact. On renewable investment, emissions and electricity prices, the two exemption variants stay within a fraction of the current regulation over the whole horizon, where the delay variants — shown in grey for reference — move by several bn€ and several MtCO₂e. The reason is timing: in a net-zero trajectory, most grids have already crossed the 18 gCO₂eq/MJ and 90% renewable share thresholds by the time renewable hydrogen production becomes significant, so lowering the bar changes little.

Figure 94 - Difference in total EU renewable investments, compared to the current regulation [bn€]

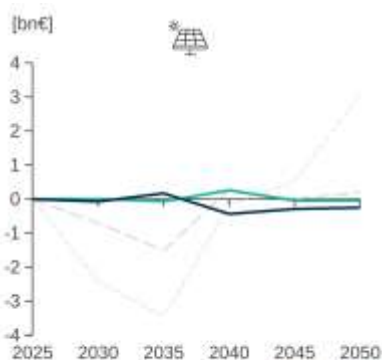


Figure 95 - Difference in total EU CO2 emissions compared to the current regulation [MtCO₂e]

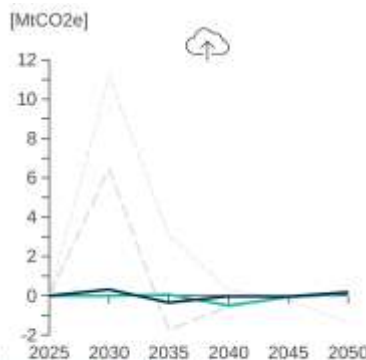
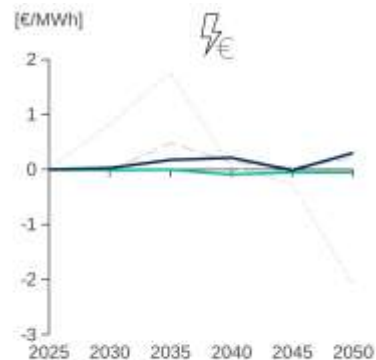


Figure 96 - Difference in average EU electricity marginal price compared to the current regulation [€/MWh]



— Relaxed renewable share exemption — Delayed hourly matching
— Relaxed carbon intensity exemption — Delayed additionality

The same holds for hydrogen. Production increases marginally — around 0.1 Mtons at EU level— and the EU weighted-average LCOH moves by less than 0.05 €/kg, in both directions. The relaxed renewable share exemption has slightly more effect than the carbon intensity one, since it waives both additionality and temporal correlation rather than additionality alone. The current thresholds therefore appear well tailored, provided countries keep developing renewables along a net-zero pathway; under slower decarbonisation they would bind for longer and altering their exact level would have more impact.

Figure 97 - Difference in total EU RFNBO H2 production compared to the current regulation [Mtons]

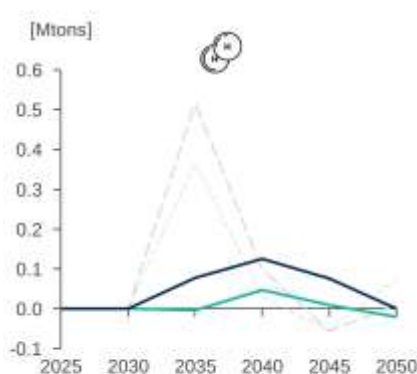
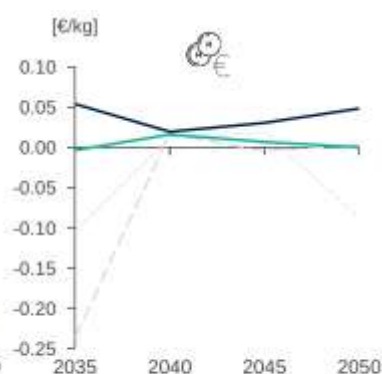


Figure 98 - Difference in EU weighted average LCOH compared to the current regulation [€/kg]



2.3.3. Impact of combining delay in requirements and relaxed exemption thresholds

This variant combines the two delays with a lower exemption threshold, and it accumulates their effects: it has the worst systemic profile of all variants. Renewable investment falls by close to 4 bn€ in 2035, emissions peak at +16 MtCO_{2e} in 2030 — half again as much as delayed additionality alone — and average EU electricity prices rise by around 1.6 €/MWh in 2035. The magnitude of the effect mainly comes from the combined effect of relaxing additionality and temporality requirements. Unlike the single-relaxation variants, the divergence does not fully dissipate after 2040: the lower threshold brings additional countries into exemption, extending the effect in time.

Hydrogen production in 2035 increases by about 0.53 Mtons — the same order of magnitude as delaying additionality or hourly matching on their own — and the EU weighted-average LCOH falls by 0.17 €/kg before returning to, and slightly above, the current regulation from 2040. Combining the relaxations therefore multiplies the systemic cost without multiplying the benefit, which follows directly from the synergy between additionality and temporal correlation: relaxing one already weakens the other, so relaxing both adds limited to no benefits.

