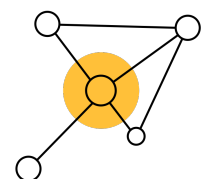
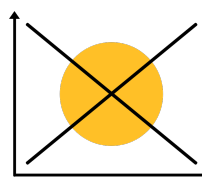
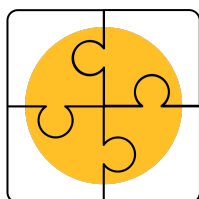
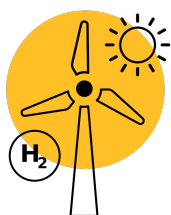


## Green hydrogen production under RFNBO criteria

Analyzing the system and business case perspective

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The Institute of Energy Economics at the University of Cologne (EWI) is a non-profit organization dedicated to applied research in energy economics and energy business informatics and carries out consulting projects for business, politics and society. Managed by Sylwia Bialek-Gregory, Ph.D. (Executive Manager Research & Consulting) and Annette Becker (Executive Manager Commercial), a team of about 40 employees prepares energy economic analyses with high practical relevance. Professor Dr. Marc Oliver Bettzüge from the Department of Economics of the University of Cologne, is the director of the institute.

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## Executive Summary

Green hydrogen is expected to play a key role in achieving European decarbonization targets, especially in industry and electricity generation sectors. To ensure sustainability, the EU has introduced criteria that define **Renewable Fuels of Non-Biological Origin (RFNBO)** under the Renewable Energy Directive II (RED II). These include additionality, geographical correlation, and temporal correlation, intended to ensure that hydrogen production aligns closely with renewable electricity generation and does not adversely impact existing renewable capacities and imply additional greenhouse gas emissions.

This study analyzes the implications of these RFNBO criteria from two perspectives: Firstly, it examines the **impact on the European energy system** by employing the HYEBRID model, a linear, hourly-resolved partial equilibrium model. The model co-optimizes investment and dispatch decisions for the European electricity and hydrogen sector from a system-wide perspective under the assumption of perfect coordination. Several scenarios reflecting varying degrees of RFNBO criteria are evaluated, along with sensitivities addressing electrolyzer investment costs, import availability, storage potential, and hydrogen production targets. Secondly, the implications of the RFNBO criteria are examined from a **business perspective**. In that context, particular attention is paid to the project-level economics and the resulting impact on hydrogen production costs in an exemplary business case. Figure 1 gives an overview of the modeling approach and key results.

On the *system level*, the results show that applying the full RFNBO criteria (including hourly matching) may increase **average hydrogen costs** across Europe by approximately 10 EUR/MWh. The cost increase is primarily driven by additionality requirements and the shift to hourly matching. Concurrently, stricter RFNBO criteria result in a marginal reduction in electricity costs by about 5 EUR/MWh due to surplus renewable electricity being traded to the market. This reflects a distributional effect, shifting additional system costs primarily to hydrogen producers. From a *business perspective*, the cost increase due to the RFNBO criteria may be more pronounced. Introducing an hourly matching requirement is associated with an increase of the **levelized cost of hydrogen (LCOH)** of just under 30 EUR/MWh. The tightening from monthly to hourly is associated with an increase of nearly 22 EUR/MWh. In the absence of flexibility (e.g. battery and hydrogen storage) and a requirement to produce a baseload profile, this cost increase can become even more pronounced.

In conclusion, while RFNBO criteria ensure a **sustainable alignment between renewable energy generation and hydrogen production**, they may also raise hydrogen costs and introduce distributional effects between the electricity and hydrogen sectors. It is important to note that these results represent optimal scenarios under perfect coordination and perfect foresight. Real-world **operational complexities** and procurement challenges could further increase the challenges associated with the RFNBO criteria. Figure 1 summarizes how the individual criteria might influence the energy system and the planning and operation of electrolyzer projects.

|             |                               | Analyzing Green Hydrogen Production under RFNBO Criteria                                                                                                                                                                                                                                                                                                             |                                                                                                                                                                                                                                                                                                                                                                                                  |
|-------------|-------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
|             |                               | System Perspective                                                                                                                                                                                                                                                                                                                                                   | Business Perspective                                                                                                                                                                                                                                                                                                                                                                             |
| Methodology | Goal & Scope                  | <ul style="list-style-type: none"> <li>System-level analysis of green hydrogen production in the European Energy System</li> </ul>                                                                                                                                                                                                                                   | <ul style="list-style-type: none"> <li>Business-level analysis of green hydrogen production at an exemplary project in Germany</li> </ul>                                                                                                                                                                                                                                                        |
|             | Prevailing Market Environment | <ul style="list-style-type: none"> <li>Fully developed, liquid hydrogen market</li> <li>Perfect coordination among participants</li> <li>Advanced cost degression and infrastructure ramp-up</li> </ul>                                                                                                                                                              | <ul style="list-style-type: none"> <li>Project planning under status quo</li> <li>Imperfect coordination among participants</li> <li>Current asset cost estimates</li> </ul>                                                                                                                                                                                                                     |
|             | Modeling Approach             | <ul style="list-style-type: none"> <li>Partial equilibrium model of European electricity and hydrogen market</li> <li>Minimizing total system costs</li> <li>Quantifying electrolysis, RES and storage capacities and their regional distribution</li> <li>Analysis of the impact on marginal costs of hydrogen, electricity and CO<sub>2</sub> emissions</li> </ul> | <ul style="list-style-type: none"> <li>Optimization model for hydrogen production from business perspective</li> <li>Minimizing site-specific levelized cost of hydrogen</li> <li>Sizing and operation of hydrogen production system, consisting of electrolyzer, PPA portfolio, battery and hydrogen storage, and wholesale market interactions (purchases and sales) as price taker</li> </ul> |
| Key Results | Hydrogen Costs                | <ul style="list-style-type: none"> <li>Implementing all <i>All Criteria</i> increases average hydrogen costs by +8% compared to <i>No Criteria</i></li> <li>Stricter RFNBO criteria lead to excess renewable electricity, resulting in a slight decline in electricity costs and a tendency toward lower emission costs.</li> </ul>                                  | <ul style="list-style-type: none"> <li>LCOH are more sensitive to the RFNBO criteria: Implementing <i>All Criteria</i> raises LCOH by 19% as compared to the <i>No Criteria</i> case.</li> <li>Effect on electricity prices is not within the scope of model</li> </ul>                                                                                                                          |
|             | Installed Capacities          | <ul style="list-style-type: none"> <li>Electrolyzer capacity increases slightly with RFNBO criteria; full-load hours are lower</li> <li>Stricter matching, shifts hydrogen production towards high-FLH wind regions, reducing PV utilization for electrolysis and increasing PV feed-in to the power market.</li> </ul>                                              | <ul style="list-style-type: none"> <li>Stricter RFNBO criteria require more dedicated RES and short-term flexibility; tighter correlation requirements increase PPA capacities of PV and battery storage</li> <li>Adding hydrogen storage shifts flexibility from power to hydrogen, lowering required PPA capacity and curtailment</li> </ul>                                                   |
| Conclusions | Additionality                 | <ul style="list-style-type: none"> <li>Separates RES capacity into market and hydrogen-dedicated segment</li> <li>Tightens the PPA market particularly for green hydrogen</li> </ul>                                                                                                                                                                                 |                                                                                                                                                                                                                                                                                                                                                                                                  |
|             | Geographical Correlation      | <ul style="list-style-type: none"> <li>Reduces the ability to balance low-yielding local resources with stronger ones elsewhere</li> <li>Shrinks the accessible PPA pool (e.g. for German projects) and thereby increases competition for assets within the respective bidding zone</li> </ul>                                                                       |                                                                                                                                                                                                                                                                                                                                                                                                  |
|             | Temporal Correlation          | <ul style="list-style-type: none"> <li>Stricter matching raises flexibility needs and lowers electrolyzer full-load hours</li> <li>Hourly matching makes results highly sensitive to supply profile, storage availability, trading options, and market exposure</li> </ul>                                                                                           |                                                                                                                                                                                                                                                                                                                                                                                                  |

Figure 1: Outline of the methodological approach and key results

# 1 Introduction

Green hydrogen is set to play a significant role in the decarbonization of the energy system. As an energy carrier for the industrial, transport, and the electricity sector, hydrogen may be used as an alternative to fossil fuels. Therefore, a ramp up of a hydrogen infrastructure including hydrogen production via electrolysis is strived for. The regulatory framework for the hydrogen ramp-up at the European level is largely determined by the definition of Renewable Fuels of Non-Biological Origin (RFNBO) and the resulting criteria for the production of green hydrogen (European Commission, 2023). These RFNBO criteria are designed to create a foundation for comparable and competitive EU-wide conditions and to ensure the system suitability of hydrogen production as the energy system becomes increasingly reliant on renewable electricity.

**Regulatory framework** According to the EU Delegated Act on RFNBO, to be qualified as "green", hydrogen production must follow rules illustrated in Figure 2. Accordingly, green hydrogen may be produced with a direct connection to a renewable energy plant. When using a grid connection for electricity supply, the electrolyzer may use electricity within a bidding zone with a renewable energy (RE) share above 90% (with a full-load hour limit for the hydrogen production), use RE surplus electricity or use a power purchase agreement (PPA). In the case of a PPA, the additionality, temporal correlation, and geographical correlation criteria must be fulfilled. Member states were required to transpose these criteria into national legislation. In Germany, this is implemented in the Federal Immission Control Act (BImSchG<sup>1</sup>).

This analysis focuses on the RFNBO criteria for green hydrogen production as applied to PPAs: additionality, temporal correlation, and geographical correlation, highlighted in red in Figure 2. The focus on PPAs reflects the goal of the analysis: to quantify the effects of the RFNBO criteria (i) on the transition of the European Energy System and (ii) on hydrogen production costs of individual electrolysis projects in Germany. Other compliance paths are not covered<sup>2</sup>.

The EU provided its reasoning behind the definition of the green hydrogen production. Accordingly, the additionality condition is meant to prevent hydrogen production from displacing renewable energy that would otherwise be used to meet existing electricity demands and thus to decrease overall CO<sub>2</sub> emissions (Hydrogen Europe, 2023). Temporal correlation requirement ensures that green hydrogen is only produced when renewable energy is available. This approach is intended to reduce CO<sub>2</sub> emissions by avoiding the use of non-renewable energy sources during periods of low renewable generation (EWI, 2022). Geographical correlation requires that the renewable electricity used for hydrogen production comes from regions with abundant renewable resources. This shall ensure that hydrogen production does not contribute to grid congestion between bidding zones and that the renewable energy used is locally available, proposing an increase in the efficiency of the system (Hydrogen Europe, 2023).

---

<sup>1</sup>Federal Immission Control Act (Bundes-Immissionsschutzgesetz), 10th of May 2023.

<sup>2</sup>The analysis of the other paths requires very detailed modeling of the electricity grid as well as non-linear constraints, which goes beyond the scope of this study. The island approach of the direct connection is analyzed with the EWI Global PtX Cost Tool (EWI, 2025).

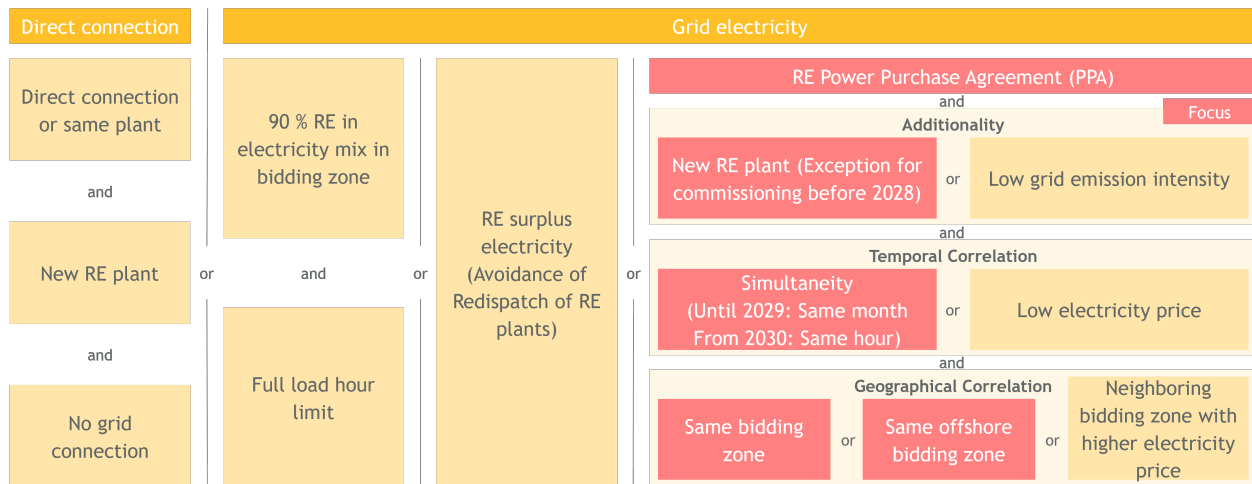


Figure 2: Overview of the criteria for renewable fuels of non-biological origin (RFNBO)

While the RFNBO criteria are designed to promote sustainability, they have raised concerns among stakeholders, particularly regarding their impact on the scalability and cost-effectiveness of hydrogen production. Additionality has been criticized for reducing the renewable electricity available for hydrogen production, thereby increasing hydrogen costs. This limitation may be hindering the development of a hydrogen market. (Frontier Economics, 2021). Temporal correlation has led to concerns about the viability of hydrogen production when renewable energy is not continuously available. This criterion may result in lower full-load hours of hydrogen production due to periods of low renewable generation, or higher investments in energy storage to ensure continuity. The increased reliance on storage could drive up costs and create challenges in meeting hydrogen demand (Hydrogen Europe, 2023). Geographical correlation has raised issues related to uncertainty and costs. Since renewable energy availability is not evenly distributed across regions, this requirement could restrict hydrogen production to areas with abundant renewable resources. This may increase logistical challenges and create inefficiencies in the hydrogen supply chain. (Frontier Economics, 2021) Furthermore, some stakeholders argue that these criteria are stricter than those applied to other sectors like heat pumps (HP) and electric vehicles (EVs), as they are considered green technologies while using electricity from the grid without any constraints.

**Literature overview** Several studies have explored the impact of the RFNBO criteria on the levelized costs of hydrogen (LCOH) and CO<sub>2</sub> emissions. Frontier Economics (2021) analysed the effects of the criteria from a business development perspective and found that incorporating the RFNBO criteria, particularly the additionality and temporal correlation of quarter-hourly matching requirements, may significantly increase hydrogen production costs. The study estimates that production costs rise from around 2.8 EUR/kg to 5.1 EUR/kg, an increase of +2.3 EUR/kg when complying with the criteria. Brauer et al. (2022), in a study focused on minimizing LCOH, found a smaller impact on costs. According to their analysis, costs only increased by about 0.1 EUR/kg when comparing hydrogen production under the RFNBO criteria to grid-based produc-

tion. Ruhnau & Schiele (2022), as well as Zeyen et al. (2024), focused on minimizing LCOH and total annual system costs, respectively. Both studies concluded that hourly matching requirements under the RFNBO Delegated Acts could significantly raise costs if energy storage systems are either unavailable or prohibitively expensive. The need to match production with renewable energy availability on an hourly basis adds complexity and increases costs, especially in regions or markets where affordable storage solutions are not accessible. However, the findings regarding the impact of the RFNBO criteria on CO<sub>2</sub> emissions remain ambiguous.

**Scope of this Analysis** This study examines the impact of the RFNBO criteria from two perspectives: (i) a system perspective and (ii) a business perspective. In the first part, the focus is set on the impact on the transition of the electricity system as well as average electricity, hydrogen, and CO<sub>2</sub> emission costs in Europe. This is achieved by using an energy system modeling approach, which minimizes total annual system costs. The second part evaluates the criteria from a business perspective, analyzing how they affect investment and operational decisions and, consequently, hydrogen production costs in a representative project.

The system and business perspectives differ in scope and focus. The former adopts a broad, system-oriented view grounded in welfare economics and resource allocation theory, emphasizing how policies, institutions, and incentives shape market efficiency and societal welfare. Partial equilibrium models, like the one used in this part, typically assume perfectly functioning, competitive, and complete markets with perfect coordination of market participants, treating the system planner's problem as the dual of the market outcome while ignoring market frictions. In contrast, the business perspective is organization-centered, emphasizing firm-level decision-making in areas such as strategy, finance, and operations. It examines how individual organizations respond to market conditions and regulatory frameworks to remain competitive and sustainable. Business case analyses adopt the perspective of an individual agent and explicitly account for such frictions and imperfections. This creates a natural divergence between the two approaches when evaluating regulatory instruments. Considering both perspectives allows for a clearer understanding of how system-level assumptions differ from firm-level realities and provides insights from the resulting contrasts.

This report commences with the system perspective, followed by the business perspective. In both parts, the RFNBO criteria are implemented stepwise. An analysis of the geographical and additionality criterion is followed by adding monthly, daily or hourly matching. For each step, results indicate effects on marginal costs of electricity and hydrogen as well as the CO<sub>2</sub> emissions. Correlation-only cases are not presented; temporal and geographical correlation are assessed only together with additionality.

## 2 System Perspective on RFNBO for Hydrogen Production

This chapter analyzes the effects of RFNBO criteria from a system point of view. An energy system model is used to optimize investments and operations across the European power and hydrogen sector, quantifying how additionality, as well as geographical and temporal matching rules, shift costs and capacities at system level. Section 2.1 details the methodology and input assumptions; Section 2.2 presents the results.

### 2.1 Modeling the European Energy System with HYEBRID

#### 2.1.1 Model Description

The analysis utilizes HYEBRID energy system model, developed at EWI, to determine the impact of the RFNBO criteria on the European electricity and hydrogen markets. HYEBRID is a linear partial equilibrium model that minimizes the total annualized system costs of the electricity and hydrogen sectors. Therefore, HYEBRID simultaneously models equilibria within the electricity and hydrogen markets and their interdependence while determining the optimal capital stock. The geographical framework comprises the EU-27 (excluding Bulgaria, Malta, and Cyprus), as well as Norway, Switzerland, and the United Kingdom<sup>3</sup>.

HYEBRID features hourly resolution with perfect foresight. It co-optimizes investments and dispatch planning of conventional power plants, fluctuating renewable generation plants, and storage systems to meet an hourly demand for electricity and hydrogen. Figure 3 gives a schematic overview of the HYEBRID model. All model solutions must comply with an exogenous EU-wide CO<sub>2</sub> emissions cap. In an integrated investment and dispatch run, HYEBRID allows the simultaneous decision on capacity additions and hourly operation of generation, conversion, transport, and storage units, minimizing total system costs (Keutz & Kopp, 2025).

To implement the RFNBO additionality criterion, PPAs are treated as a separate asset class in HYEBRID, as shown in Figure 4. The electricity from these newly constructed wind and PV plants is primarily used for hydrogen production. However, surplus electricity can be sold on the wholesale market. The cumulative renewable potential per country remains restricted by resource and area limits. Optional constraints allow for the spatial and temporal correlation between PPA generation and electrolysis.

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<sup>3</sup>Throughout the remainder of this document, the model region is referred to simply as Europe (abbr. EU).