Figure 99 - Difference in total EU renewable investments, compared to the current regulation [bn€]

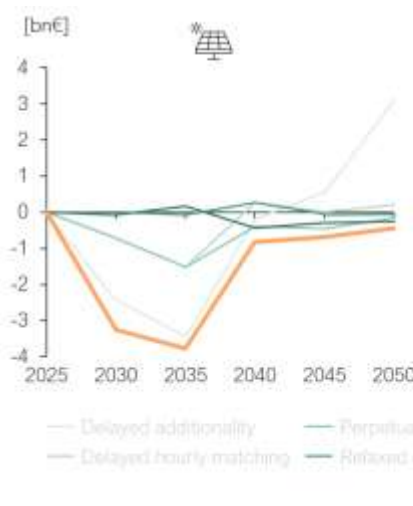


Figure 100 - Difference in total EU CO2 emissions compared to the current regulation [MtCO2e]

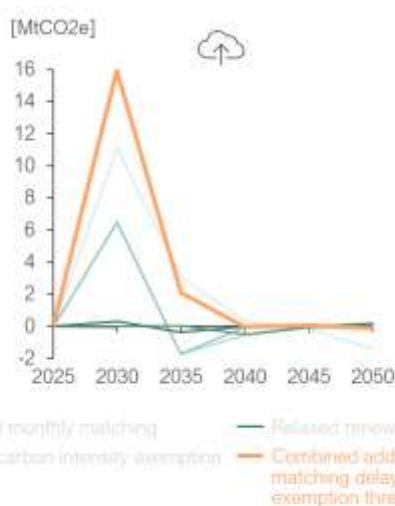


Figure 101 - Difference in average EU electricity marginal price compared to the current regulation [€/MWh]

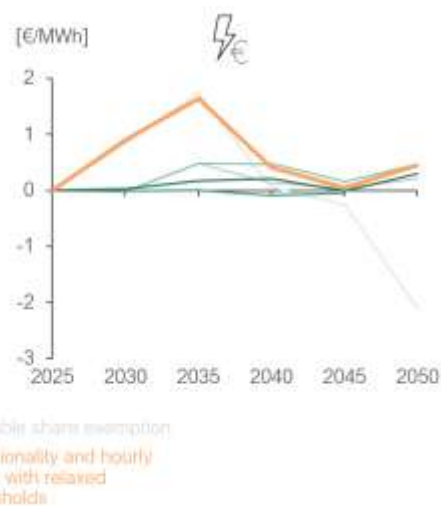


Figure 102 - Difference in total EU RFNBO H2 production compared to the current regulation [Mtons]

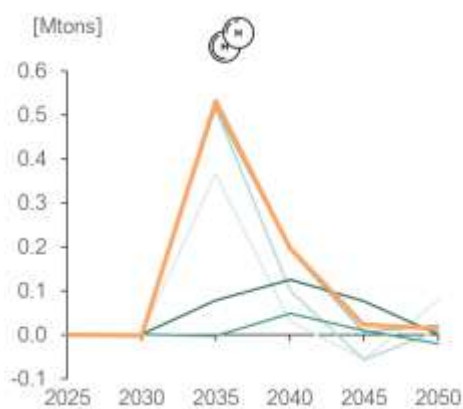
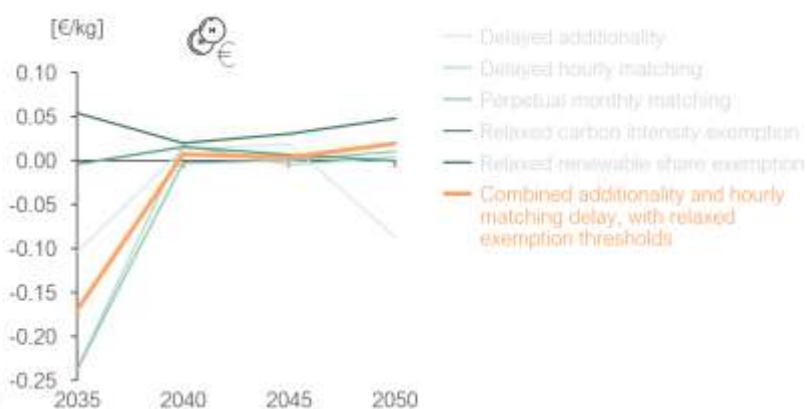


Figure 103 - Difference in EU weighted average LCOH compared to the current regulation [€/kg]



2.3.4. Impact of relaxing geographical requirements

Allowing electrolyzers to source renewable electricity from directly interconnected zones behaves like the other relaxations in the short term: renewable investment falls (down to -2.9 bn€ in 2035), emissions increase (+7 MtCO₂e in 2030) and electricity prices rise (+1.5 €/MWh in 2035). What differs is what comes afterwards. From 2045 the system invests back, ending 2.7 bn€ above the current regulation in 2050, and electricity prices fall below it. The variant delays renewable investment rather than reducing it.

On hydrogen it is the most favourable variant in the short term — production increases by about 0.55 Mtons in 2035, the largest gain of all variants, and the LCOH falls by 0.17 €/kg — because pooling connected grids smooths intermittency and improves capacity factors. Here too, nothing moves before 2035. The long-term compensation is real in the model but should be treated with caution: it materialises in the part of the horizon where assumptions on costs, demand and imports are least reliable, and delaying renewable investment in the meantime is a risk taken on the transition itself.

Figure 104 - Difference in total EU renewable investments, compared to the current regulation [bn€]

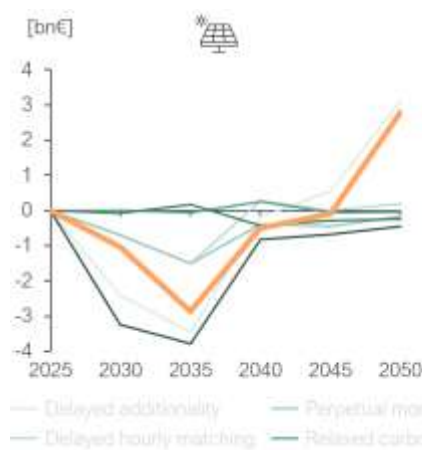


Figure 105 - Difference in total EU CO₂ emissions compared to the current regulation [MtCO₂e]

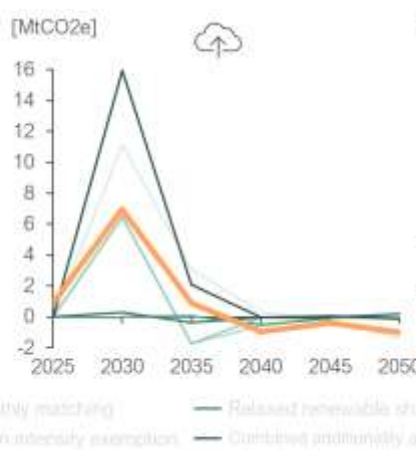


Figure 106 - Difference in average EU electricity marginal price compared to the current regulation [€/MWh]

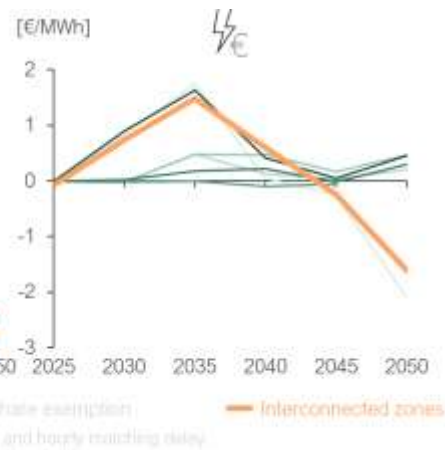


Figure 107 - Difference in total EU RFNBO H2 production compared to the current regulation [Mtons]

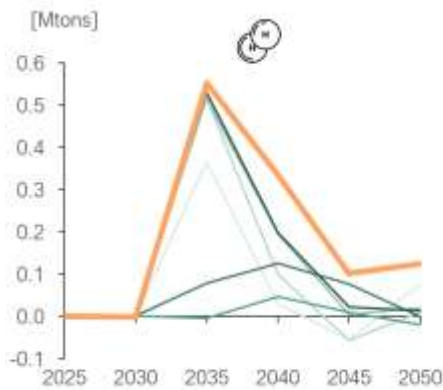
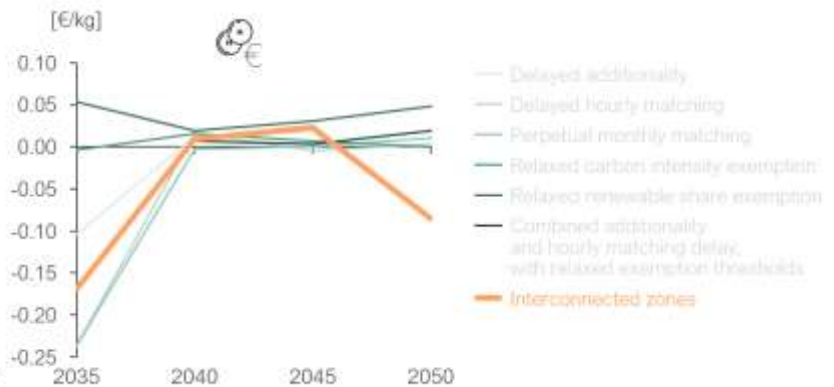


Figure 108 - Difference in EU weighted average LCOH compared to the current regulation [€/kg]



2.3.5. Variants comparison

The different variants can be assessed across the trade-off between their detrimental impact on the energy transition, and their positive impact on the renewable hydrogen production. The figure characterises these two dimensions using the change in hydrogen production against the change in renewable investment. In 2035, three variants stand out as detrimental for the energy system: the combined additionality and hourly matching delay with relaxed exemption threshold, delayed additionality and interconnected zones, each costing more than 1% of total renewable investment for a production gain of roughly half a Mton. Delaying or removing hourly matching sits in between, with a smaller systemic penalty for a comparable gain. The two exemption relaxations sit essentially on top of the current regulation, on both axes.