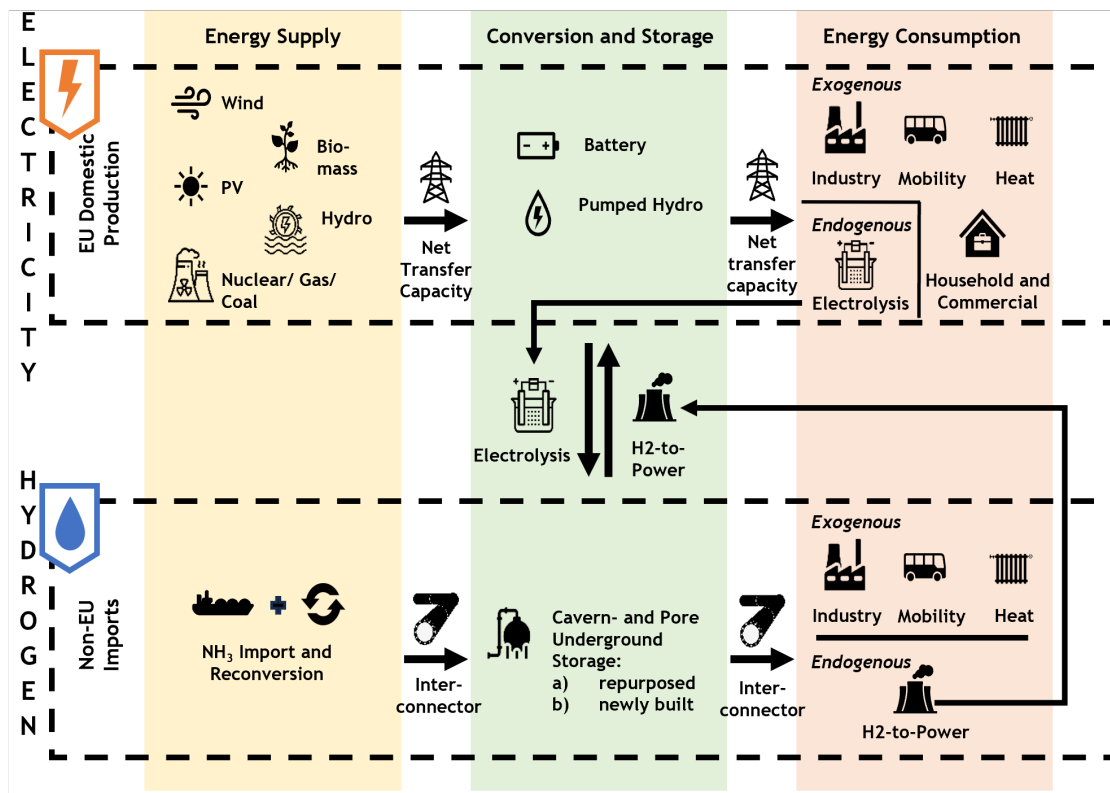


Figure 3: Graphical display of energy system model HYEBRID

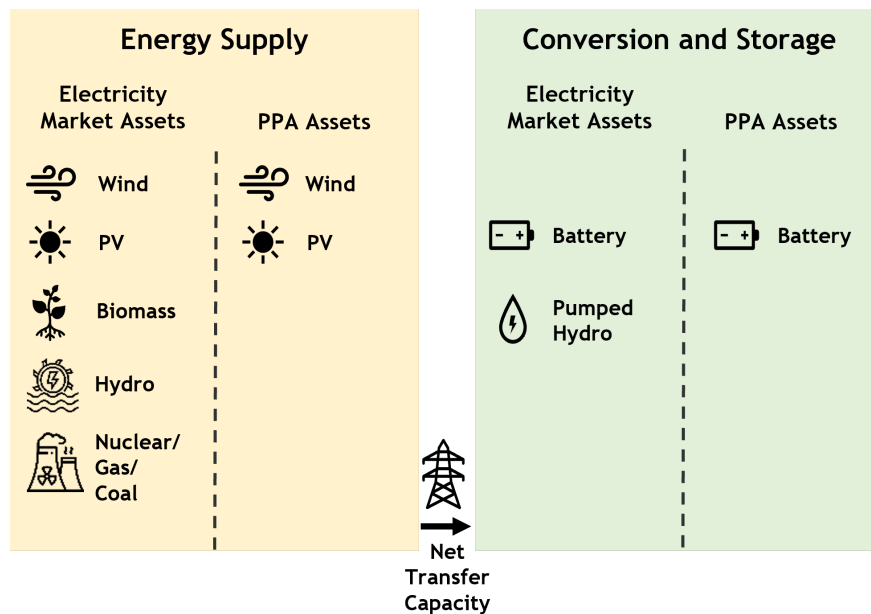


Figure 4: New PPA classes in HYEBRID

### 2.1.2 Data and Assumptions

For the modeling data basis, a single representative year is chosen, which reflects an ongoing hydrogen market ramp-up with an EU-wide hydrogen transport infrastructure. The techno-economic assumptions of the National Trends Scenario of the ten-year network development plan (TYNDP) 2024 (ENTSO-E & ENTSOG, 2024) for the year 2030 serve as a structural guideline. However, so far, the EU-wide hydrogen demand and production ramp-up has been slower than expected in the TYNDP. The analysis therefore does not necessarily represent the year 2030, but a market state in which the key elements of the ramp-up have already developed (production, cross-border infrastructure and demand).

**Weather** The hourly time series uses the weather year 2005, which is identified as a representative weather year using a clustering approach (Keutz & Kopp, 2025). From all years 1982-2016, the hourly residual load of the selected year has the smallest Euclidean distance to the average profile of all years. This means that 2005 best reflects the average past meteorological conditions in Europe and avoids distortions caused by exceptionally favorable or unfavorable renewable energy conditions.

**Electricity demand, generation and transmission** The country-specific annual demand is based on the National Trends Scenario of the TYNDP 2024 (ENTSO-E & ENTSOG, 2024). To generate the hourly load profile, the values are scaled with the temperature and weather-dependent time series of the European Resource Adequacy Assessment (ERAA) dataset for the weather year 2005 (ENTSO-E, 2021). Figure 5 shows the resulting annual electricity demand (yellow bars) and the minimum shares of renewable electricity generation of each country (red dots) derived from the national energy and climate plans (NECPs). These minimum quotas apply on an annual basis and explicitly exclude the electricity required by electrolyzers.

The installed generation and storage capacities for 2024 serve as the starting capital stock (ENTSO-E, 2025). Further expansion of installed generation is determined endogenously in the modeling process, but is confined by the technical upper limits of the TYNDP scenario National Trends 2030. Fixed expansion paths, as in the EEG or other strategies, are not specified. In this way, HYEBRID can independently determine which combination of onshore wind, offshore wind, and PV is economically viable, as long as the respective country potentials are not exceeded. Additional electricity demand due to electrolysis and storage losses arises endogenously during optimization: HYEBRID adjusts electrolysis and storage dispatch so that the system cost minimum is achieved while complying with the CO<sub>2</sub> upper limit.

Limits to cross-border electricity trading arise through the net transfer capacities (NTCs). For European interconnectors, we use the NTCs planned for 2030 based on the TYNDP 2024. For trade between Germany and its neighbors, we rely on NTCs from the German grid development plan (ENTSO-E & ENTSOG, 2024; 50Hertz Transmission GmbH et al., 2023). We ignore grid restrictions

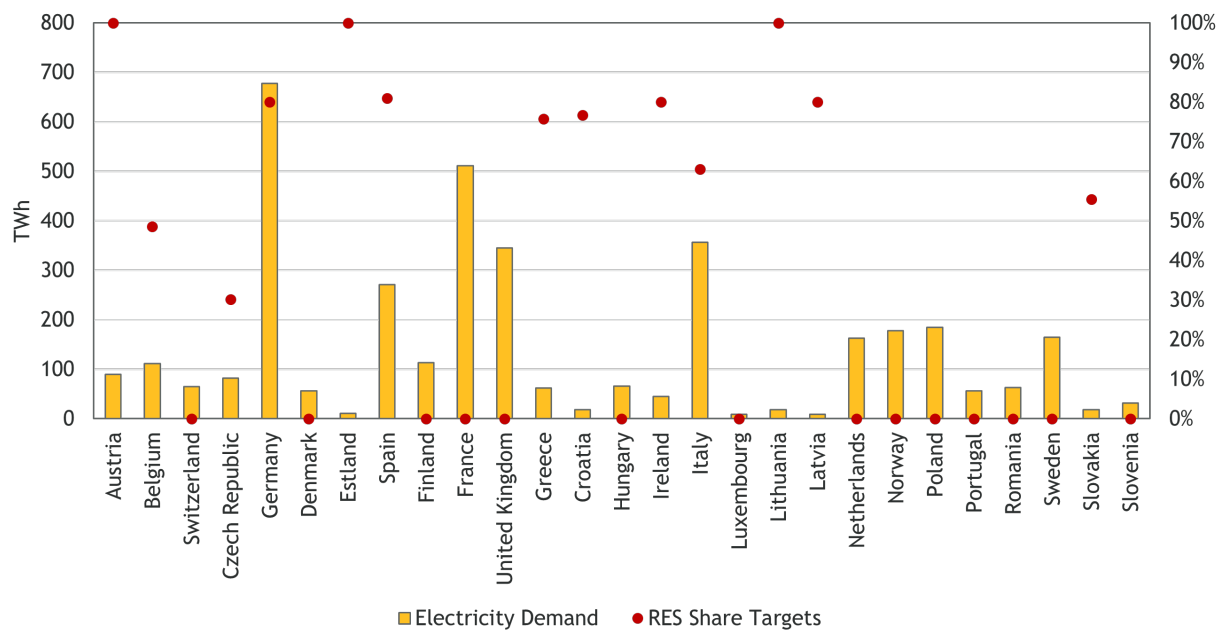


Figure 5: Exogenous electricity demand and green electricity target per country

within countries. HYEBRID models demand-side management (DSM) as virtual storage: up to 5% of the national peak load can be shifted by a maximum of two hours.

**Hydrogen demand, production and transmission** The green hydrogen demand per country is also taken from the National Trends Scenario of the TYNDP 2024 (ENTSO-E & ENTSOG, 2024). Aggregated across all modeled countries, this amounts to about 400 TWh per year. The annual volumes (yellow bars in figure 6) are distributed as a hourly constant base load to reflect the continuous demand, primarily from the industry. National production targets (red dots) are derived from reported electrolysis capacity targets multiplied by 4000 full-load hours. This means that no minimal electrolysis capacity is specified; HYEBRID expands the capacities endogenously as long as the respective annual production is reached. With this approach, the model reflects existing and actively pursued hydrogen strategies of individual countries while enabling the endogenous expansion and dispatch of electrolysis capacity. In addition, non-EU imports (gray bars) and blue hydrogen in Norway (blue bar) are given as cost-neutral baseload supply. The volume of 167 TWh per year ( $\approx 38\%$  of demand) and the importing countries of non-EU imports correspond to the National Trends reference path.

For cross-border hydrogen transport, HYEBRID adopts the reference grid of the TYNDP 2024. As a modeling assumption, selected investment candidates from TYNDP 2024 are additionally included to ensure that all model countries are physically linked to the European hydrogen system. The pipeline capacities are constant; the model does not permit investments in additional pipelines. Losses due to cross-border transport are accounted for at a flat rate of 1% of the hydrogen quantity transported.

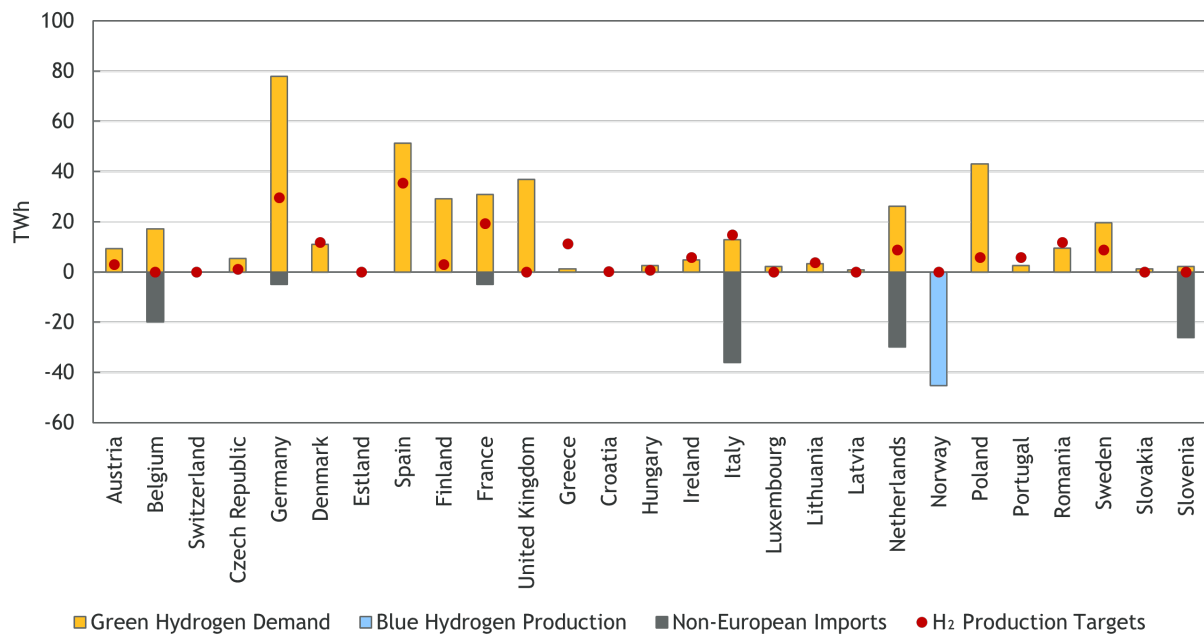


Figure 6: Exogenous green hydrogen demand, production targets and ship imports per country

In the HYEBRID model, four hydrogen storage technologies are distinguished:

1. repurposed natural gas caverns,
2. newly built hydrogen caverns,
3. repurposed natural gas pore storage facilities and
4. newly built hydrogen pore storage facilities.

The storage volumes are aggregated per country - there are therefore no site or facility-specific restrictions within a country. Repurposing potentials are based on the progressive decline in demand for natural gas. A maximum of 23% of today's natural gas storage facilities can be converted to hydrogen in the reference year. New cavern construction potential is limited by geological salt structures (offshore deposits are excluded due to high costs). Pore storage facilities may only be built in countries that already operate natural gas pore storage facilities; their potential is not additionally limited due to a lack of reliable data. The assumptions are based on EWI (2024).

**Costs** Table 1 and Table 2 show an overview of key cost assumptions. Investment and operating costs for new RES technologies are based on EWI (2025). Electrolysis capital expenditures (CAPEX) are assumed at 1000 EUR/kW. Hydrogen storage costs are taken from EWI (2024).

Table 1: Specific investment cost of RES technologies, electrolysis, and battery storage, Source: (EWI, 2025)

| Technology       | CAPEX | Unit    |
|------------------|-------|---------|
| Onshore Wind     | 1 242 | EUR/kW  |
| Offshore Wind    | 2 438 | EUR/kW  |
| Utility-scale PV | 588   | EUR/kW  |
| Electrolyzer     | 1 000 | EUR/kW  |
| Battery Storage  | 478   | EUR/kWh |

Table 2: Specific investment costs of hydrogen storage by storage category, Source: (EWI, 2024)

|                | Cavern storage |           | Pore storage |           | Unit    |
|----------------|----------------|-----------|--------------|-----------|---------|
|                | Conversion     | New build | Conversion   | New build |         |
| Storage volume | 190.1          | 234.6     | 205.9        | 244.8     | EUR/MWh |
| Injection      | 163.3          | 163.3     | 227.8        | 227.8     | kEUR/MW |
| Withdrawal     | 163.3          | 163.3     | 182.2        | 182.2     | kEUR/MW |

### 2.1.3 Scenario Design

Table 3 summarizes the six main scenarios of this analysis. The *No Criteria* reference case represents a market design without RFNBO requirements: electrolyzers can purchase electricity freely on the wholesale market without having to comply with additionality, geographical or temporal correlations. In all other cases, additionality applies - every electrolyzer capacity in operation must be backed by newly built wind or PV plants. As part of the PPA portfolio, battery storage can be built to buffer PPA generation; these batteries may discharge to the market but may only charge from PPA-linked assets. Geographical and temporal correlation are gradually added.

Table 3: Scenario overview according to the incorporation of RFNBO criteria

| Scenario label      | Additionality      | Geographical correlation           | Temporal correlation |
|---------------------|--------------------|------------------------------------|----------------------|
| No Criteria         | -                  | -                                  | -                    |
| Add   No Geo   Year | New RE plants only | -                                  | Annual Matching      |
| Add   Geo   Year    | New RE plants only | New RE plants in same bidding zone | Annual Matching      |
| Add   Geo   Month   | New RE plants only | New RE plants in same bidding zone | Monthly Matching     |
| Add   Geo   Day     | New RE plants only | New RE plants in same bidding zone | Daily Matching       |
| Add   Geo   Hour    | New RE plants only | New RE plants in same bidding zone | Hourly Matching      |

In the *Add | No Geo | Year* scenario, the model does not include geographical correlation, but it still requires additionality through the use of newly built RES plants. The RES power plant of the PPA might be located in a different country than the electrolyzer. The net transfer capacity limits of the international electricity grid constrain these bilateral electricity flows in addition to those associated with wholesale electricity trading. Market participants can sell surplus PPA electricity either in the country of generation or in the country of consumption. Temporal corre-

lation is enforced on an annual basis in this scenario: the sum of annual PPA generation must be equal or higher than the electrolyzer's annual electricity consumption, and market participation is allowed within the year as long as this balance is met. As a result, PPAs in this scenario allow a Europe-wide allocation of renewable capacities, provided that the annual energy balance between generation and electrolysis remains satisfied.

The remaining scenarios also incorporate a simplified geographical correlation requirement (*Add | Geo | Year/Month/Day/Hour*): the generation plant and electrolyzer must be located in the same country, as the model only maps one bidding zone per country. The temporal correlation requirement is progressively tightened from annual to monthly, daily and ultimately hourly matching. Figure 7 illustrates the market mechanics of all scenarios: PPA surpluses may always be fed into the electricity market. In scenarios with matching coarser than hourly, the electrolyzer may procure electricity from the market as long as the total PPA generation equals or exceeds the electricity consumption within the defined time period.

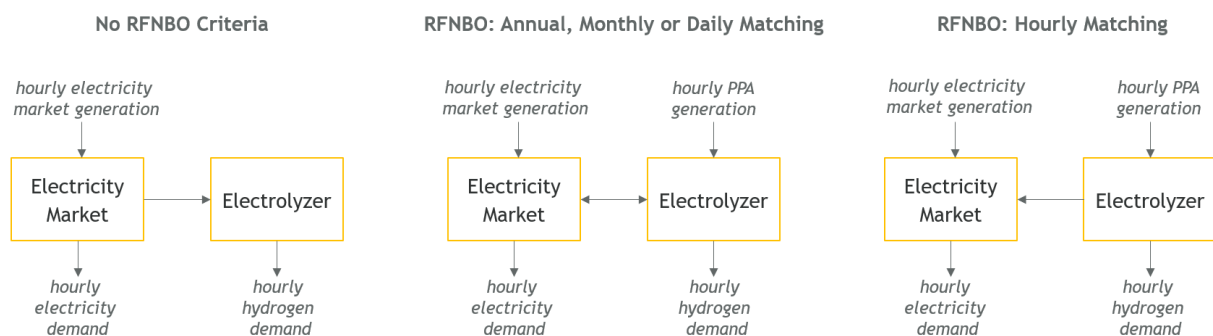


Figure 7: Hydrogen production under RFNBO criteria and its interdependence with the electricity market

**Sensitivities** To assess the robustness of the results from the base scenarios, five sensitivities are modeled, each alternating one key input. This analysis is carried out for the *No Criteria* and *Add | Geo | Hour* scenarios. The comparison of the sensitivities with the two base scenarios enables a differentiated assessment of how technology prices, import dependency, storage availability and production targets influence the interaction of the electricity and hydrogen system under the RFNBO criteria. It also identifies the parameters with the strongest influence on system costs, marginal hydrogen prices, and the required electrolyzer capacity expansion.