Figure 109 - Trade-off between the difference in total renewable investments [bn€] and the difference in total EU RFNBO H2 production [Mtons] compared to the current regulation, in 2035

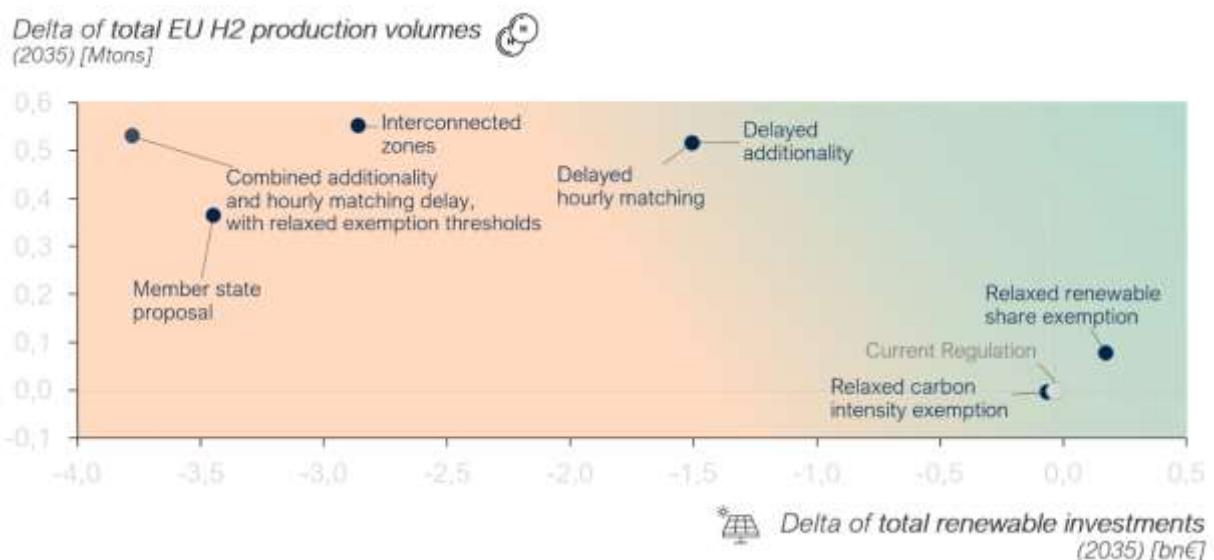
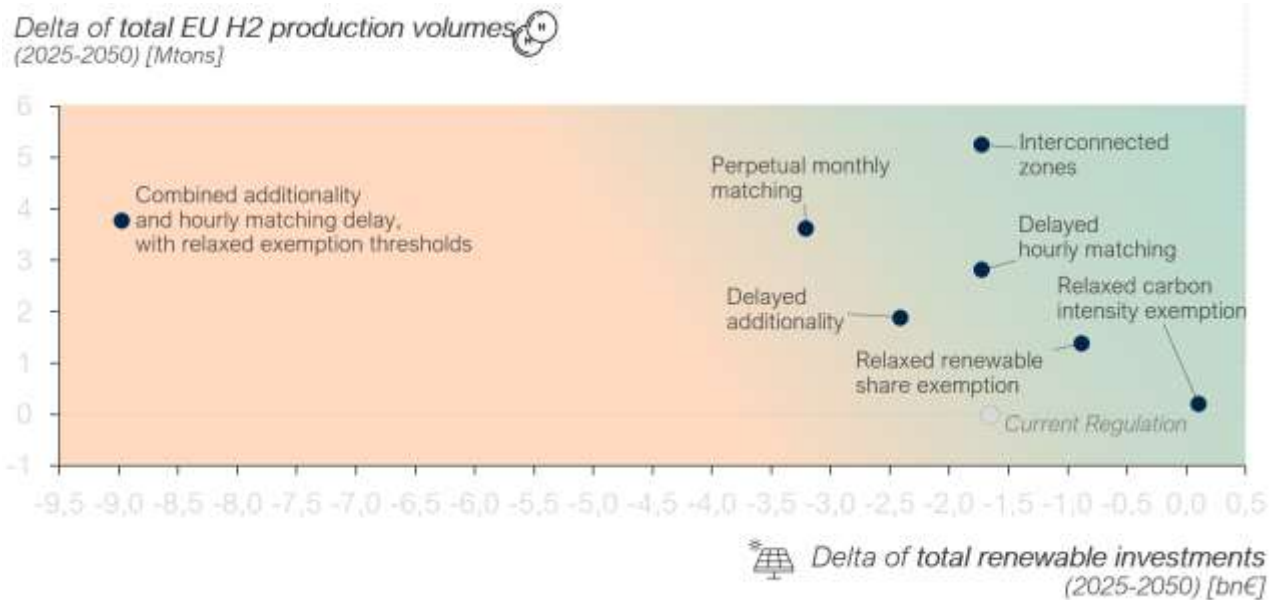


Figure 110 - Trade-off between the difference in total renewable investments [bn€] and the difference in total EU RFNBO H2 production [Mtons] compared to the current regulation, over the whole period (2025-2050)



Over the whole 2025-2050 period, the picture softens: most variants converge back towards the current regulation on investment, and only the combined additionality and hourly matching delay remains clearly detrimental for the energy transition. However, effects taking place in the 2045-2050 window are uncertain, and correspond to a period where model outputs are least robust. Slowing down renewable deployment in the short term poses high risks for the decarbonization objectives of Europe.

3. Policy recommendations & conclusion

Three recommendations can be derived from the results of this study.

Preserve the additionality, temporal and geographic correlation requirements. The model shows that these requirements secure the additional renewable capacity that hydrogen production needs, and prevent electrolyzers from cannibalising existing renewable output. Relaxing them delivers temporary gains on hydrogen costs and volumes — below 0.25 €/kg, concentrated in 2035 — while reducing renewable investment, raising emissions and pushing electricity prices up for the rest of the system. The requirements also work as a pair: relaxing or delaying one weakens the other, which is why the combined delay of additionality and hourly matching, as proposed by five of the Member States in their joint letter to the European Commission, produces the worst systemic outcome of all the variants tested.

Preserve the exemption thresholds at their current level. At 18 gCO₂eq/MJ and 90% renewable share they are adequately sized, provided countries respect their decarbonization targets and consequently scale renewable production: in a net-zero trajectory, relaxing the exemption thresholds has few effects, since most grids cross them before hydrogen production scales. Removing them, on the other hand, could be counterproductive — it penalises PV-dominated grids that cannot economically meet a permanent hourly matching requirement, reduces EU hydrogen production and oversizes the system. The pertinence of the thresholds lies in the case this study does not model: a decarbonisation slower than assumed here, in which the thresholds would hold a more important protective role against cannibalization.

Act on what actually constrains renewable hydrogen. Production does not scale up meaningfully in any of the variants before the 2030-2035 period, because renewable hydrogen remains more expensive than imports and steam methane reforming until the carbon price closes the gap. The binding constraint is the economics of the alternatives, not the RFNBO criteria. A strong ETS, together with policies that accelerate renewable deployment, could support renewable hydrogen production while supporting rather than slowing down the energy transition.

These conclusions come from a single cost-optimisation model, and effects should be read as directions and orders of magnitude rather than as forecasts. Within those limits, the message is consistent across indicators and across variants: the three pillars are relevant to preserve renewable investment and associated energy transition, and the case for weakening them is not supported by the modelled outcomes.

Appendix

Table 4 - Hypotheses of the baseline scenario

Process / driver	Molecule	Type	Parameter (unit)	2025	2030	2035	2040	2045	2050	Source / note
A. INDUSTRY										
Steel — primary route	Hydrogen	Exogenous	Share of primary (ore-based) route in total steel output	74%	71%	67%	64%	58%	57%	Agora Industry [5]
Steel — H ₂ -DRI	Hydrogen	Exogenous	Share of H ₂ -based direct reduction within the primary route	0%	6%	20%	39%	55%	55%	Agora Industry [5]. Plateau at 55% from 2045
Ammonia synthesis	Hydrogen → NH ₃	Exogenous	Share of NH ₃ produced by Haber-Bosch from renewable H ₂	100%	100%	100%	100%	100%	100%	PyPSA-EUR default configuration
Methanol synthesis	Hydrogen → e-methanol	Exogenous	Share of MeOH produced by methanolisation from H ₂	100%	100%	100%	100%	100%	100%	PyPSA-EUR default configuration
HVC feedstock (naphtha)	Fischer-Tropsch liquids	<i>Endogenous</i>	Share of synthetic vs. fossil naphtha in primary HVC	—	—	—	—	—	—	Optimised by the model. Both routes feed the same oil bus; the mix responds to the CO ₂ constraint
HVC production routes	Fischer-Tropsch liquids	Exogenous	Share of primary (virgin) production	85%	78%	70%	60%	50%	40%	PyPSA-EUR default configuration
HVC production routes	—	Exogenous	Share of mechanical recycling	15%	18%	21%	24%	27%	30%	PyPSA-EUR default configuration
HVC production routes	—	Exogenous	Share of chemical recycling	0%	4%	8%	12%	16%	20%	PyPSA-EUR default configuration
Industrial methane use	e-methane (Sabatier)	<i>Endogenous</i>	Share of synthetic CH ₄ vs. fossil gas and biomethane	—	—	—	—	—	—	Optimised by the model; methanation enabled
B. TRANSPORT										
Land transport — fuel cell	Hydrogen	Exogenous	Share of H ₂ fuel-cell vehicles in land transport activity	0%	0%	0%	0%	0%	0%	Full electrification scenario
Land transport — battery electric	— (electricity)	Exogenous	Share of battery-electric vehicles	5%	20%	45%	70%	85%	100%	Full electrification scenario
Land transport — ICE	Fischer-Tropsch liquids / fossil oil	Exogenous	Share of internal-combustion vehicles	95%	80%	55%	30%	15%	0%	Full electrification scenario. Renewable share of the liquid fuel burned is endogenous