- **Electrolysis CAPEX:** The investment costs for PEM electrolyzers decrease from the base value of 1000 EUR/kW to 650 EUR/kW. This corresponds to a very optimistic scenario and shows the extent to which the electrolysis capacities built up depends on the investment costs and the effect of the RFNBO criteria.
- **Non-European Imports:** Exogenous hydrogen import from outside the EU are reduced by 50% to reflect a scenario with limited overseas supplies. This increases the proportion of

demand that is not covered by production targets and imports, but must be provided with additional, endogenous hydrogen production in the EU.

- **H<sub>2</sub> storage capacity:** While underground cavern and pore storage facilities can be expanded to their given potential in the base scenario, only facilities with a final investment decision (FID) are available in this sensitivity. This is set to analyze the system value of large-scale storage facilities regarding more volatile hydrogen production with the RFNBO criteria.
- **No H<sub>2</sub> production targets:** The minimum production targets derived from capacity targets and 4,000 full-load hours are not included in this sensitivity. Electrolyser investments are determined endogenously, driven solely by the objective of minimizing total system costs while still satisfying the RFNBO criteria.

## 2.2 Results: Effects on the European Energy System

This chapter presents the results of the system-level modeling, which evaluates how RFNBO criteria affect the energy system when hydrogen production and CO<sub>2</sub> emission targets must be met. The analysis focuses on key result parameters such as annualized system costs, marginal costs for hydrogen, electricity, and CO<sub>2</sub>, as well as the installed capacities of renewable energy sources and electrolyzers.

### 2.2.1 Cost Impacts

The impact of the RFNBO criteria on the European Energy System is analyzed using total system costs and marginal costs of hydrogen and electricity. In a partial equilibrium model like HYEBRID, the increase of total system costs may be interpreted as welfare losses and marginal costs of electricity and hydrogen may be considered prices under perfect market conditions. For carbon emissions, the marginal costs may be interpreted as certificate prices, as the emissions cap is kept constant throughout the scenarios. Hydrogen and electricity demand is assumed to be fully inelastic. Hence, price changes do not influence the level or time series of the demand.

Figure 8 depicts the increase of EU-wide annualized system costs compared to the scenario without any criteria. Annualized system costs include investment costs as well as operating costs for electricity and hydrogen production and storage. With additionality and annual matching, annualized system costs may rise by approximately 0.5 billion EUR per year in Europe compared to the *No Criteria* scenario. Adding the geographical constraint leads to an additional increase of 0.3 billion EUR per year, showing that from a system view, the usage of PPAs from outside the same bidding zone may lower costs as better RE potentials might be used. Tightening the temporal correlation to monthly and then daily matching adds roughly the same amount of about 0.5 billion EUR at each step. This implies that with all green hydrogen criteria as defined in RFNBO in place, annualized system costs increase by 2.7 billion EUR per year compared to the *No Criteria* scenario.

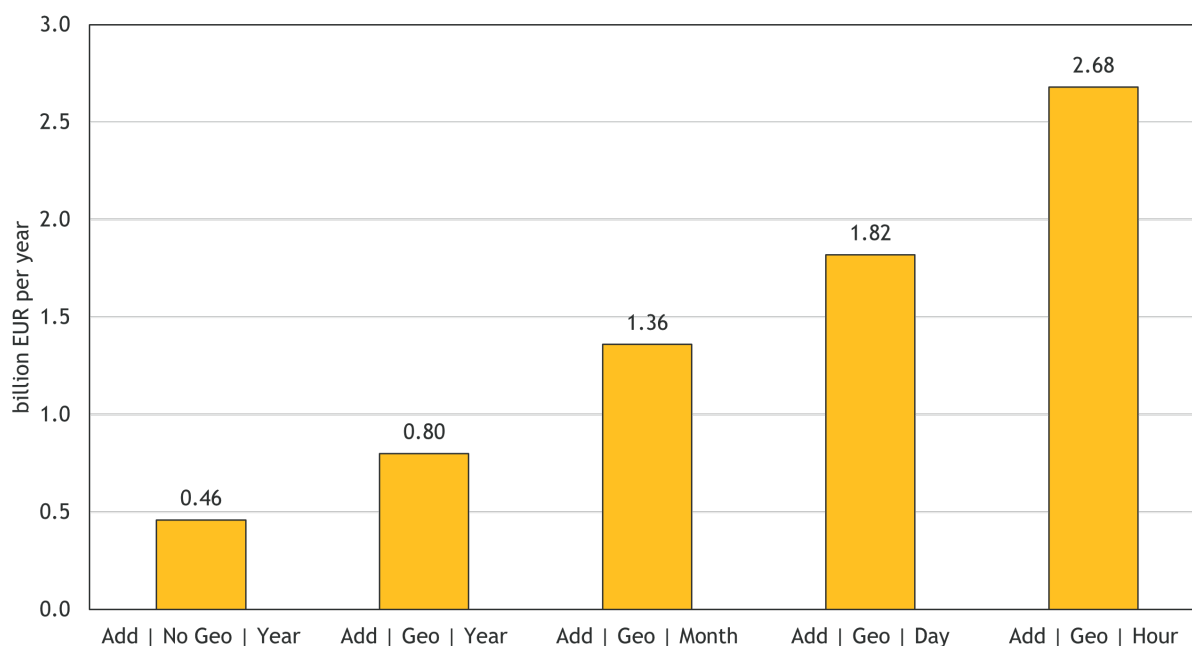


Figure 8: Increase in annualized system costs per year compared to *No Criteria*

Notes: The annualized system costs comprise of annualized investment costs for assets, that are constructed between the start year (2024) and the target year and of FOM and variable costs during the target year. Costs for exogenous assets are not included in the system costs. This applies in particular for all investment costs into transmission infrastructure as well as costs for non-European hydrogen imports.

Figure 9 depicts the weighted average of marginal hydrogen costs across Europe. The marginal costs include electricity costs, investment and operating costs for electrolysis and storage, as well as operating costs for transport<sup>4</sup>. Marginal costs increase by up to 10.5 EUR/MWh (equals 8.4%) under the full set of RFNBO criteria and hourly matching, relative to *No Criteria*. Additivity on its own adds roughly 2 EUR/MWh to the marginal costs of hydrogen. The increase of marginal hydrogen costs when adding geological and temporal (monthly or daily) correlation is rather small. The largest cost increase occurs when the temporal correlation is tightened from daily to hourly matching (+4 EUR/MWh).

The resulting marginal hydrogen costs represent hydrogen prices in an ongoing hydrogen ramp-up with existing international infrastructure and significant demand. However, with this system perspective of a European energy system model, hydrogen production costs of individual projects may be systematically underestimated. This is due to (i) perfect foresight, (ii) perfect market conditions, and (iii) unlimited portfolio effects with the aggregation of all RES and electrolysis plants within each country. In Chapter 3, the business-level analysis of the RFNBO criteria is conducted with a second modeling approach estimating levelized cost of hydrogen to alleviate some of these limitations.

<sup>4</sup>Within the system-wide optimization, the marginal hydrogen costs additionally include the marginal costs of meeting national hydrogen production targets in countries where these targets are binding. These reflect implicit cost contribution necessary to achieve target volumes

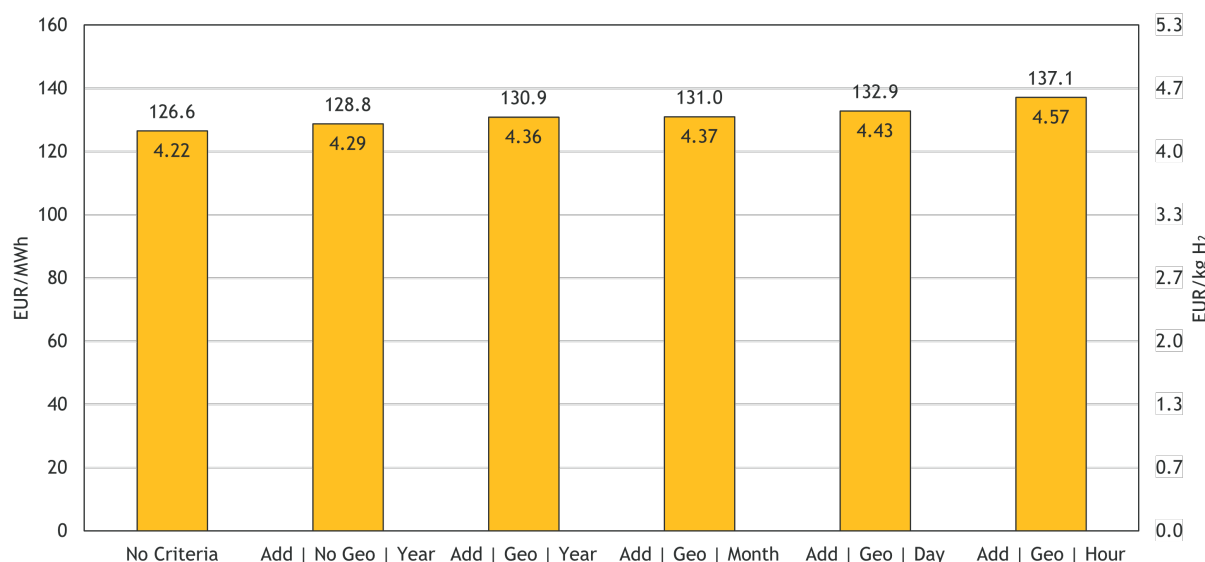


Figure 9: Average marginal costs of hydrogen in Europe

Notes: The marginal costs are the cost for producing one additional unit of hydrogen. Costs of each country have been weighed with production to calculate the European average.

On the electricity market, an opposing effect emerges when implementing RFNBO criteria: average marginal electricity costs decrease by 4.5 EUR/MWh (~5.2%) when all criteria apply, compared to the *No Criteria* scenario (Figure 10). With dedicated PPA procurement, surplus generation from PPA assets can be sold to the wholesale market; however, the PPA costs are attributed to hydrogen production. With tightened RFNBO criteria, additional PPAs must be contracted to meet the hydrogen production, leading to greater volumes of surplus electricity entering the market and thus, lower marginal electricity costs.

These effects on marginal costs highlight a distributional effect induced by the RFNBO criteria between the electricity and hydrogen sectors. While marginal electricity costs decline slightly due to excess renewable generation traded into the market, the additional system costs primarily remain within the hydrogen sector, implying a cost shift from electricity consumers to hydrogen producers.

Figure 11 shows the marginal CO<sub>2</sub> certificate costs with a constant carbon emissions cap in all scenarios<sup>5</sup>. Marginal certificate costs decrease by less than 4 EUR/MWh (~2%) when introducing the RFNBO criteria compared to the *No Criteria* scenario, due to excess renewable electricity from the PPAs that is sold into the market. However, several effects superpose each other. A stricter matching criterion leads to better renewable assets being allocated towards electrolysis, leaving assets with higher abatement costs available to the electricity market. In the case of daily matching, the effect of a less flexible electricity system outweighs the benefits from additional renewable electricity from hydrogen production, causing slightly higher CO<sub>2</sub> prices than in the

<sup>5</sup>The marginal CO<sub>2</sub> costs are determined by the costs of abatement options of the energy sector and the exogenous emissions cap. It is assumed that the CO<sub>2</sub> emissions of the industry sector are constant and independent of electricity and hydrogen prices. The option of bunkering certificates across years is disregarded.

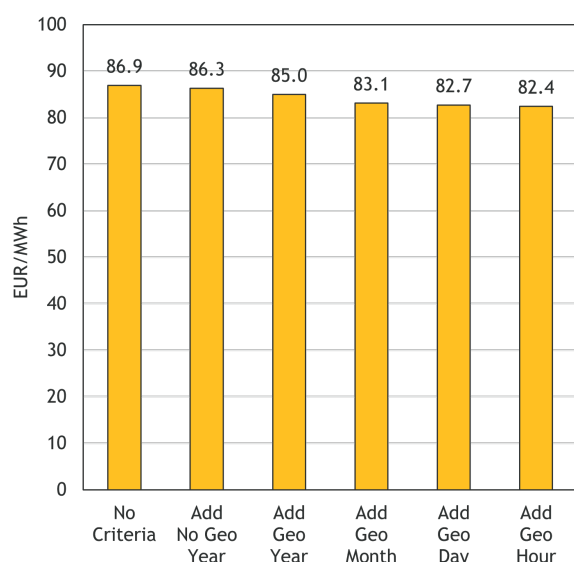
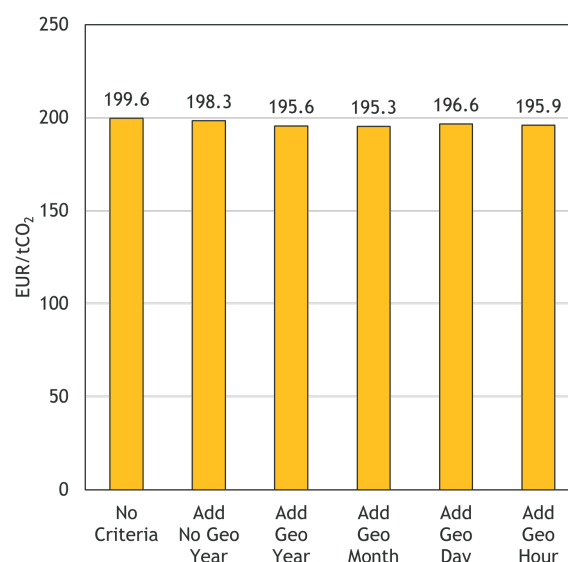


Figure 10: Average marginal electricity costs

Figure 11: Marginal CO<sub>2</sub> certificate costs

monthly matching scenario. Generally, however, the overall impact of stricter RFNBO criteria on CO<sub>2</sub> prices remains limited when the hydrogen demand is inelastic.

The presented results rely on an economic optimization model assuming perfect coordination and optimal procurement strategies. In a real-world business environment, cost increases for a single electrolysis project – particularly under stricter (e.g., hourly) temporal correlation – may be significantly higher. Operational complexities such as more sophisticated procurement strategies, necessary overbuilding of renewable capacities to achieve acceptable full-load hours, and increased operational complexity could substantially raise realized costs. Chapter 3 will address this aspect and analyze the effect of the criteria from a business perspective.

### 2.2.2 Capital Stock

The capital stock of RES generation and electrolysis capacities is endogenously expanded in the model with regard to a cost-effective coverage of the electricity and hydrogen demand. While the RES capacities include plants that were already in operation by the end of 2024, the electrolysis capacity is built from zero. Within the model framework each RFNBO option is evaluated in a separate long-run equilibrium in which the capital stock adjusts endogenously to the regulation; reported differences therefore reflect both operational and investment responses.

Figure 12 shows the EU-wide installed capacities of renewable energies, divided into market and PPA capacities if additionality is considered. Additionality without geographical or temporal correlation has almost no impact on the RES capacities in Europe, as the total capacity increases by only 2 GW<sub>el</sub>. The *Add | Geo | Hour* scenario however results in a capacity increase of 25 GW<sub>el</sub> (equivalent to 2%) in total in Europe compared to the *No Criteria* scenario. The biggest difference can be seen when adding the geographical correlation. Without geographical correlation, PPAs put an emphasis on cheap PV electricity rather than more expensive wind generation. Total RES

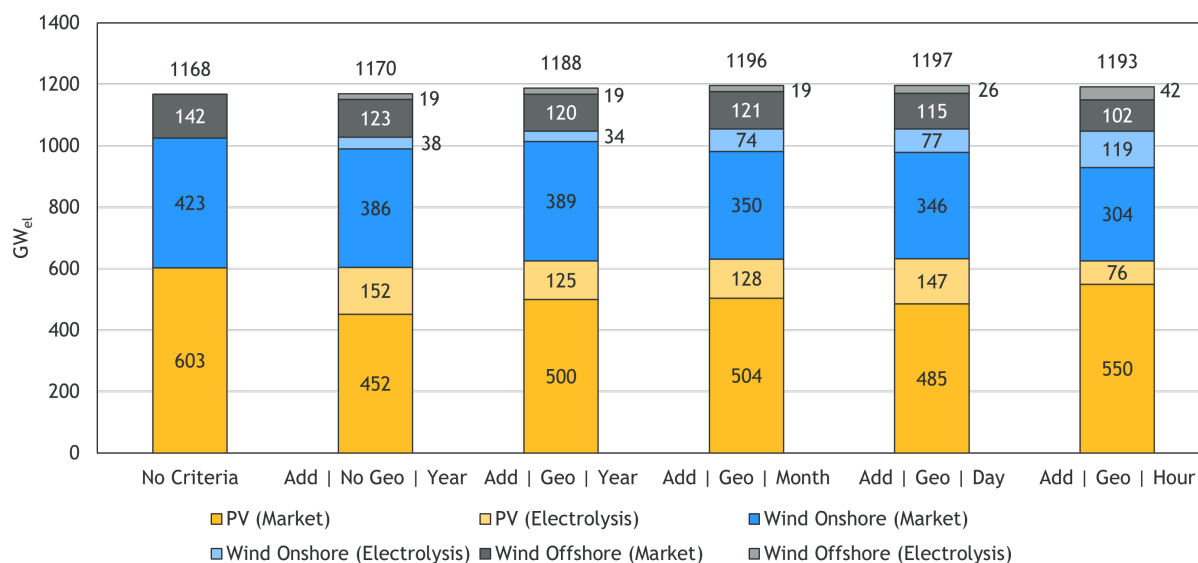


Figure 12: Installed capacities of renewable energies in Europe

*Note: Renewable energies include wind and solar power in this figure, as these sources may be used to produce renewable hydrogen according to the RFNBO criteria. The model itself includes hydropower and biomass according to current capacity.*

capacity shows no significant difference between monthly, daily and hourly matching. However, regarding the RES used for producing hydrogen, daily matching leads to more emphasis on PV. An increase in wind on- and offshore capacities can be seen with tightening temporal correlation due to a production profile that is closer to the demand profile, which is why hourly matching favors wind power with higher full-load hours. The battery charging and discharging power for the electricity market remains between 17 and 20 GW<sub>el</sub> in all scenarios. PPA-linked batteries are only installed under the strict hourly matching scenario, adding 1.5 GW<sub>el</sub> of battery charging and discharging power.

In conclusion, adding RFNBO-Criteria splits RES capacities into hydrogen-dedicated assets and capacity serving the electricity market. With stricter temporal matching requirements, the hydrogen production is in need of RES with high full-load hours (on- and offshore wind), leaving only more volatile RES generation with less full-load hours from solar power to the electricity market.