Process / driver	Molecule	Type	Parameter (unit)	2025	2030	2035	2040	2045	2050	Source / note
Shipping — fuel cell	Hydrogen	Exogenous	Share of H ₂ in shipping final energy	1.5%	4.0%	7.0%	11.0%	15.0%	19.0%	IEA 2023 Net Zero Roadmap [4] – Shipping
Shipping methanol —	e-methanol	Exogenous	Share of methanol in shipping final energy	2.6%	7.0%	16.0%	26.3%	36.7%	47.0%	IEA 2023 Net Zero Roadmap [4] – Shipping, with the ammonia share reallocated to methanol
Shipping ammonia —	Ammonia	—	Share of NH ₃ in shipping final energy	0%	0%	0%	0%	0%	0%	NH ₃ bunkering not represented in PyPSA-Eur; IEA NZE share [4] (~44% by 2050) reassigned to methanol
Shipping — ICE	Fischer-Tropsch liquids / fossil oil	Exogenous	Share of oil products in shipping final energy	95.9%	89.0%	77.0%	62.7%	48.3%	34.0%	IEA 2023 Net Zero Roadmap [4] (fossil oil and biofuels combined)
Aviation	Fischer-Tropsch liquids	Endogenous	Share of synthetic kerosene in aviation fuel	—	—	—	—	—	—	No exogenous SAF or e-kerosene mandate imposed; optimised by the model
Transport methane —	e-methane	—	Share of CH ₄ in road or maritime transport	0%	0%	0%	0%	0%	0%	No gaseous-fuel share represented for transport in this configuration
Agricultural machinery	— (electricity) / oil	Exogenous	Electric share / oil share	50 / 50	50 / 50	50 / 50	50 / 50	50 / 50	50 / 50	Held constant over the horizon
C. HYDROGEN INPUT REQUIRED PER UNIT OF DERIVED MOLECULE (constant over the horizon unless indicated)										
H ₂ -DRI steelmaking	Hydrogen steel →	Exogenous	MWh H ₂ per t of DRI steel	1.70	1.70	1.70	1.70	1.70	1.70	PyPSA-EUR default configuration (process-specific)
H ₂ -DRI steelmaking	— (electricity)	Exogenous	MWh electricity per t of DRI steel	0.322	0.322	0.322	0.322	0.322	0.322	PyPSA-EUR default configuration (process-specific)
Haber-Bosch	Hydrogen NH ₃ →	Exogenous	MWh H ₂ per t of NH ₃	5.93	5.93	5.93	5.93	5.93	5.93	PyPSA-EUR default configuration (process-specific)
Haber-Bosch	— (electricity)	Exogenous	MWh electricity per t of NH ₃	0.247	0.247	0.247	0.247	0.247	0.247	PyPSA-EUR default configuration (process-specific)
Haber-Bosch	Hydrogen NH ₃ →	Derived	MWh H ₂ per MWh NH ₃ (LHV)	1.15	1.15	1.15	1.15	1.15	1.15	PyPSA-EUR default configuration (process-specific)
Methanolisation	Hydrogen → e-methanol	Exogenous	MWh H ₂ per MWh MeOH	1.138	1.138	1.138	1.138	1.138	1.138	PyPSA-EUR default configuration (process-specific), DECHEMA 2017 [10]
Methanolisation	— (electricity)	Exogenous	MWh electricity per t of MeOH	0.167	0.167	0.167	0.167	0.167	0.167	PyPSA-EUR default configuration (process-specific)
Fischer-Tropsch	Hydrogen synthetic liquids →	Exogenous	MWh H ₂ per MWh liquid hydrocarbon	1.474	1.420	1.391	1.362	1.344	1.326	PyPSA-EUR default configuration (process-specific), Danish Energy Agency 2022 [11]
Methanation (Sabatier)	Hydrogen → e-methane	Exogenous	MWh H ₂ per MWh CH ₄	1.250	1.250	1.250	1.250	1.250	1.250	PyPSA-EUR default configuration (process-specific), Palzer & Schaber [12]
Chlor-alkali	Hydrogen (co-product)	Exogenous	MWh H ₂ produced per t of chlorine	0.937	0.937	0.937	0.937	0.937	0.937	PyPSA-EUR default configuration (process-specific)

Process / driver	Molecule	Type	Parameter (unit)	2025	2030	2035	2040	2045	2050	Source / note
Ammonia cracking	NH ₃ hydrogen →	Exogenous	MWh NH ₃ per MWh H ₂ recovered	1.46	1.46	1.46	1.46	1.46	1.46	PyPSA-EUR default configuration (process-specific)
D. UNDERLYING DEMAND LEVELS (exogenous, held constant at their 2023 level over the whole horizon)										
Steel production	Hydrogen (via DRI)	Exogenous	Mt of crude steel per year	136.5	136.5	136.5	136.5	136.5	136.5	JRC-IDEES / Eurostat energy balances [3], reference year 2023; assumed constant
Ammonia production	Hydrogen NH ₃ →	Exogenous	Mt NH ₃ per year	11.79	11.79	11.79	11.79	11.79	11.79	Nitrogen statistics dataset (USGS Minerals Yearbook 2022) [13]; assumed constant
Methanol production	Hydrogen → e-methanol	Exogenous	Mt MeOH per year (EU total)	1.5	1.5	1.5	1.5	1.5	1.5	DECHEMA 2017 [10], disaggregated to countries using JRC IDEES [3]
HVC production	Fischer-Tropsch liquids	Exogenous	Mt HVC per year (EU total)	52.0	52.0	52.0	52.0	52.0	52.0	DECHEMA 2017 [10], disaggregated to countries using JRC IDEES [3]
Chlorine production	Hydrogen (co-product)	Exogenous	Mt Cl per year (EU total)	9.58	9.58	9.58	9.58	9.58	9.58	DECHEMA 2017 [10], disaggregated to countries using JRC IDEES [3]
Basic chemicals excl. NH ₃	Various	Exogenous	Mt per year (EU total)	69.0	69.0	69.0	69.0	69.0	69.0	config_baseline.yaml (basic_chemicals_without_NH3_production_today)
Land transport activity (road)	Hydrogen liquids / electricity	Exogenous	TWh of final energy demand per year	3 585	3 585	3 585	3 585	3 585	3 585	JRC-IDEES / Eurostat energy balances [3], reference year 2023; assumed constant
Rail	— (electricity)	Exogenous	Final energy demand (TWh/yr)	77.6	77.6	77.6	77.6	77.6	77.6	JRC-IDEES / Eurostat energy balances [3], reference year 2023; assumed constant
Shipping activity	Hydrogen / e-methanol liquids	Exogenous	TWh of final energy demand per year	562	562	562	562	562	562	JRC-IDEES / Eurostat energy balances [3], reference year 2023; assumed constant
Aviation activity	Fischer-Tropsch liquids	Exogenous	TWh of final energy demand per year	695	695	695	695	695	695	JRC-IDEES / Eurostat energy balances [3], reference year 2023; assumed constant
E. SUPPLY-SIDE BOUNDARY CONDITIONS AFFECTING RENEWABLE MOLECULE DEMAND										
Extra-European H ₂ imports	Hydrogen	Exogenous	Annual import ceiling (TWh)	0	197	187	220	200	253	Nielsen 2026, low H ₂ demand scenario, high VRES variant [6]
Extra-European H ₂ imports	Hydrogen	Exogenous	Import price (€/MWh)	1 000	75.0	68.5	62.0	58.0	54.0	Hampp 2023 [7]