The PPA electricity balance in Figure 13 shows the amount of electricity that comes directly from the PPAs and that is traded with the electricity market as a sum over Europe. With *No Criteria*, over 350 TWh of electricity for hydrogen production is bought on the market to produce hydrogen to meet the exogenous demand in Europe. In *Add | No Geo | Year*, total PPA generation amounts to 406 TWh: over 40% of PPA production is consumed directly by the electrolyzers, around 50% are sold to the market and a little less electricity is bought back in deficit hours. The red segment reflects cross-border transfer losses (22 TWh) as curtailment does not occur. Under geographical correlation and annual matching, around 60% of the PPA production is directly used. The PPAs feed 150 TWh to the electricity market, and the electrolyzer consumes the same

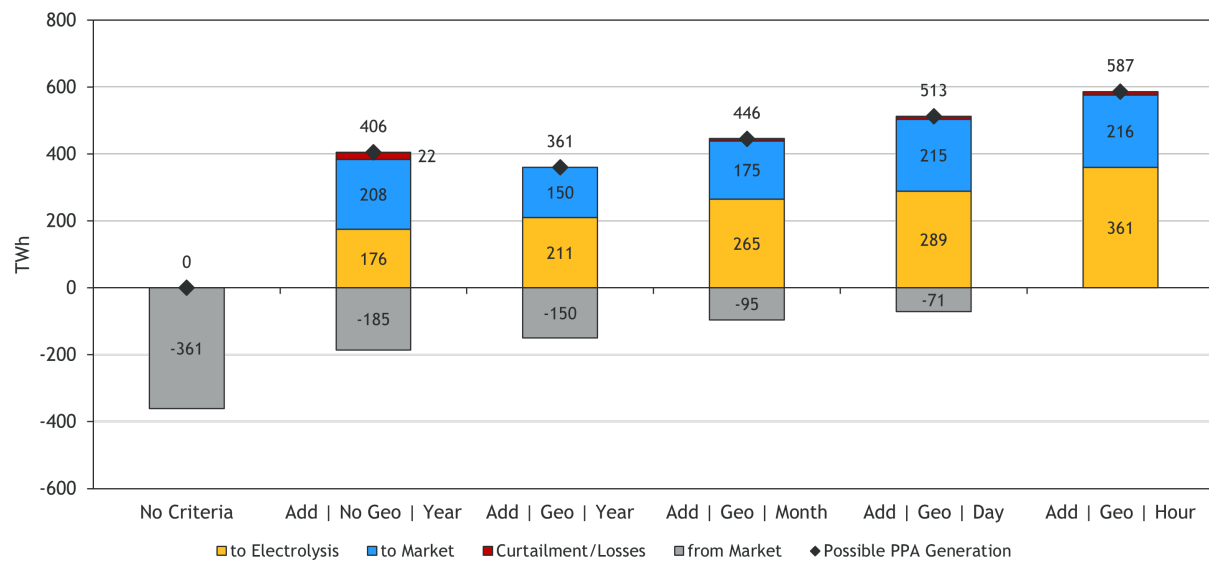


Figure 13: PPA electricity balance as a sum over Europe

amount, resulting in a net market balance of zero to comply to the annual matching. There is no net excess electricity as the PPAs are sized to meet exactly the yearly electricity demand of the hydrogen production. With increasingly strict temporal correlation, the electricity generation of PPAs exceeds the electricity demand of the electrolyzers. In the *Add | Geo | Hour* scenario, the PPA portfolio's production covers the electrolyzers's demand in every hour. A surplus of over 35% of the PPA production is marketed, turning the PPAs into sizeable net producers. Stricter RFNBO criteria increase the RES surplus of PPA assets. For individual electrolysis projects, this can lead to coordination challenges when a more diverse PPA portfolio is to be procured and the excess electricity is to be sold on the electricity market.

Across all scenarios, less than 2% of the PPA generation is curtailed. This low curtailment reflects several model implications: (i) a one-year optimization horizon with capacity endogenously tailored to that year and (ii) perfect foresight and full exploitation of portfolio effects across technologies and time. Higher electrolyzer CAPEX, which would indicate less learning and scaling effects than anticipated in the short to mid term, may also lead to more curtailment as the rate of RES capacity to electrolysis capacity might increase.

In this analysis, hydrogen production targets are defined according to current political goals. The resulting distribution of electrolysis capacity across Europe is significantly driven by those production targets. Figure 14 shows the installed electrolysis capacity by country. While the targets remain binding for most countries, RFNBO criteria change the mix of installed capacity and full-load hours (FLH). Adding the additionality criteria leads to minimal total increase of 0.4 GW<sub>el</sub> in installed capacity compared to the base scenario *No Criteria*. The biggest increase can be seen when tightening the temporal correlation from yearly to monthly matching. Adding the strictest RFNBO criteria raises the total installed capacity by approximately 3% compared to *No Criteria*, with a shift to areas with higher offshore wind potential. Moreover, the average full-load hours in Europe decline slightly from ~5300 h with *No Criteria* to ~5100 h with hourly

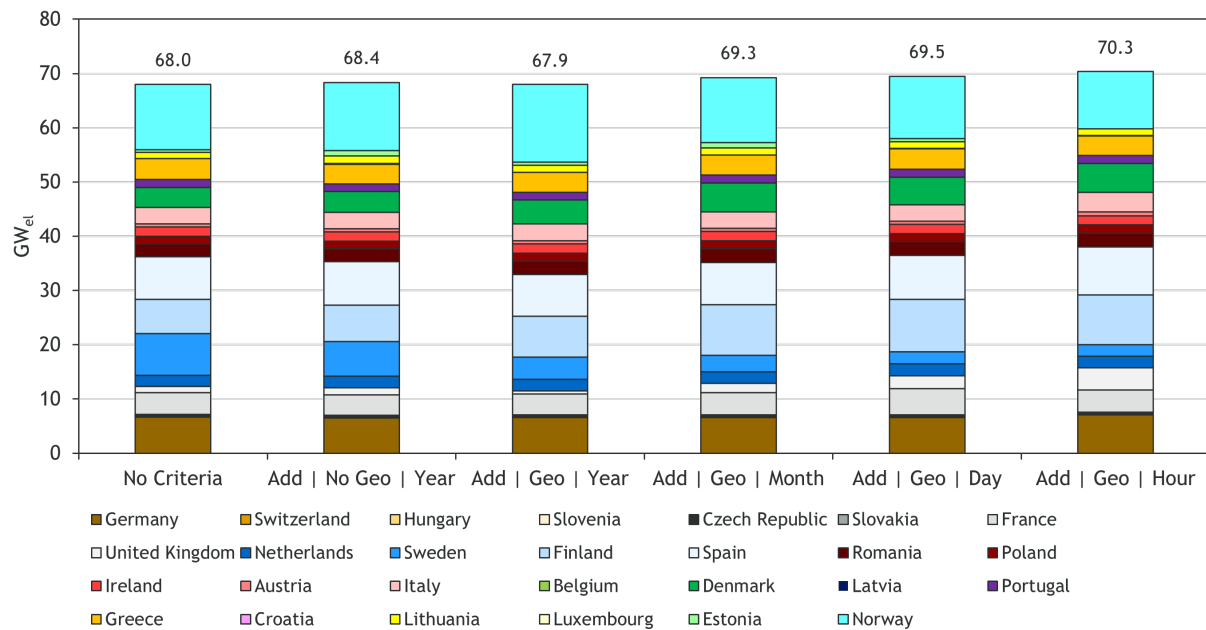


Figure 14: Installed electrolysis capacity by country

Note: Production targets add up to 181 TWh, equaling 78% of the net hydrogen demand in Europe (net demand = green hydrogen demand - imports). The necessary electrolysis capacity as well as the production of the delta between production target and net demand are endogenous model results.

matching, due to the stricter temporal hydrogen production criterion, as hydrogen may only be produced up to the amount of PPA RE production in an hour. However, these results regarding the capacity and the full-load hours are to be viewed under the model's necessary simplifications. No individual nodes or projects are modeled within each country.

Figure 15 shows the change in installed electrolysis capacity by country relative to the *No Criteria* scenario. The geographic distribution of electrolysis capacities remains almost unchanged when only the additionality is complied to (*Add | No Geo | Year*). However, when adding the geographical correlation, capacities shift mainly from Sweden to Norway and to some extent to Finland and Denmark. Adding temporal correlation increases the electrolysis capacity mainly in the UK, Finland, and Denmark while decreasing the capacity in Norway.

Large-scale hydrogen storage can compensate the imbalance of fluctuating production and base-load demand. Hydrogen may be stored in an underground salt cavern or porous storage facilities. Figure 16 shows the resulting hydrogen storage capacity per country and scenario. In all examined scenarios, hydrogen storage potentials in Germany in the reference year are fully utilized. Adding additionality and geographical correlation has almost no effect on the storage capacity across Europe compared to the *No Criteria* scenario. However, the EU-wide demand for hydrogen storage is lowest for a temporal correlation of monthly matching. The demand for storage increases as the temporal correlation becomes stricter, since electrolyzers are required to match RES generation, leading to a more volatile hydrogen production with lower full-load hours of the electrolyzers. Furthermore, hydrogen production from PV can lead to a stronger increase in

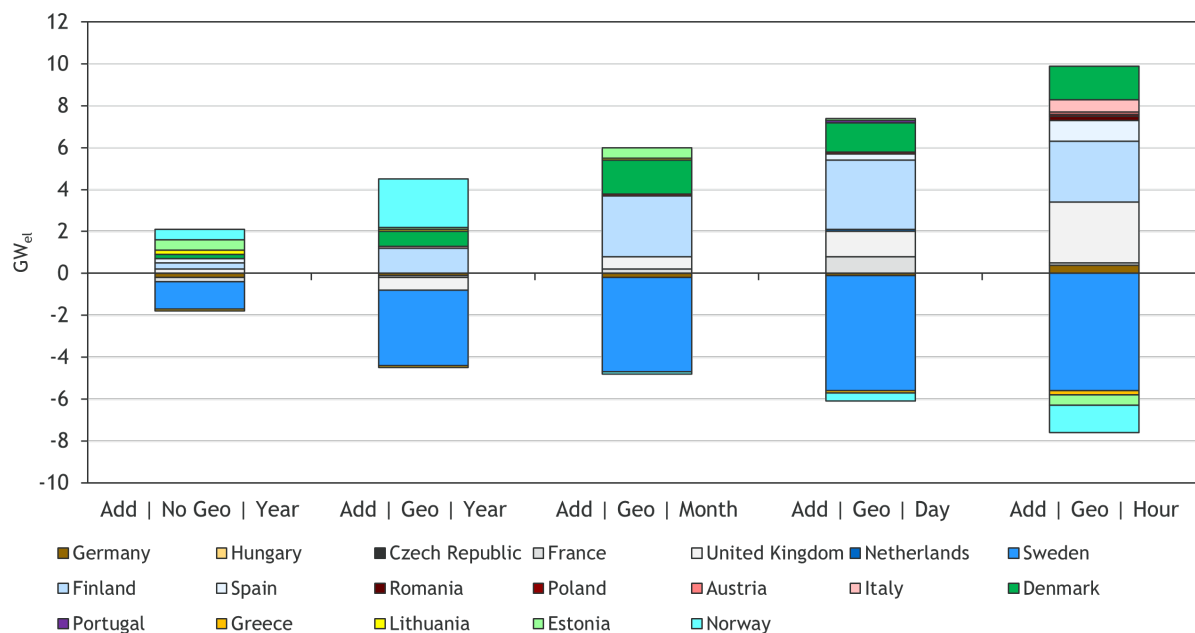
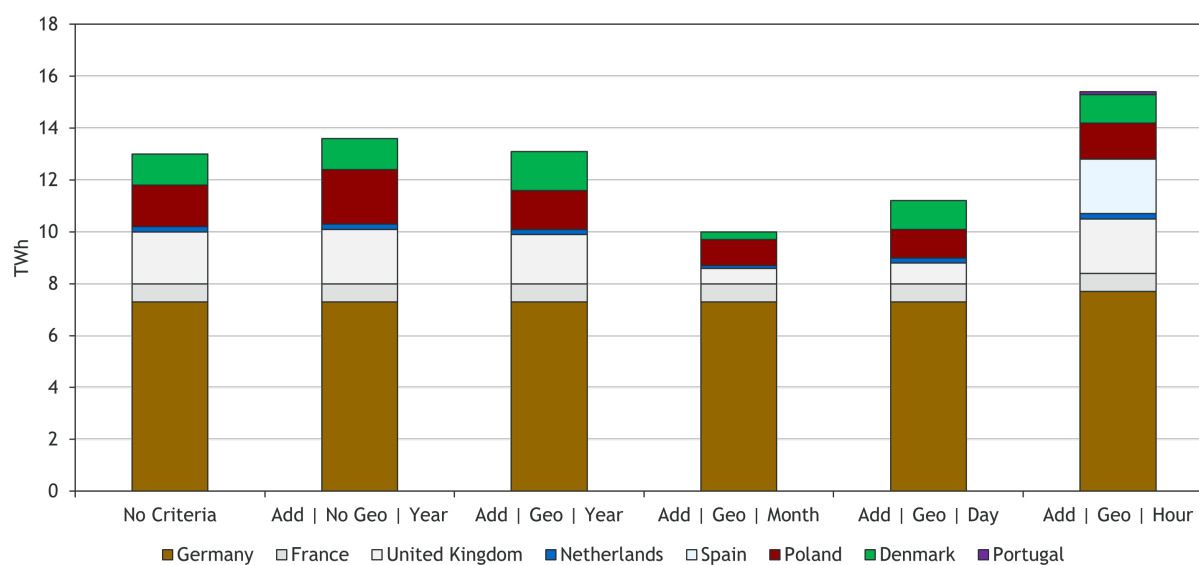
Figure 15: Change in installed electrolysis capacity by country relative to the *No Criteria* scenario

Figure 16: Hydrogen storage capacity per country

storage demand with stricter RFNBO regulation due to the seasonality of PV. In the modeling approach, injection and withdrawal capacities are constrained relative to the storage volume, with the injection capacity typically being the binding constraint. Thus, the required storage volumes are mainly determined by the necessary injection capacities to handle peak surplus generation. While the maximum potential of converted cavern storage is utilized in all scenarios in Germany, in the *Add | Geo | Hour* investments are also made in new cavern storage.

### 2.2.3 Spotlight on Germany

As the previous results show, the impact of RFNBO criteria on total system costs and marginal hydrogen costs in the European energy system lies in the lower double-digit percentage range. However, the results may differ more significantly if disaggregated on a country level. The following subchapter shows the effect of the RFNBO criteria on the marginal hydrogen and electricity costs as well as the capital stock in Germany - a country expected to be the biggest offtaker of hydrogen in Europe.

Figure 17 shows how the marginal hydrogen costs in Germany, representing hydrogen prices in Germany for a mix of imports and domestic production within the framework of an ongoing hydrogen ramp-up with existing international infrastructure and significant demand. For *No Criteria* they show a level of 144 EUR/MWh, which is 14% above the European average. A large increase (+16 EUR/MWh / +11%) may be seen for the *Add | Geo | Year* scenario compared to the scenario without any criteria. The monthly or daily matching has almost no additional impact on the marginal costs. Hourly matching induces a further increase in the marginal costs of hydrogen (+5 EUR/MWh) compared to the *Add | Geo | Day* scenario. The effect of the RFNBO criteria on the marginal costs in Germany is higher than on average in Europe, as wind potentials show less full-load hours and PV has a more seasonal profile in Germany compared to other regions in Europe - both are a poor fit for baseload hydrogen supply. Thus, with tightening criteria, it may become increasingly difficult to meet the exogenous production target in Germany.

Figure 18 shows the marginal electricity costs in Germany. The same pattern of decreasing electricity prices is observed as for the average of Europe (see Figure 10). Nevertheless, the level is slightly higher, starting at 95 EUR/MWh for *No Criteria* and decreasing slightly to 92 EUR/MWh for the *Add | Geo | Hour* scenario.

The installed capacities of renewable energies in Germany in Figure 19 show that with Additivity but without geographical or temporal correlation (*Add | Geo | Year* scenario), German electrolyzers take up PPAs with cost-effective solar power plants in the south of Europe. When the geographical correlation is added, the PPAs capacities shift to offshore wind in Germany with high full-load hours. At the same time, significant solar power has to be built in Germany to reach the targeted RES share in the electricity market. However, once the temporal correlation is tightened to monthly matching, solar power for hydrogen production becomes relevant in Germany as well. Total RES capacity in Germany increases from 236 GW<sub>el</sub> without the criteria to 277 GW<sub>el</sub> with all criteria. All additional capacity is attributable to solar power, as the sums of wind

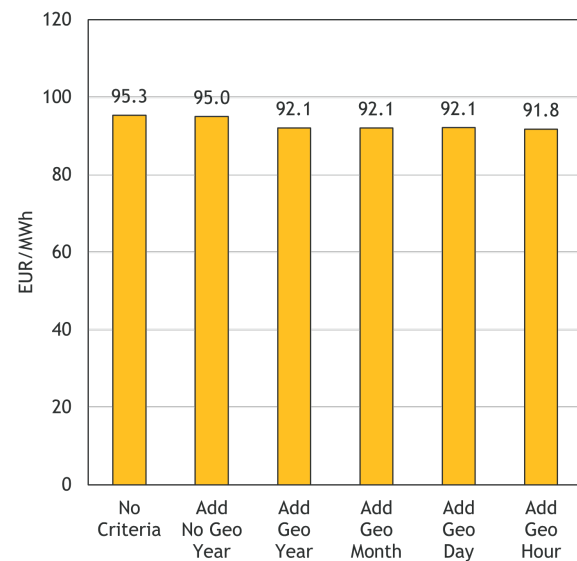
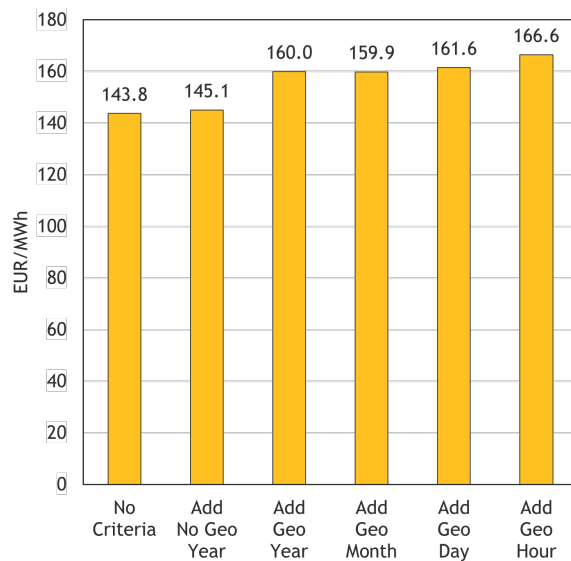


Figure 17: Marginal hydrogen costs in Germany    Figure 18: Marginal electricity costs in Germany

offshore and wind onshore capacities stay constant throughout the scenarios. This corresponds to the exogenously given upper limits for the RES expansion.

Germany has a hydrogen demand of 78 TWh and a production target of 30 TWh in this analysis. The hydrogen production stays constant in all scenarios and equals the exogenous lower limit of the hydrogen production target. No additional hydrogen above this target is produced in Germany. The rest of the demand is covered with imports via almost all neighboring countries. Figure 20 shows that electrolyzer capacity thus varies only slightly between 6.5 GW<sub>el</sub> and 7.1 GW<sub>el</sub> for the different scenarios due to varying full-load hours. Full load hours of the German electrolyzers are slightly above 6000 h in the scenarios with additionality but slightly lower than 6000 h for no criteria and all criteria.

The analysis of Germany shows that the RFNBO criteria may have a higher impact on the energy system in countries without abundant RES potentials but with high production targets, compared to the average of Europe. Additionally, this analysis shows that the results are significantly influenced by exogenously given restrictions or targets that correlate to current political goals.

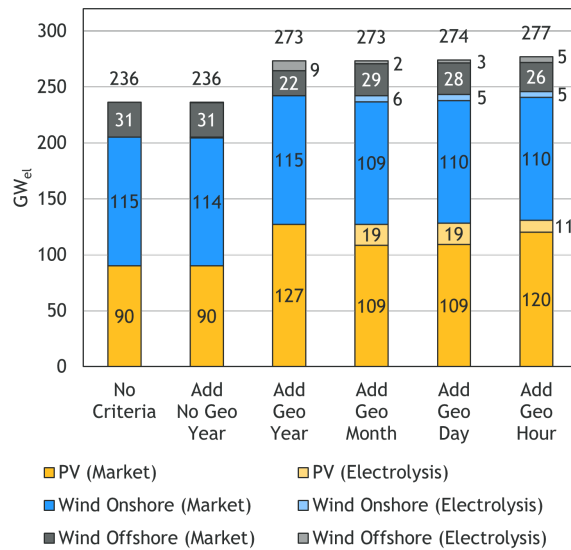


Figure 19: Installed capacities of renewable energies in Germany

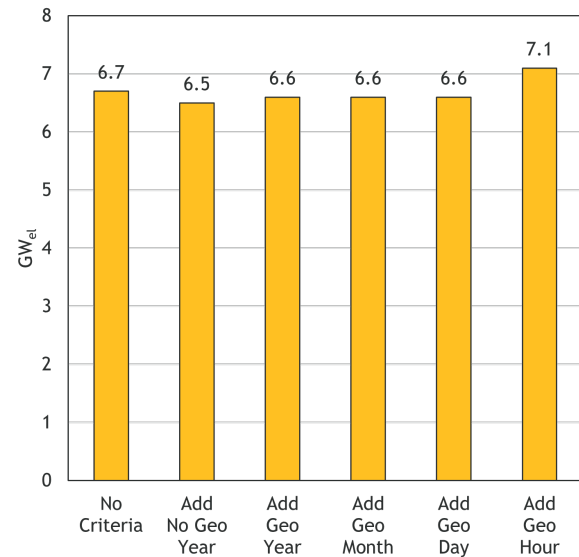


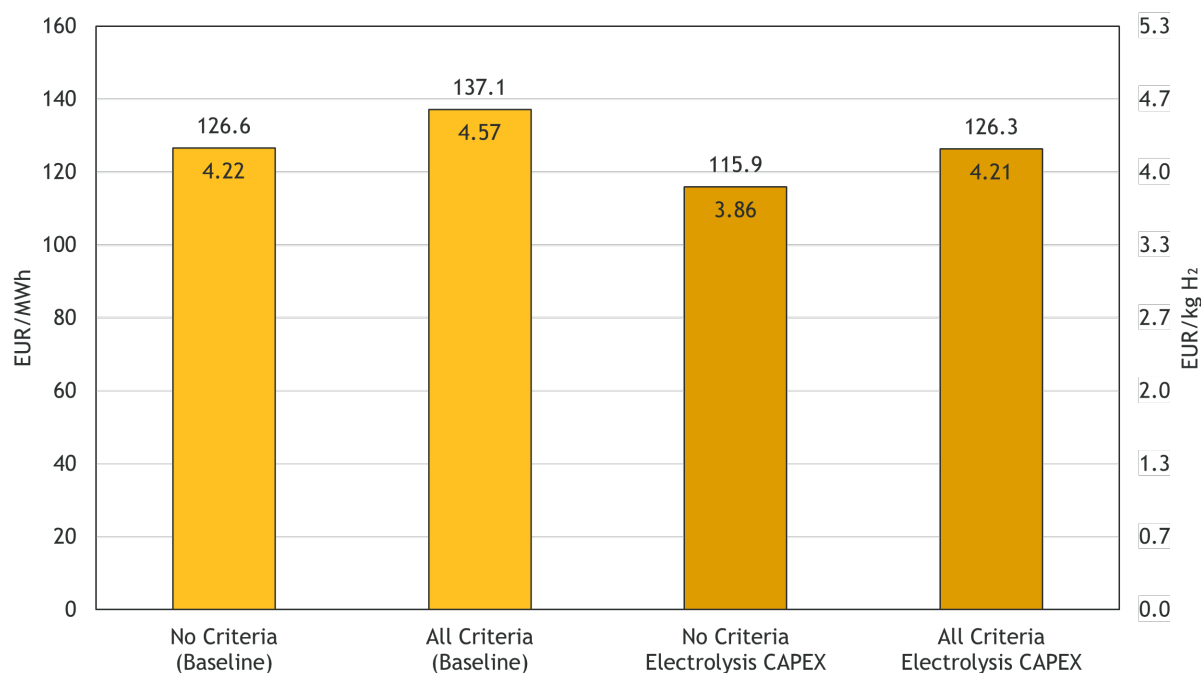
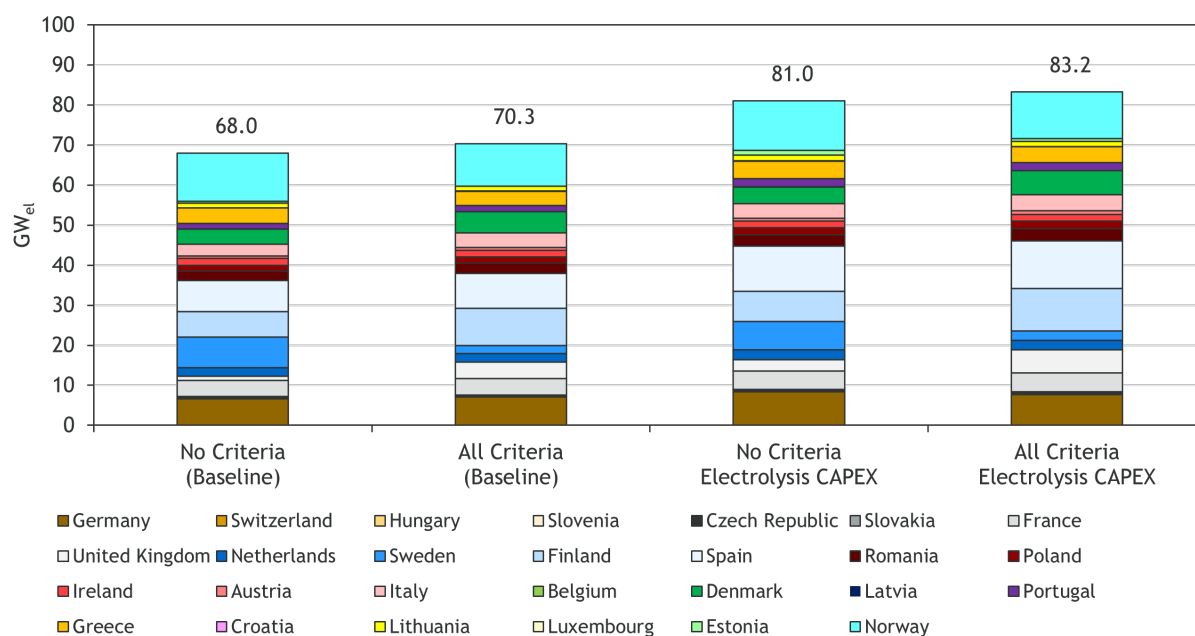
Figure 20: Installed electrolysis capacity in Germany

### 2.2.4 Sensitivity Results

Four sensitivities are analyzed to enable a differentiated assessment of how certain assumptions like technology costs, import dependency, storage availability and production targets influence the interaction of the European energy system under the RFNBO criteria. Each sensitivity is modeled for the base scenarios *No Criteria* and *Add | Geo | Hour* (referred to as *All criteria* in the following chapter).

**Electrolysis CAPEX** Investment costs for electrolysis are a significant driver of hydrogen costs and subject to uncertainty, especially regarding scaling and learning effects. Lower investment costs may lead to a more volatile hydrogen production with lower full-load hours. In this context, system costs and hydrogen supply costs decrease as investment costs for electrolyzers decline. Figure 21 shows that a decrease in electrolyzer CAPEX leads to a reduction of marginal hydrogen costs. However, the effect of the RFNBO criteria remains unchanged, as *All Criteria* lead to an increase in marginal hydrogen costs of around 9% in the Electrolysis CAPEX sensitivity.

Regarding installed electrolysis across Europe, lower investment costs lead to higher installed capacities and, consequently, lower full-load hours (FLH). In this sensitivity, FLH range between approx. 5200 h for *No Criteria* and 4800 h for *All criteria*. Figure 22 indicates that the installed electrolysis capacity increases by around 19% with lower investment costs. The regional distribution remains largely unchanged regardless of the cost decrease and the introduction of the RFNBO criteria. Overall, the electrolyzer investment costs have little influence on the impact of the RFNBO criteria.

Figure 21: Average marginal cost of hydrogen in Europe in the sensitivity *Electrolysis CAPEX*Figure 22: Installed electrolysis capacity per country in the sensitivity *Electrolysis CAPEX*

**Non-European Imports** The base scenario assumes that a significant amount of the hydrogen demand is covered by non-European imports (38%). In the sensitivity with limited overseas supplies, exogenous hydrogen imports are reduced by 50%. Figure 23 shows that the marginal cost of hydrogen produced in Europe increases slightly by less than 2 EUR/MWh, as less favourable production potentials must be used to cover the remaining demand. However, the effect of the RFNBO criteria decreases in this sensitivity as those less favourable potentials would also be used for production under the RFNBO criteria, where the marginal cost of hydrogen produced decreases very slightly.

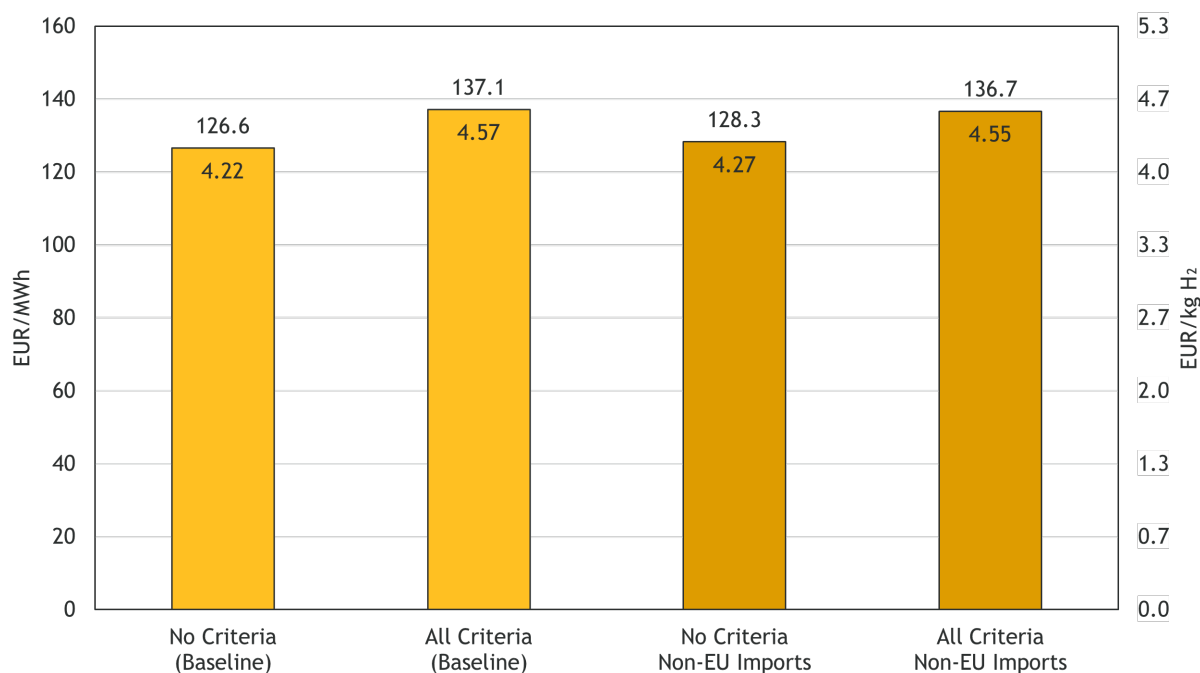


Figure 23: Average marginal cost of hydrogen in Europe in the sensitivity *Non-European imports*

Examining installed electrolysis per country under the scenario of non-European imports, European production has to increase significantly. Figure 24 shows that electrolysis capacity increases by 26% without criteria and 27% with all RFNBO criteria, while full-load hours also increase slightly. Furthermore, the regional distribution across Europe indicates that the increase in electrolysis capacity affects mostly France, UK, Finland, and Denmark. Hydrogen production in countries like Germany, the Netherlands and Italy still does not exceed the production targets. With the introduction of the RFNBO criteria, even greater emphasis is placed on the production in the UK, Finland, and Denmark.

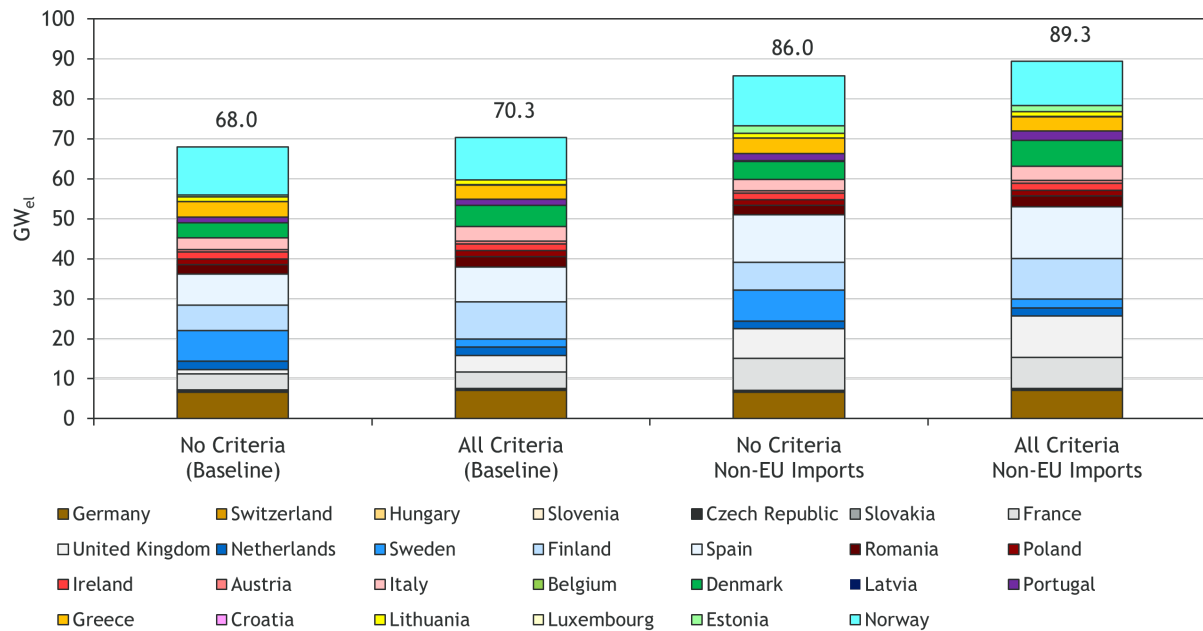
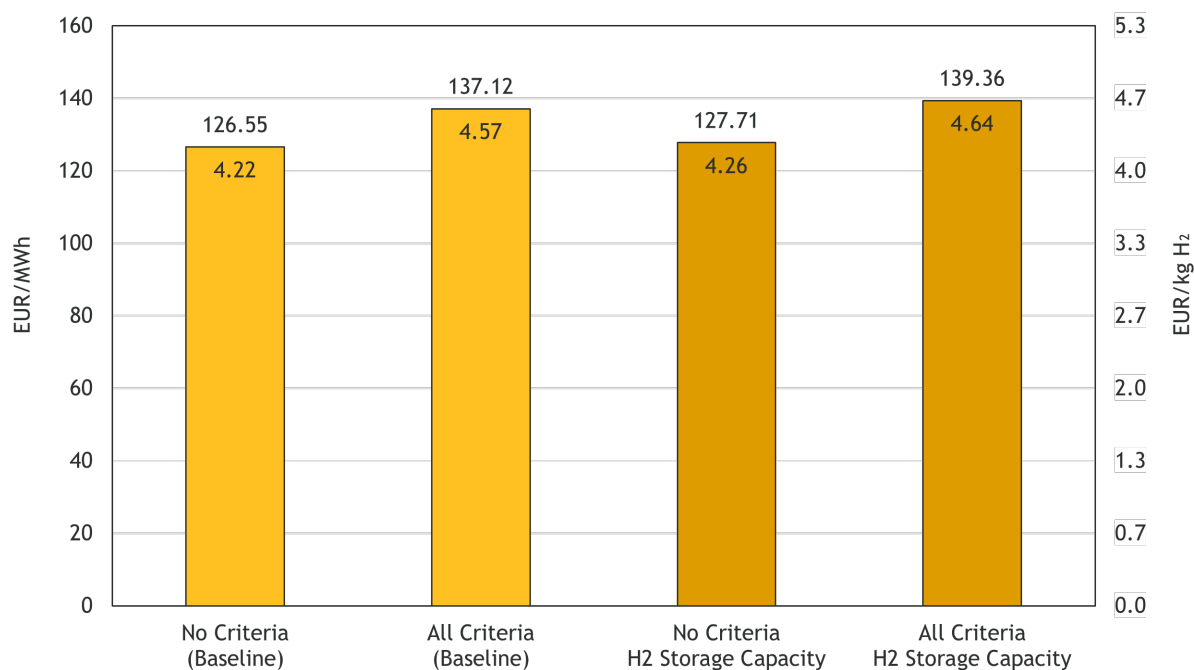
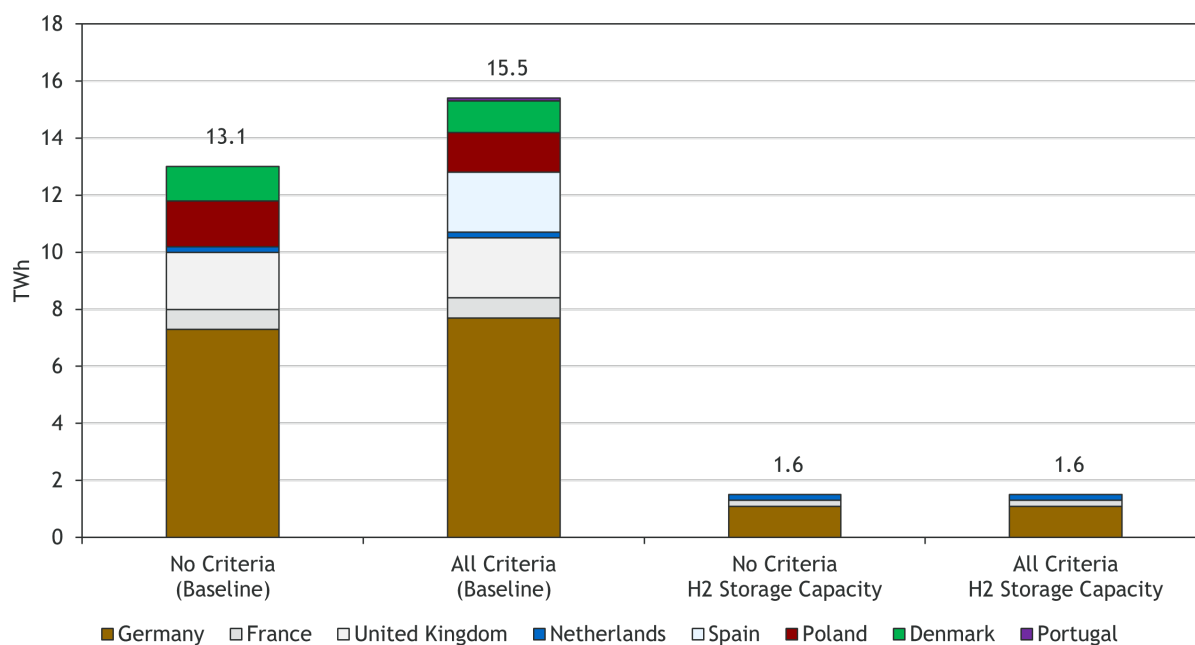


Figure 24: Installed electrolysis capacity per country in the sensitivity *Non-European imports*

**H<sub>2</sub> storage capacity** In this sensitivity, only hydrogen storage projects that currently have a final investment decision (FID) can be realized. This significantly reduces the available hydrogen storage capacity to 1.6 TWh in both the *No Criteria* and *All criteria* scenarios (Figure 26). Out of this total capacity, Germany accounts for 1.1 TWh, and the remainder is located in France and the Netherlands. While the available storage potential is fully utilized in Germany and France, storage capacity is also built in the Netherlands, although not up to its maximum available potential. Despite available potential, no hydrogen storage is built in Spain or Denmark in this sensitivity. The decrease and shift in storage capacity has only minor impact on the marginal cost of hydrogen, leading to an increase of 1.1 EUR/MWh without RFNBO criteria and 2.3 EUR/MWh with full implementation of RFNBO criteria. Examining installed electrolysis per country, the limitation of hydrogen storage capacities has minimal effect on the total capacities and the regional distribution of electrolyzers.