Table 5 - Techno-economic assumptions for hydrogen production, storage and transport, 2025–2050

Technology (PyPSA carrier)	Parameter	Unit	2025	2030	2035	2040	2045	2050	Source / note
A. HYDROGEN PRODUCTION									
H2 Electrolysis	Investment (CAPEX)	EUR/kW _e	2 263	1 886	1 697	1 509	1 383	1 257	IEA 2023 [14]
H2 Electrolysis	Annualised capital cost	EUR/MW _e /yr	284 700	237 300	213 600	189 800	174 000	158 200	IEA 2023 [14], Danish Energy Agency [11] (annuity at 7 % over 25 yr, plus FOM)
H2 Electrolysis	Fixed O&M	% of CAPEX/yr	4.0	4.0	4.0	4.0	4.0	4.0	Danish Energy Agency [11]
H2 Electrolysis	Efficiency (elec → H ₂)	per unit	0.587	0.622	0.637	0.653	0.676	0.699	Danish Energy Agency [11]
H2 Electrolysis	Waste heat output	per unit	0.264	0.223	0.204	0.185	0.157	0.129	Danish Energy Agency [11]
H2 Electrolysis	Technical lifetime	years	25	25	25	25	25	25	Danish Energy Agency [11]
H2 Electrolysis	Minimum part load	per unit	0	0	0	0	0	0	No minimum load imposed
SMR	Investment (CAPEX)	EUR/kW _{CH₄}	659	659	659	659	659	659	Danish Energy Agency [11]
SMR	Annualised capital cost	EUR/MW _{CH₄} /yr	86 080	86 080	86 080	86 080	86 080	86 080	Danish Energy Agency [11]
SMR	Fixed O&M	% of CAPEX/yr	5.0	5.0	5.0	5.0	5.0	5.0	Danish Energy Agency [11]
SMR	Efficiency (CH ₄ → H ₂)	per unit, LHV	0.76	0.76	0.76	0.76	0.76	0.76	IEA 2020 [15]
SMR	Technical lifetime	years	30	30	30	30	30	30	IEA 2020 [15]
Biomass to H ₂	—	—	n/a	n/a	n/a	n/a	n/a	n/a	Deactivated in this run
Extra-European H ₂ imports	Import price	EUR/MWh	1 000	75.0	68.5	62.0	58.0	54.0	Hampp 2023 [7]
Extra-European H ₂ imports	Annual volume ceiling	TWh/yr	0	197	187	220	200	253	Nielsen 2026, low H2 demand scenario, high VRES variant [6]
B. HYDROGEN RE-ELECTRIFICATION									
H2 Fuel Cell	Investment (CAPEX)	EUR/kW _e	1 603	1 469	1 369	1 269	1 169	1 069	Danish Energy Agency [16]
H2 Fuel Cell	Annualised capital cost	EUR/MW/yr	308 400	282 700	263 400	244 100	224 900	205 600	Danish Energy Agency [16]
H2 Fuel Cell	Fixed O&M	% of CAPEX/yr	5.0	5.0	5.0	5.0	5.0	5.0	Danish Energy Agency [16]
H2 Fuel Cell	Efficiency (H ₂ → elec)	per unit	0.50	0.50	0.50	0.50	0.50	0.50	Danish Energy Agency [16]
H2 Fuel Cell	Technical lifetime	years	10	10	10	10	10	10	Danish Energy Agency [16]
H2 turbine	Investment (CAPEX)	EUR/kW _e	594	581	574	566	558	550	Danish Energy Agency [16], OCGT costs used as proxy
H2 turbine	Annualised capital cost	EUR/MW/yr	61 520	60 240	59 460	58 680	57 900	57 120	Danish Energy Agency [16], OCGT costs used as proxy