Figure 25: Average marginal cost of hydrogen in Europe in the sensitivity  $H_2$  storage capacityFigure 26: Hydrogen storage capacity per country in the sensitivity  $H_2$  storage capacity

**No H<sub>2</sub> production targets** In the sensitivity *No H<sub>2</sub> production targets*, the production targets according to current political targets of electrolysis capacity expansion are disregarded. Hydrogen transport is still limited by exogenously given pipeline capacities throughout Europe. As depicted in Figure 28 in the case of *No Criteria* a significant decrease of around 6 EUR/MWh in the marginal cost of hydrogen may be seen due to the freedom to place electrolyzer capacities and production towards cheaper renewable energy potentials. For the case of *All criteria*, the cost decrease by 9 EUR/MWh on average in Europe compared to the base scenario. Additionally, the difference between *No Criteria* and *All criteria* is smaller without the production targets. Consequently, from a system point of view, the differently distributed hydrogen production may lower marginal costs and the effects of the RFNBO criteria.

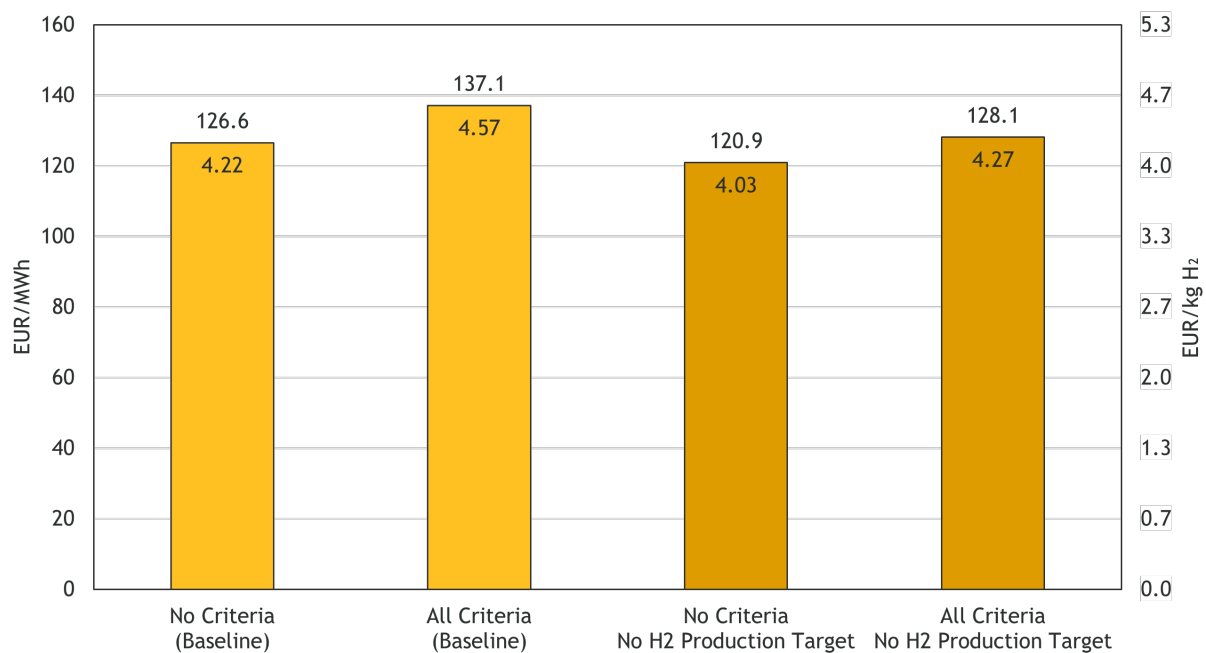


Figure 27: Average marginal cost of hydrogen in Europe in the sensitivity *No H<sub>2</sub> production targets*

Figure 28 shows the installed electrolysis capacity per country in the sensitivity. If current hydrogen production targets are disregarded, hydrogen production is significantly more concentrated in individual countries across Europe. Germany, Hungary, the Czech Republic, Austria and Italy show no electrolysis capacity in this sensitivity, while the UK, Spain, Estonia and Finland see a significant increase compared to the base scenario. The influence of the RFNBO criteria is higher in this sensitivity, as total capacity increases by 3.8 GW<sub>el</sub> (6%). The RFNBO criteria also lead to a significant change in the regional distribution, as capacities shift from France and Sweden to the UK, Finland and Denmark.

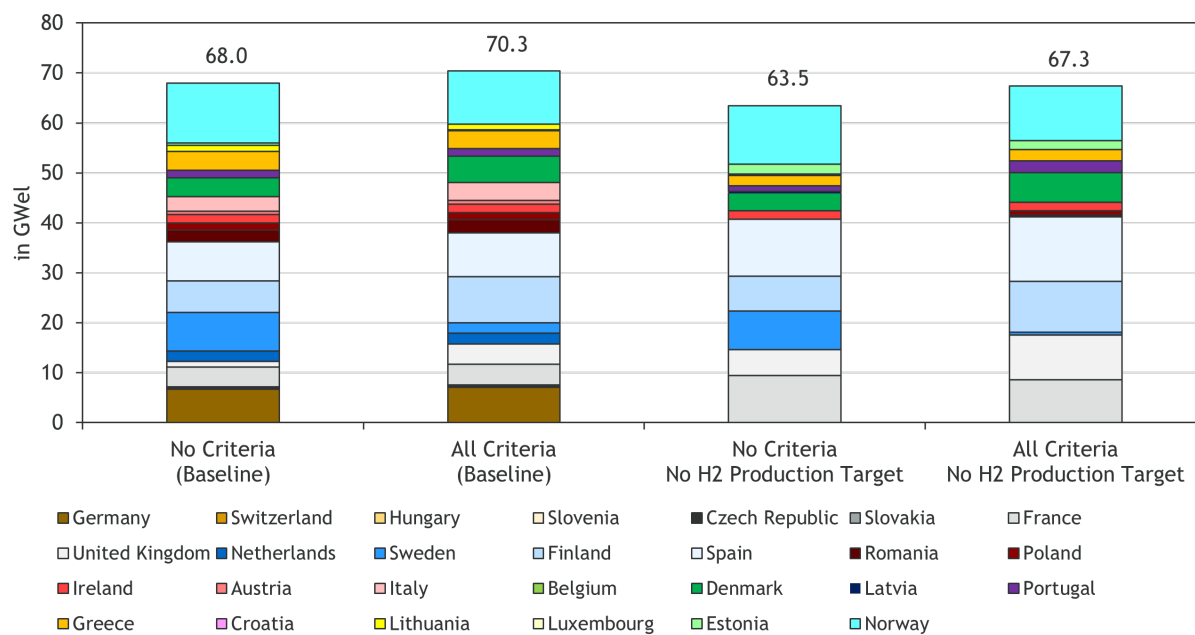


Figure 28: Installed electrolysis capacity per country in the sensitivity *No H<sub>2</sub> production targets*

## 3 Business Perspective on RFNBO Criteria for Hydrogen Production

The previous section assessed system-wise cost and capacity effects of the RFNBO criteria. While that approach ensures analysis of interdependencies between hydrogen production and the electricity market, it may not represent all challenges of project-level economics. Thus, this section examines the implications of the RFNBO criteria from a business case perspective. Section 3.1 outlines the methodological approach, while Section 3.2 introduces the results.

### 3.1 Methodology for the Business Case Analysis

From a business perspective, the design of a hydrogen production system under RFNBO criteria requires determining the sizing of multiple system components. The decisions involve the relative sizing of electrolyzers, power purchase agreement (PPA) portfolios and storage options (both batteries and hydrogen). Identifying the appropriate sizing of these components is best achieved through an optimization approach. Accordingly, this analysis employs an optimization model to (i) determine the cost-optimal configuration of the hydrogen production system, (ii) optimize operational decisions (including electricity purchases from and sales to the wholesale market) and finally (iii) assess the implications of the restrictions imposed by the RFNBO criteria. The following subsection introduces the model framework, describes the underlying data, and outlines the set of examined cases and sensitivities.

#### 3.1.1 The Model SOPHIAA and the Data employed

The SOPHIAA model<sup>6</sup>, developed at EWI, captures the business-oriented decision-making process for hydrogen production. It is a stochastic linear optimization model that minimizes the levelized cost of hydrogen (LCOH) by determining the optimal sizing and operation of key system components, including electrolyzers, storage facilities (both batteries and hydrogen), and power purchase agreement (PPA) portfolios<sup>7</sup>. In addition to sizing, SOPHIAA optimizes the operation of these components over an entire calendar year, allowing hydrogen production to be either volatile or baseload or a mixture of the two. Electricity purchases from and sales to the grid are optimally scheduled, capturing trade-offs between cost, production flexibility, and compliance with RFNBO criteria. The producer represented in SOPHIAA is acting as a price taker in the electricity markets. Therefore, the electrolyzer's demand is assumed not to influence market prices. A schematic representation of SOPHIAA can be found in Figure 29.

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<sup>6</sup>Stochastic Optimization for Producing Hydrogen and Investment in Associated Assets (SOPHIAA)

<sup>7</sup>In SOPHIAA, stochasticity is introduced through multiple historical weather years. However, this analysis is limited to one (weather) year (2024) due to the availability of historical wholesale electricity prices.

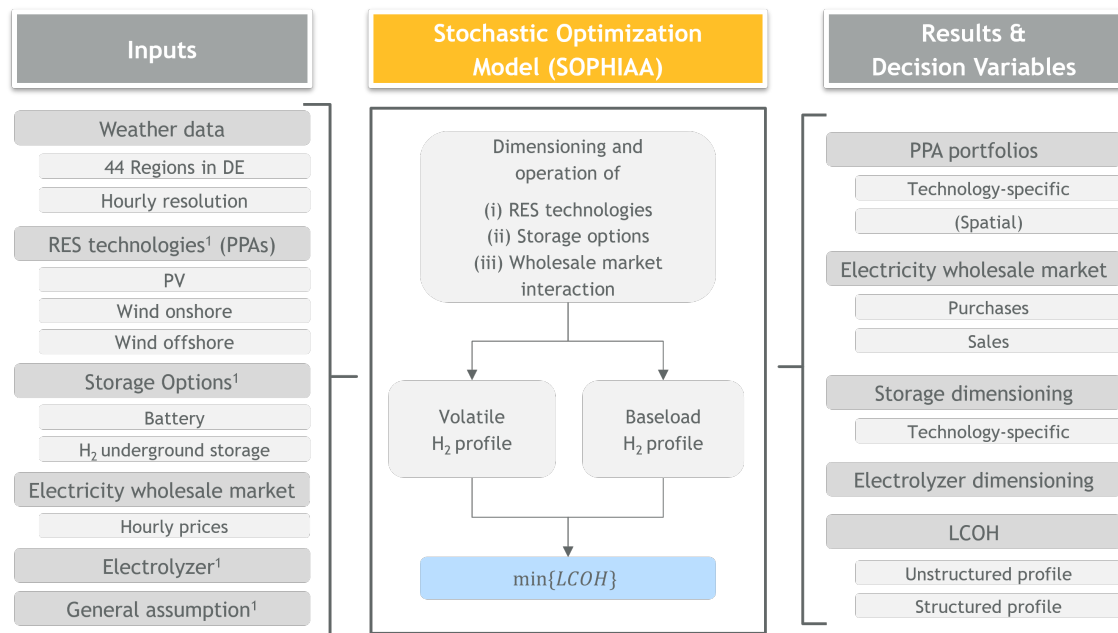


Figure 29: Schematic representation of SOPHIAA

1 | Sources: EWI (2024) and EWI (2025)

SOPHIAA integrates a wide range of input parameters: historic weather year data in hourly resolution for 44 regions in Germany, renewable energy technologies (ground-mounted PV, onshore wind, offshore wind), various storage options (batteries as well as repurposed underground hydrogen storage), and technology assumptions for electrolyzers (see Section 2.1.2). For each historical weather year, the corresponding historical electricity price time series is incorporated. The historical electricity prices are both employed for computing PPA prices and for representing wholesale market purchases and sales in the optimization. The PPA prices are regionally differentiated and computed as market values using historic hourly technology-specific availabilities and electricity prices. The price ranges and averages (across all regions) are presented in Table 4. The resulting asset size forms the basis for calculating the respective production costs. Whereas the system perspective analysis (Section 2) primarily focuses on a future energy system where the hydrogen market and infrastructure ramp-up is underway, the business analysis is performed for current market conditions. Consequently, assumptions for parameters such as electrolyzer and RES investment costs differ in the business perspective, as future cost degression is expected to advance in the coming years.

Table 4: PPA Price Assumptions based on site-specific market values

|         | PV   | Wind Onshore | Wind Offshore | Unit    |
|---------|------|--------------|---------------|---------|
| Min     | 64.2 | 76.1         | 78.8          | EUR/MWh |
| Max     | 69.8 | 79.8         | 80.0          | EUR/MWh |
| Average | 66.3 | 77.5         | 79.5          | EUR/MWh |

Source: Own calculation based on historical wholesale electricity prices and hourly availability of each renewable technology and geographical region.

The model explicitly accounts for the RFNBO criteria of the RED II Directive, with a focus on temporal correlation. Temporal correlation is enforced by ensuring that, over a defined time period, the electricity generated from contracted PPAs – either directly or via battery storage – matches the electricity consumed in hydrogen production. As PPAs are restricted to domestic procurement, the geographical correlation requirement is always satisfied. Additionality is incorporated by assuming PPA prices that reflect the current market value of electricity from newly built renewable energy assets.

Finally, the SOPHIAA model operates under the assumption of perfect foresight. Forecast errors, both regarding the RES availability and the electricity wholesale price, are not considered. Thereby, the model can perfectly schedule electrolyzer operation, drawing on low-cost grid electricity while anticipating that future PPA generation will be sufficient to satisfy the temporal correlation requirement. As a result, the costs of mitigating risks of non-compliance with RFNBO criteria are underestimated, implying that the resulting LCOH represents a lower-bound estimate. Furthermore, the model implicitly assumes abundant availability of PPA contracts at each location, thereby abstracting from real-world frictions such as transaction costs, portfolio management expenses, and limited PPA availability. As the share of RES electricity in the grid increases, the mechanisms and levels of price formation in wholesale markets are likely to change. This analysis is intentionally conducted under current market conditions. A projection into the future would require a fundamental modeling of electricity prices within a future energy system.

### 3.1.2 Baseline Configuration and Sensitivities

For the purposes of this analysis, a baseline configuration is defined. This baseline is evaluated for a reference case of *No Criteria* and across four levels of temporal correlation: *Annual*, *Monthly*, *Daily*, and *Hourly Matching*. In the *No Criteria* case, the producer is free to decide on electricity procurement (i.e., via wholesale market and or PPAs) and the use of battery storage. The analysis is based on the historical weather and market data of the year 2024. The baseline configuration is composed as follows:

- **Storage options:** The model has the opportunity to augment its PPA portfolio with a battery storage, allowing surplus electricity to be shifted in time. The optimal storage capacity is a result of the modelling. Hydrogen storage options are evaluated in a sensitivity analysis.
- **Electricity trading:** The primary objective of the modeled agent is hydrogen production. To simulate market uncertainty and to prevent the agent from effectively acting as an electricity trader, electricity sales to the grid are restricted. Specifically, the net difference between electricity sales and purchases from the grid may not exceed 20% of the total electricity consumed for hydrogen production. This share is varied in the sensitivity analysis.

- **Supply profile:** The hydrogen supply profile is required to be 50% baseload, meaning that half of the annual production target must be delivered evenly over all 8,760 hours of the year. The remaining 50% can be distributed optimally by the optimization model. During an early ramp-up stage, hydrogen offtakers may be somewhat flexible, allowing periods of low production to be supplemented with hydrogen from alternative origin.

To evaluate the effects of deviations from the baseline configuration, a sensitivity analysis has been conducted as part of this report. While the baseline configuration was assessed across five levels of temporal matching, each sensitivity analysis is limited to *Hourly* and *Monthly Matching*. As part of this analysis variations along three dimensions have been investigated: Storage technologies, electricity trading limit and production profile. In the storage sensitivity, a case without battery storage was examined. Secondly, the electricity trading limit assumed in the baseline configuration was varied from 0% up to 40%. Lastly, the baseload requirement was increased to 100%, implying that the annual production target is evenly distributed across all 8,760 hours of the year. Hydrogen storage was only modeled with a 100% baseload requirement. Table 5 lists the baseline configuration as well as all sensitivities performed as part of this research report.

Table 5: Baseline configuration and sensitivity analysis setups

| No. | Description                     | Storage            | Electricity Trading | Supply Profile |
|-----|---------------------------------|--------------------|---------------------|----------------|
| 0   | Baseline Configuration          | Battery            | 20%                 | 50% Baseload   |
| 1   | No Battery                      | -                  | 20%                 | 50% Baseload   |
| 2   | 2.1 No Elec Trade               | Battery            | 0%                  | 50% Baseload   |
|     | 2.2. Enhanced Elec Trade        | Battery            | 40%                 | 50% Baseload   |
| 3   | 3.1 Volatile                    | Battery            | 20%                 | 0% Baseload    |
|     | 3.2 Baseload                    | Battery            | 20%                 | 100% Baseload  |
| 4   | 4.1 Hydrogen Storage            | Battery & Hydrogen | 20%                 | 50% Baseload   |
|     | 4.2 Baseload & Hydrogen Storage | Battery & Hydrogen | 20%                 | 100% Baseload  |

### 3.2 Results: LCOH and Optimal Asset Portfolios

This section presents the results of the business perspective analysis. It highlights how the implementation of different levels of temporal correlation under the RFNBO criteria affects the levelized cost of hydrogen (LCOH) and the optimal sizing of system components. The analysis first discusses the outcomes of the baseline configuration, followed by a set of sensitivity analyses that explore the influence of varying assumptions regarding storage availability, electricity trading and production profiles.

### 3.2.1 Baseline Results

The baseline analysis quantifies how increasingly strict temporal correlation requirements affect the levelized cost of hydrogen (LCOH), the composition of the electricity supply portfolio and the use of flexibility options. Figure 30 shows a diagram of the cost components that add up to the LCOH in the scenario *No Criteria*. The LCOH add up to 149 EUR/MWh. Cost components include the CAPEX and FOM of the electrolyzer, the PPA with renewable energy power plants, the CAPEX and FOM of the battery as well as the costs for purchasing electricity on the wholesale market and the revenue of selling excess electricity of the PPAs.

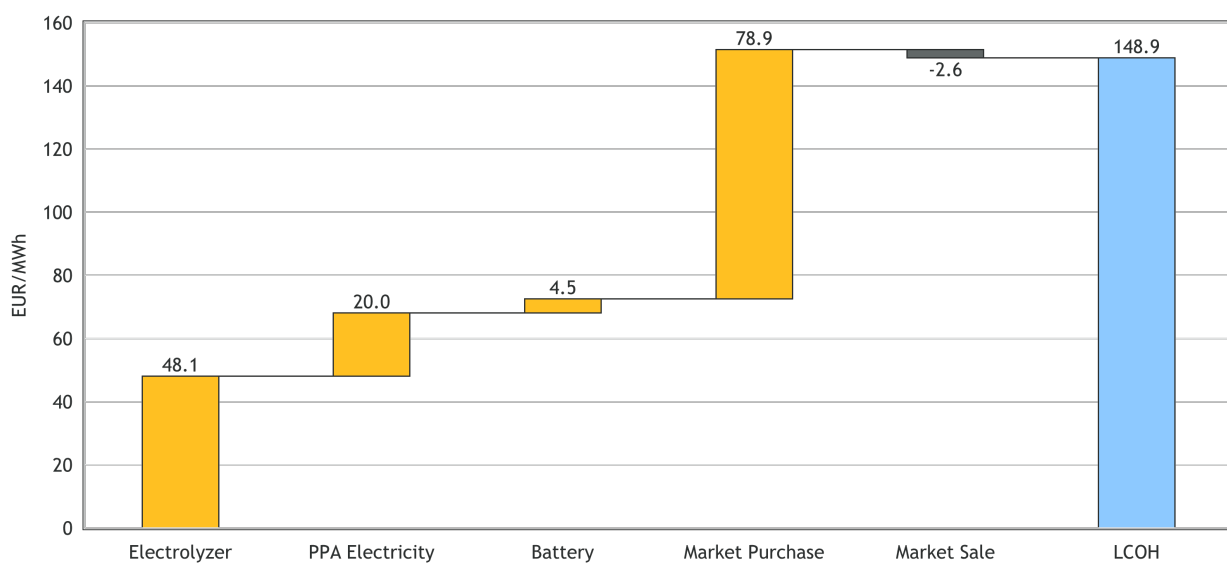


Figure 30: Cost composition of hydrogen production without RFNBO criteria

In the *No Criteria* case, electrolyzers can freely source electricity from the wholesale electricity market without any restrictions regarding additionality or temporal correlation. As a result, the operator relies on a mix of market electricity and power purchase agreements (PPAs), with the majority of hydrogen production covered by market purchases. PPAs serving primarily as a supplementary, cost-stabilizing source of renewable electricity. Revenues from electricity sales to the market are negligible, as surplus generation rarely occurs. Consequently, the largest share of the LCOH originates from market purchases, making this configuration strongly dependent on wholesale electricity price dynamics.

In the *Monthly Matching* case, shown in Figure 31, the hydrogen producer must ensure that the renewable electricity generation from contracted PPAs covers the electricity consumption of the electrolyzer in each month. This requirement limits flexibility compared to the *No Criteria* case, yet still allows for temporal balancing within a month. While the resulting increase in LCOH remains moderate compared to the *No Criteria* case (+5%), the cost composition changes substantially. The share of PPA electricity in total consumption rises sharply, whereas grid purchases play only a minor role. The stronger reliance on renewable generation also leads to a significant amount of surplus electricity, which can be sold on the wholesale market. As noted

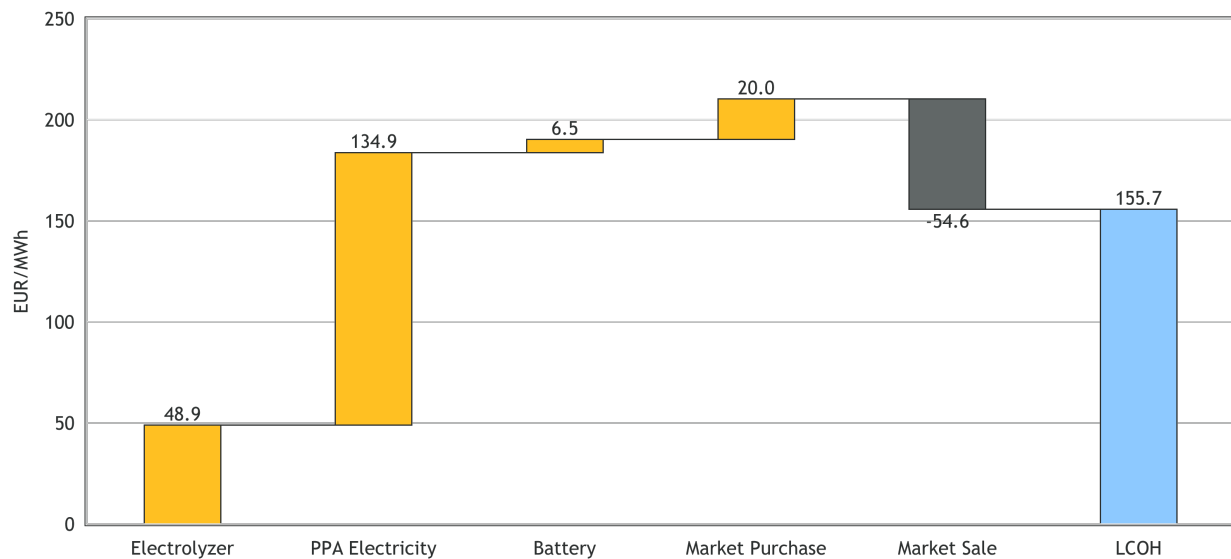


Figure 31: Cost composition of hydrogen production under *Monthly Matching*

above, surplus trading, i.e., the net difference between electricity sold to and purchased from the market, is capped at 20% of the electricity used for hydrogen production in the baseline configuration. The opportunity for surplus trading is extensively utilized and reduces the LCOH by more than 50 EUR/MWh, partially offsetting the higher costs of renewable electricity and battery operation.

In the *Hourly Matching* case, electricity consumption for hydrogen production must match renewable generation from PPAs in every single hour. This requirement removes almost all operational flexibility and enforces a tight alignment between renewable generation and electrolyzer operation. Market purchases are not allowed, but excess electricity can be sold to the market (see Figure 32). The resulting LCOH rises to 178 EUR/MWh, +14% compared to *Monthly Matching*. This increase is primarily driven by higher costs for PPA electricity and the need for additional battery capacity to balance hourly fluctuations. Unlike in the *Monthly Matching* case, surplus electricity can be marketed less effectively; instead, a growing share must be stored and re-used to maintain compliance during periods of low renewable generation. Consequently, revenues from market sales decrease, while the costs associated with storage and PPAs increase substantially. The overall cost structure shifts towards a system dominated by renewable generation and storage.

Figure 33 shows the resulting LCOH for all matching steps in the baseline configuration. The LCOH rises from 149 EUR/MWh in the *No Criteria* case to 178 EUR/MWh under *Hourly Matching*. Intermediate matching levels show only moderate increases to 153 EUR/MWh (annual), 156 EUR/MWh (monthly), and 160 EUR/MWh (daily). The cost difference between *Daily Matching* and *Hourly Matching*, however, is notably larger than between the other steps, indicating that the transition to *Hourly Matching* imposes a disproportionate increase in costs. This reflects the fact that intraday fluctuations of RES generation (especially PV) are far more pronounced than day-to-day variability: meeting an hourly balance leaves little room to offset shortfalls within the day,

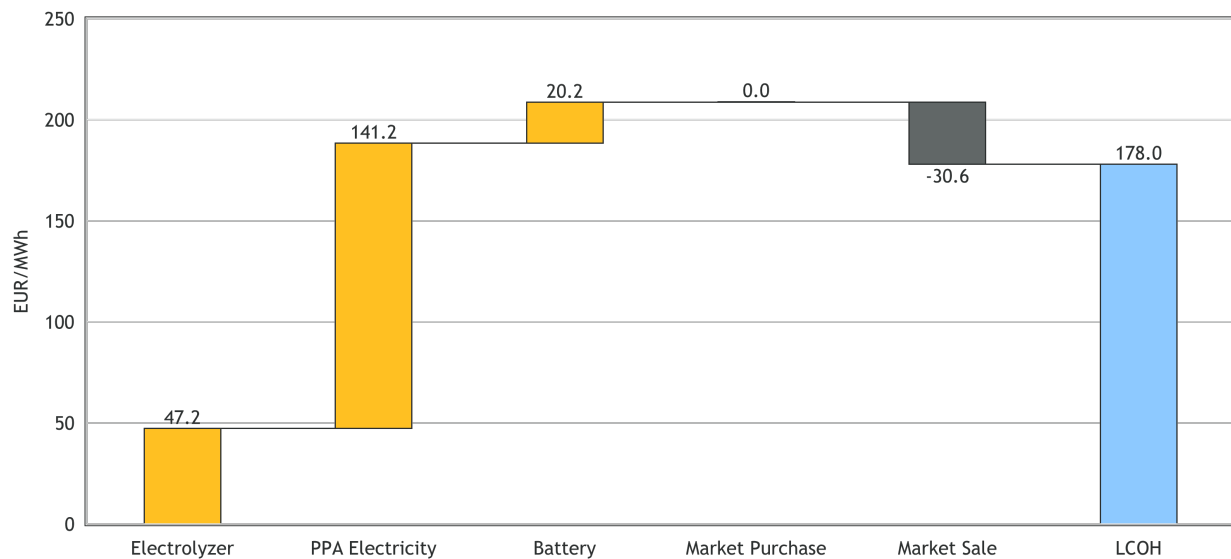


Figure 32: Cost composition of hydrogen production under *Hourly Matching*

which raises storage needs and decreases asset utilization, whereas a daily window still allows smoothing across hours of the same day.

Compared to the system perspective, absolute LCOH levels are higher, as the business perspective does not capture system-wide coordination effects or synergies across regions and sectors. At the same time, the cost impact of stricter temporal correlation requirements is more pronounced here, illustrating that individual projects are more exposed to the implications of the RFNBO criteria. Nevertheless, the overall trend is consistent across both perspectives: stricter temporal correlation increases hydrogen production costs, with the most significant step between daily and *Hourly Matching*.

The effect of the RFNBO criteria on renewable generation portfolios and electricity flows is illustrated in Figures 34 and 35. The assets are sized to meet an annual hydrogen demand of 100 GWh; as a model outcome, the electrolyzer power capacity is about 21 MW<sub>el</sub> across all baseline configurations. Without any criteria, only a small amount of dedicated renewable capacity is built (around 13 MW<sub>el</sub> of generation and 9 MW<sub>el</sub> of battery storage) while the majority of electricity is purchased directly from the wholesale market.

Technology choices reflect a trade-off between cost and profile rather than solely full-load hours (FLH): PV is cheaper but more variable, while offshore wind is costlier, yet has very high full-load hours. In the modeling approach, it is assumed that the PPA is paid per MWh (market value of the unit produced) rather than per unit of capacity. Once *Annual Matching* is introduced, the system shifts almost entirely to onshore wind, with no PV capacity installed. The amount of electricity sold to the grid equals the electricity drawn from it, indicating that no net surplus is marketed. Under *Annual Matching*, the PPA portfolio consists of sites in low-wind-regions despite lower FLH (1,100 h), since they are assumed to have a lower PPA price.

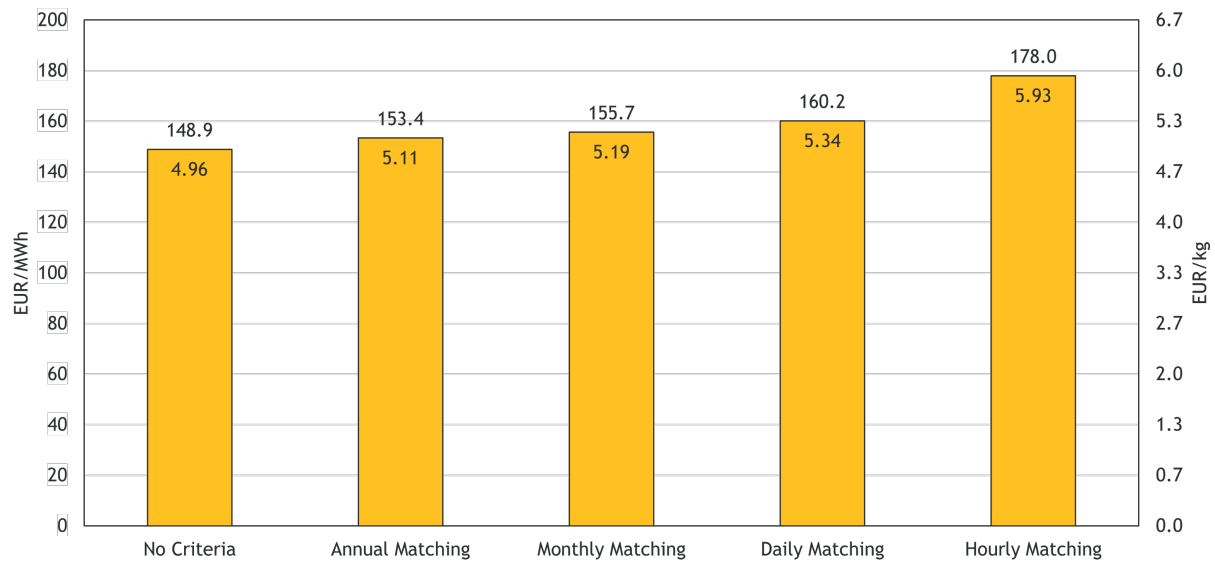


Figure 33: Levelized cost of hydrogen under different temporal correlation requirements

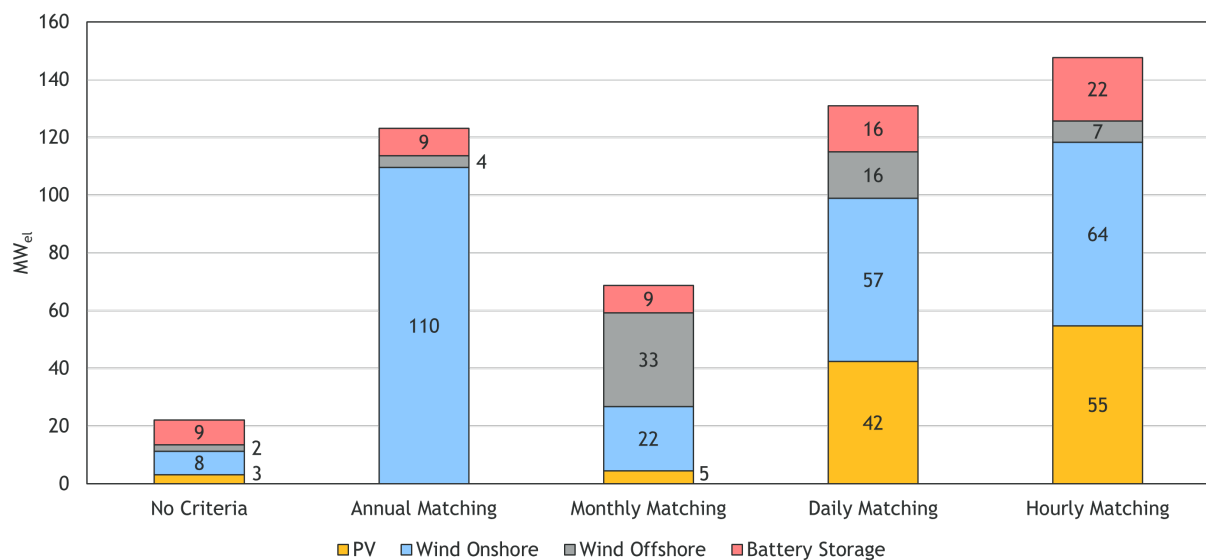


Figure 34: Installed PPA capacities by technology and temporal correlation requirement

Under *Monthly Matching*, the total installed PPA capacity decreases compared to the annual case; however, the inclusion of offshore wind with higher full-load hours leads to a greater overall electricity output from PPAs. As the temporal requirements tighten further, the portfolio composition diversifies: stricter temporal correlation criteria increasingly favor PV generation and require larger battery capacities. This combination enables short-term balancing of fluctuating renewable generation and ensures continuous compliance with *Hourly Matching* constraints.

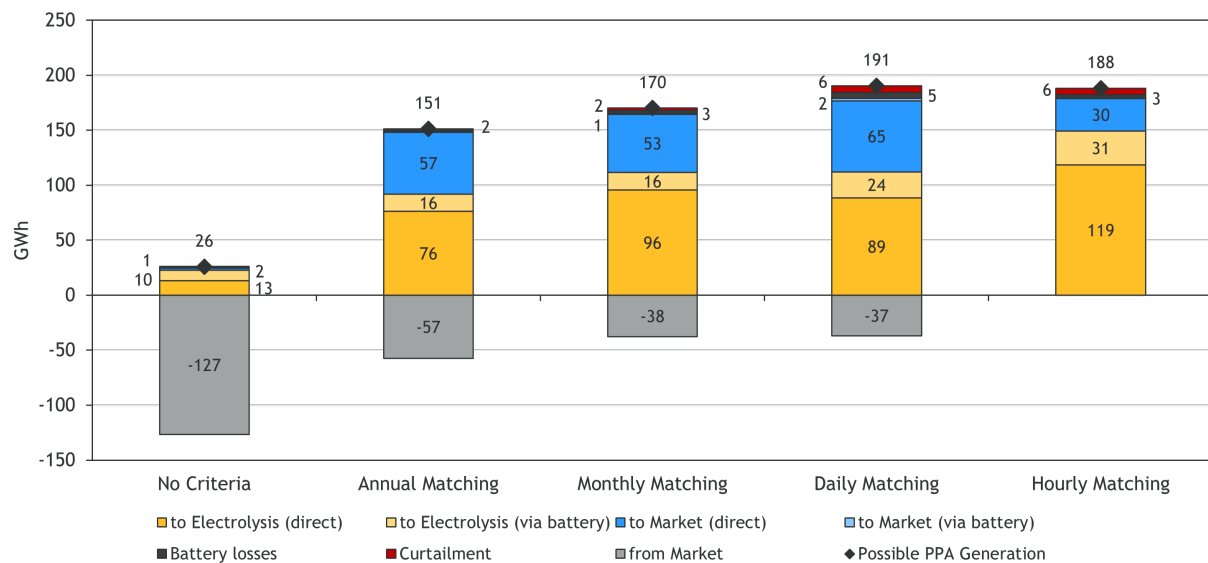


Figure 35: PPA electricity balance by use and temporal correlation requirement

The baseline analysis shows that the introduction of RFNBO criteria has a significant impact on both the cost structure, the acquisition of PPAs and the trade with the electricity wholesale market. With stricter temporal matching requirements, electricity supply shifts from flexible grid sourcing towards a stronger dependence on renewable generation and storage. This increases investment needs for PPAs and batteries while reducing the potential to trade electricity with the grid. The largest cost increase occurs between *Daily* and *Hourly Matching*, underlining the operational challenges of maintaining hydrogen production fully in line with renewable generation. The following section explores how different assumptions on storage, electricity trading, and production profiles affect these results.

### 3.2.2 Sensitivity Results

In addition to the baseline case analysis, several sensitivities are examined to better understand how specific technical and economic assumptions influence the levelized cost of hydrogen and the configuration of hydrogen production systems. Each sensitivity isolates one key parameter to examine its impact on investment patterns and cost drivers.

**No Battery** The *No Battery* sensitivity investigates the system's performance without the availability of battery storage, while the demand profile with share of baseload demand is unchanged. Comparing the results with the baseline case reveals that batteries play a crucial role in smoothing temporal fluctuations and reducing overall hydrogen costs. As shown in Figure 36, the LCOH increase substantially under *Hourly Matching* when no battery storage is available. Costs more than double in this case, rising to more than 370 EUR/MWh, while the difference is small for *Monthly Matching*. The inability to store excess renewable electricity forces hydrogen production to rely on larger, less efficient generation portfolios to maintain hourly compliance.