Technology (PyPSA carrier)	Parameter	Unit	2025	2030	2035	2040	2045	2050	Source / note
H2 turbine	Fixed O&M	% of CAPEX/yr	1.78	1.78	1.79	1.79	1.80	1.80	Danish Energy Agency [16], OCGT costs used as proxy
H2 turbine	Variable O&M	EUR/MWh	6.01	6.01	6.01	6.01	6.01	6.01	Danish Energy Agency [16], OCGT costs used as proxy
H2 turbine	Efficiency (H ₂ → elec)	per unit	0.405	0.410	0.415	0.420	0.425	0.430	Danish Energy Agency [16], OCGT costs used as proxy
H2 turbine	Technical lifetime	years	25	25	25	25	25	25	Danish Energy Agency [16], OCGT costs used as proxy
C. HYDROGEN STORAGE — COSTS AND PERFORMANCE									
H2 Store underground —	Investment (CAPEX)	EUR/kWh	3.34	2.67	2.34	2.01	1.81	1.60	Danish Energy Agency [17], including storage
H2 Store underground —	Annualised capital cost	EUR/MWh/yr	234	187	164	141	127	112	Danish Energy Agency [17] (annuity at 7 % over 100 yr)
H2 Store underground —	Fixed and variable O&M	% / EUR/MWh	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0	No O&M assigned in the database
H2 Store underground —	Technical lifetime	years	100	100	100	100	100	100	Danish Energy Agency [17]
H2 Store — steel tank	Investment (CAPEX)	EUR/kWh	68.1	60.0	48.1	36.2	32.1	28.1	Danish Energy Agency [17], including storage
H2 Store — steel tank	Annualised capital cost	EUR/MWh/yr	6 383	5 507	4 545	3 583	3 190	2 798	Danish Energy Agency [17]
H2 Store — steel tank	Fixed O&M	% of CAPEX/yr	1.08	1.11	1.39	1.85	1.87	1.90	Danish Energy Agency [17]
H2 Store — steel tank	Technical lifetime	years	27.5	30	30	30	30	30	Danish Energy Agency [17]
D. HYDROGEN STORAGE — REGIONAL SALT CAVERN POTENTIALS (exogenous, constant over the horizon)									
Salt cavern potential	Total usable potential	TWh	8 828	8 828	8 828	8 828	8 828	8 828	Onshore + nearshore summed over all nodes
E. HYDROGEN TRANSPORT									
H2 pipeline (new)	Investment (CAPEX)	EUR/MW/km	382	382	382	382	382	382	
H2 pipeline (new)	Annualised capital cost	EUR/MW/km/yr	41.4	39.8	38.2	36.6	35.0	33.4	Declines only through the falling FOM rate
H2 pipeline (new)	Fixed O&M	% of CAPEX/yr	3.58	3.17	2.75	2.33	1.92	1.50	
H2 pipeline (new)	Compression electricity	MW _e /1000 km/MW _{H₂}	0.020	0.019	0.0185	0.018	0.0175	0.017	
H2 pipeline (new)	Technical lifetime	years	50	50	50	50	50	50	

Technology (PyPSA carrier)	Parameter	Unit	2025	2030	2035	2040	2045	2050	Source / note
H2 pipeline retrofitted	Investment (CAPEX)	EUR/MW/km	163	163	163	163	163	163	"H2 (g) pipeline repurposed". 43 % of new-build cost
H2 pipeline retrofitted	Annualised capital cost	EUR/MW/km/yr	17.6	17.0	16.3	15.6	14.9	14.2	
H2 pipeline retrofitted	Retrofit capacity ratio	MW _{H2} /MW _{CH4}	0.60	0.60	0.60	0.60	0.60	0.60	
H2 submarine pipeline	Investment / FOM / lifetime	EUR/MW/km, %, yr	573 / 3.0 / 30	←	←	←	←	←	Constant over the horizon
F. FINANCIAL PARAMETERS (HURDLE RATES AND ANNUALISATION)									
All H ₂ technologies	Discount rate / WACC	per unit	0.07	0.07	0.07	0.07	0.07	0.07	Every H ₂ technology carries 0.07. Only decentral heating and rooftop PV carry 0.04
Model-wide	Social discount rate	per unit	0.02	0.02	0.02	0.02	0.02	0.02	
All technologies	Annualisation	—	annuity + FOM	←	←	←	←	←	Annualised CAPEX = investment × [r / (1 - (1+r) ⁻ⁿ) + FOM], with r = 0.07 and n the technical lifetime
All technologies	Cost year	—	2025	2030	2035	2040	2045	2050	Under myopic foresight the cost year follows the planning horizon
All technologies	Currency base year	—							Harmonised during cost preparation; the currency_year column is not retained in the processed files. To be read from the code
Cost database version	technology-data release	—	v0.14.0	←	←	←	←	←	
G. OPERATIONAL SETTINGS FROM THE CONFIGURATION									
H2 Electrolysis	Share of waste heat recoverable to DH	per unit	0.25	0.25	0.25	0.25	0.25	0.25	
H2 Fuel Cell	Share of waste heat recoverable to DH	per unit	1.00	1.00	1.00	1.00	1.00	1.00	
H2 Electrolysis	Maximum new EU capacity per horizon	GW	200	200	200	200	200	200	
Shipping H ₂	Liquefaction required	—	No	No	No	No	No	No	Liquefaction CAPEX not incurred

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[www. CLIMACT.com](http://www.CLIMACT.com)

info@CLIMACT.com

+32 (0) 10 750 740