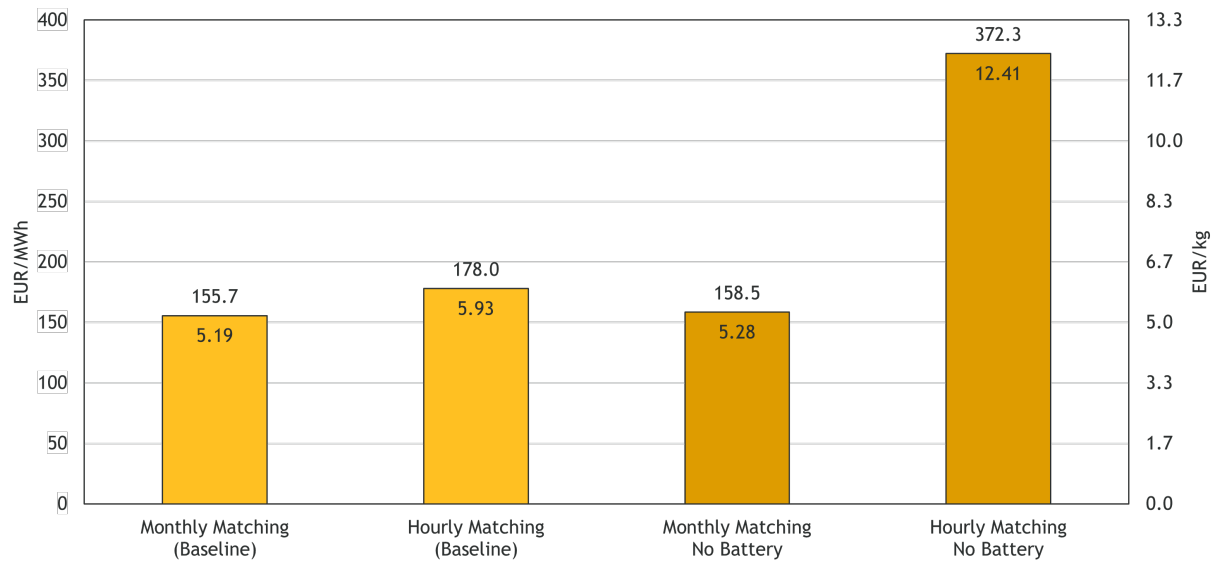


Figure 36: Levelized cost of hydrogen without battery storage

The capacity mix changes significantly in the absence of batteries (Figure 37) for *Hourly Matching*. Total installed PPA capacity increases sharply to over 340 MW<sub>el</sub>, mainly driven by wind on-shore, which partly compensates for the missing flexibility. PV deployment is reduced, as its generation profile with low full-load hours is less suited to the strict *Hourly Matching* with a partly baseload profile without intermediate storage. For *Monthly Matching*, the overall capacity remains almost the same, with a slight shift towards offshore wind. Under *Monthly Matching*, electrolyzer capacity remains close to the Baseline at around 21 MW<sub>el</sub>, whereas under *Hourly Matching* it declines to about 18 MW<sub>el</sub>.

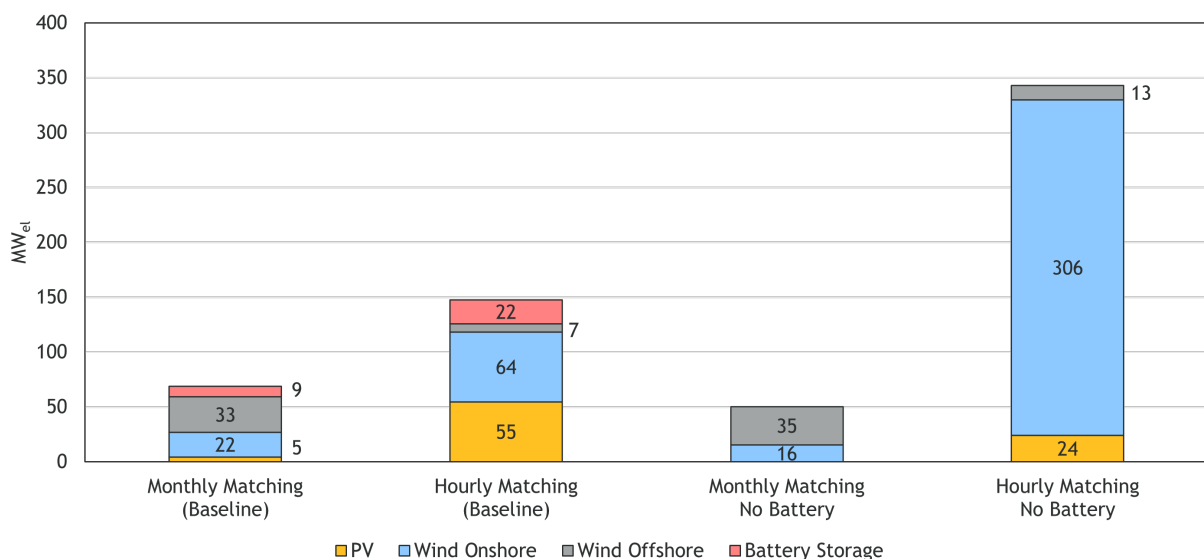


Figure 37: Installed PPA capacities by technology without battery storage

Without the ability to store surplus energy, around 316 GWh<sub>el</sub> of renewable electricity (64% of RE production) must be curtailed, compared to almost negligible curtailment in the Baseline case. Consequently, significantly more renewable capacity is required to maintain the same hydrogen output, driving up LCOH. This result underscores the importance of short-term storage for enabling cost-efficient and flexible hydrogen production under stringent temporal correlation rules.

**Electricity Trading** This sensitivity examines the impact of different limits on trading excess electricity from the dedicated PPA system to the market. In the *Baseline* scenario, a maximum of 20% of the annual PPA generation can be traded. The sensitivity explores the effects of reducing this limit to 0% (no trading allowed) and increasing it to 40% (more flexible trading).

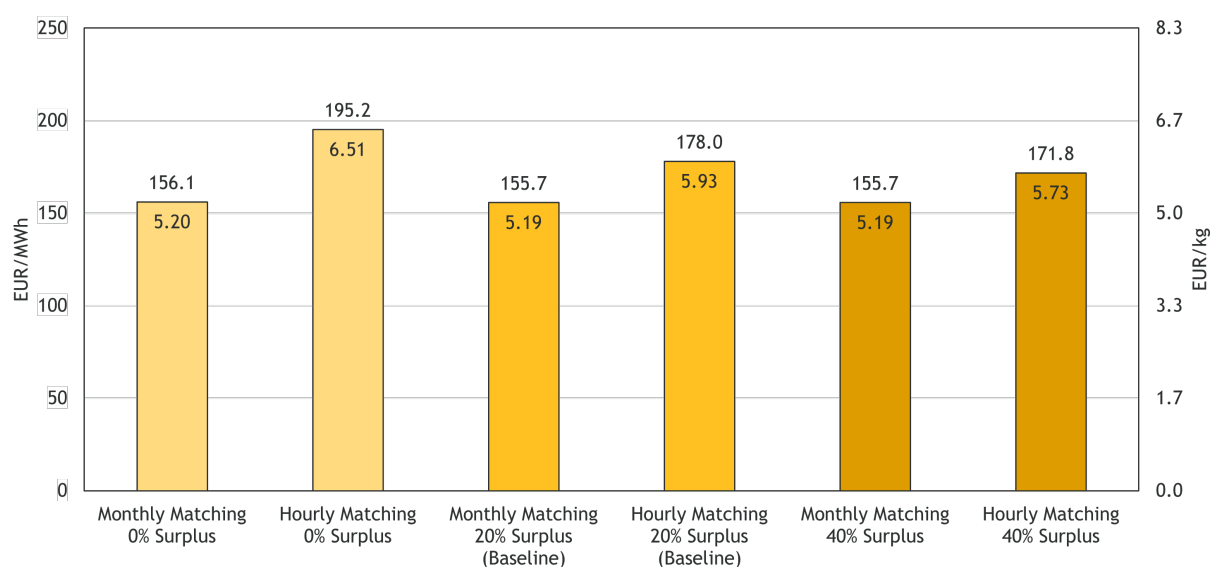


Figure 38: Levelized cost of hydrogen under different electricity trading limits

Figure 38 shows the effects of different surplus trading limits on hydrogen production costs. Under *Hourly Matching*, the LCOH increases significantly when surplus trading is prohibited, as less flexibility leads to higher curtailment and underutilized capacities. When the trading limit is increased, the LCOH decrease noticeably, reflecting the revenue opportunity of excess electricity trading. In contrast, for *Monthly Matching* the impact of trading restrictions remains negligible. This shows that under *Hourly Matching*, managing electricity trading efficiently becomes a key challenge for hydrogen producers, as trading activities have strong influence on the resulting LCOH.

For *Hourly Matching*, increasing the trading allowance leads to a significant rise in total installed PPA capacity, as shown in Figure 39. The composition of technologies shifts noticeably away from PV and batteries towards a higher share of onshore wind. This reflects the limited profitability of PV-based surplus generation, as electricity prices are often low or even negative during periods of high solar output, making surplus sales unattractive. In contrast, onshore wind offers a more

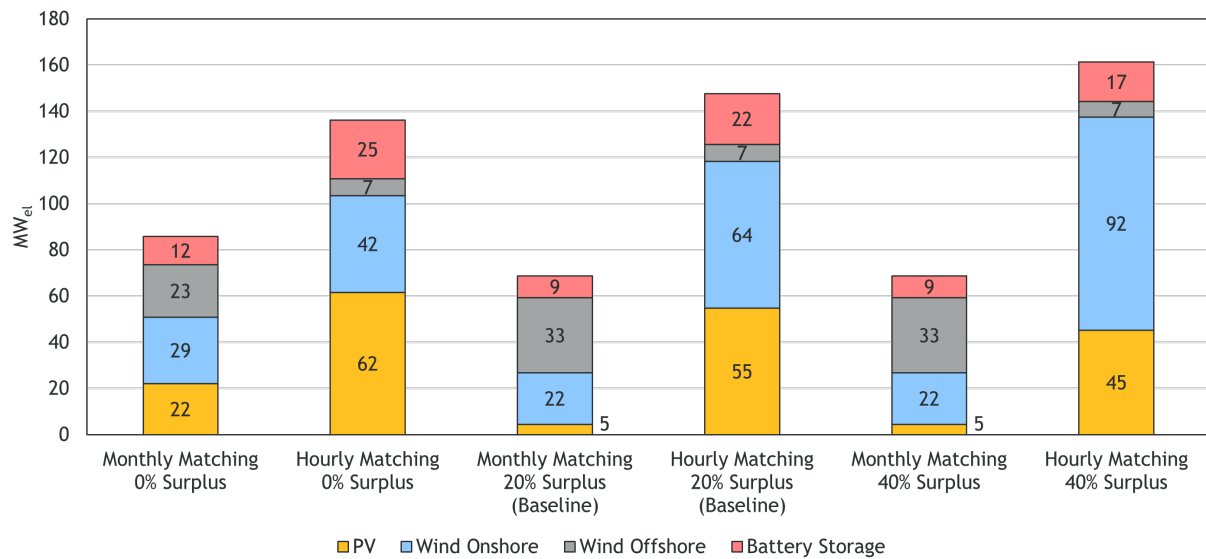


Figure 39: Installed PPA capacities by technology under different electricity trading limits

balanced generation profile, which better aligns with market price signals and hydrogen production under *Hourly Matching*. Electrolyzer capacity adjusts only marginally: with a 0% surplus limit it increases to about 22 MW<sub>el</sub>, whereas with a % surplus limit it declines slightly to about 20 MW<sub>el</sub>.

Under *Monthly Matching*, the total PPA capacity increases slightly when surplus trading is not allowed, but the offshore wind capacity decreases compared to the baseline case, so electricity generation is still higher with a surplus limit of 20%. Electrolyzer capacity stays essentially unchanged at around 21 MW<sub>el</sub> with varying surplus limits.

Overall, surplus trading proves to be a key factor for cost efficiency under *Hourly Matching*. The ability to market surplus electricity is essential to decrease LCOH, and since in reality there is no surplus limit, strong competition for PPAs with generation profiles that enable sales during high-price-periods can be expected. In contrast, under *Monthly Matching*, the influence of surplus trading remain rather small. Even shifts in the technology mix, such as a transition from PV to offshore wind, have only marginal impact on the resulting LCOH.

**Supply Profile** The third sensitivity investigates the impact of the hydrogen supply profile requirements on LCOH and installed capacities. While the baseline case assumes that 50% of the annual hydrogen production must be delivered as a baseload profile, additional cases explore completely flexible delivery (0% baseload) and continuous baseload supply (100% baseload). In this sensitivity, only the supply profile is varied; no hydrogen storage is considered, so profile compliance must be achieved on the electricity side (through the PPA portfolio with battery). The next sensitivity then introduces hydrogen storage and combines it with the same supply profiles to assess its mitigating effects.

At a fully flexible supply profile (0% baseload), the LCOH differ only slightly between monthly and *Hourly Matching*, increasing by around 14 EUR/MWh (Figure 40). However, with a stricter baseload requirement, the impact of the temporal correlation criteria becomes more prominent. For a 100% baseload supply, the difference between monthly and *Hourly Matching* rises to about 95 EUR/MWh. This illustrates that under *Hourly Matching*, hydrogen production costs are highly sensitive to delivery constraints, as continuous operation requires a constant electricity supply and thus significantly higher PPA capacities. The next sensitivity will demonstrate how hydrogen storage can mitigate these effects.

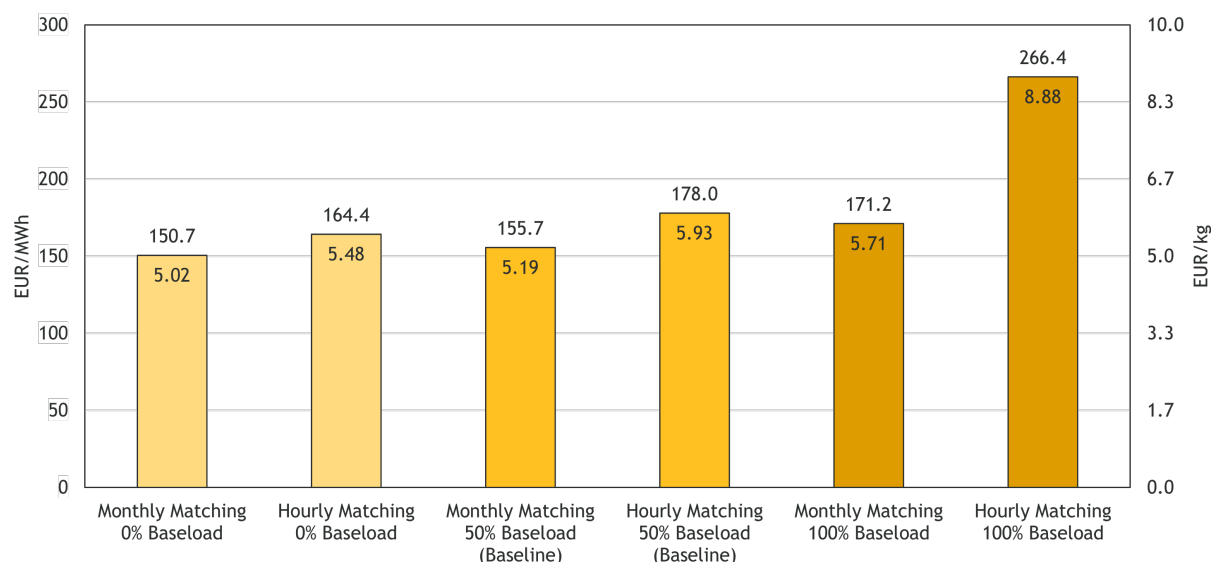


Figure 40: Levelized cost of hydrogen with different supply profiles

As shown in Figure 41, the shift towards a stricter baseload requirement substantially alters the composition and utilization of PPA assets. Under *Hourly Matching*, total installed PPA capacities increase sharply, driven mainly by a strong expansion of PV generation and battery storage. For the 100% baseload case, around two-thirds of the electricity supplied to the electrolyzer is routed through the battery, indicating its key role in balancing PV generation to maintain constant hydrogen production. However, in this configuration, 24% of the PPA generation is curtailed, and significant battery losses occur, as PV generation cannot always be utilized and sales to the grid are restricted. The PPA portfolio in *Monthly Matching* is also shifting towards PV generation and battery storage at 100% baseload. Electrolyzer capacity responds accordingly: at 0% baseload it rises to about 24-25 MW<sub>el</sub>, whereas at 100% baseload it falls to roughly 17 MW<sub>el</sub> and operates at full-load continuously, reflecting the absence of hydrogen-side flexibility. The results of this sensitivity highlight that without hydrogen storage, achieving a continuous hydrogen supply under *Hourly Matching* requires an overdimensioned and cost-intensive combination of PV and battery capacity.

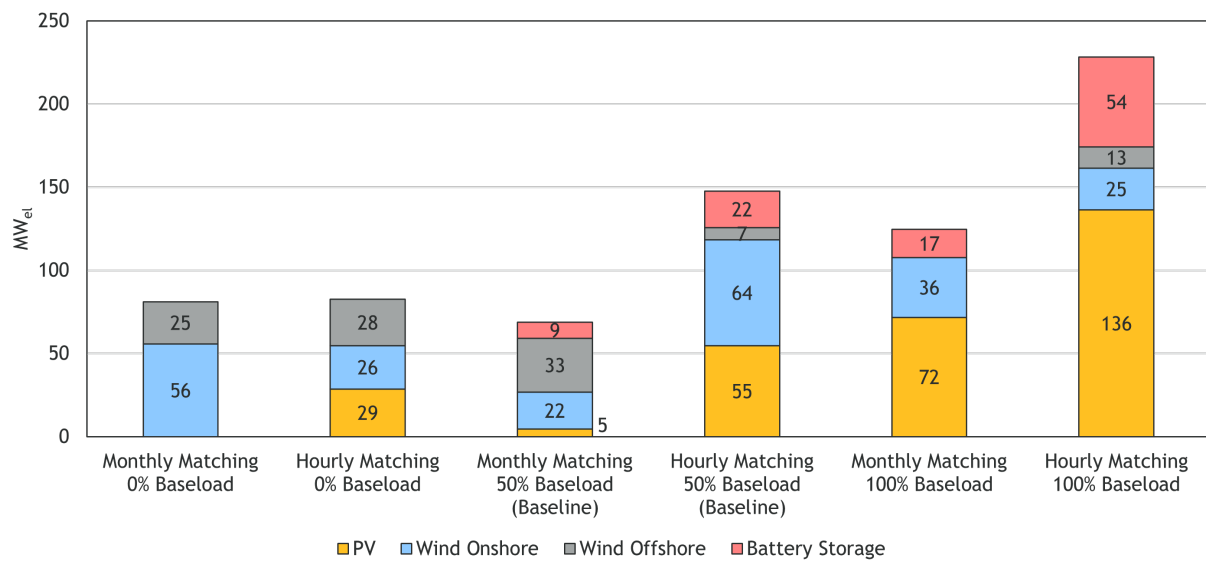


Figure 41: Installed PPA capacities by technology under different supply profiles

**Hydrogen Storage** The sensitivity *Hydrogen Storage* extends the previous analysis by introducing hydrogen storage, allowing the system to decouple electricity and hydrogen supply. This enables the electrolyzers to operate more flexibly while maintaining the required hydrogen supply profiles. As shown in Figure 42, the inclusion of hydrogen storage notably reduces the LCOH especially under *Hourly Matching*. In particular, for the 50% baseload case, the LCOH decreases by 12 EUR/MWh. With a stricter baseload requirement of the supply profile, the cost-reducing effect of hydrogen storage increases. For the 100% baseload case, the LCOH without storage reached 266 EUR/MWh in the previous sensitivity (see Figure 40), while it decreases to 169 EUR/MWh once hydrogen storage is introduced.

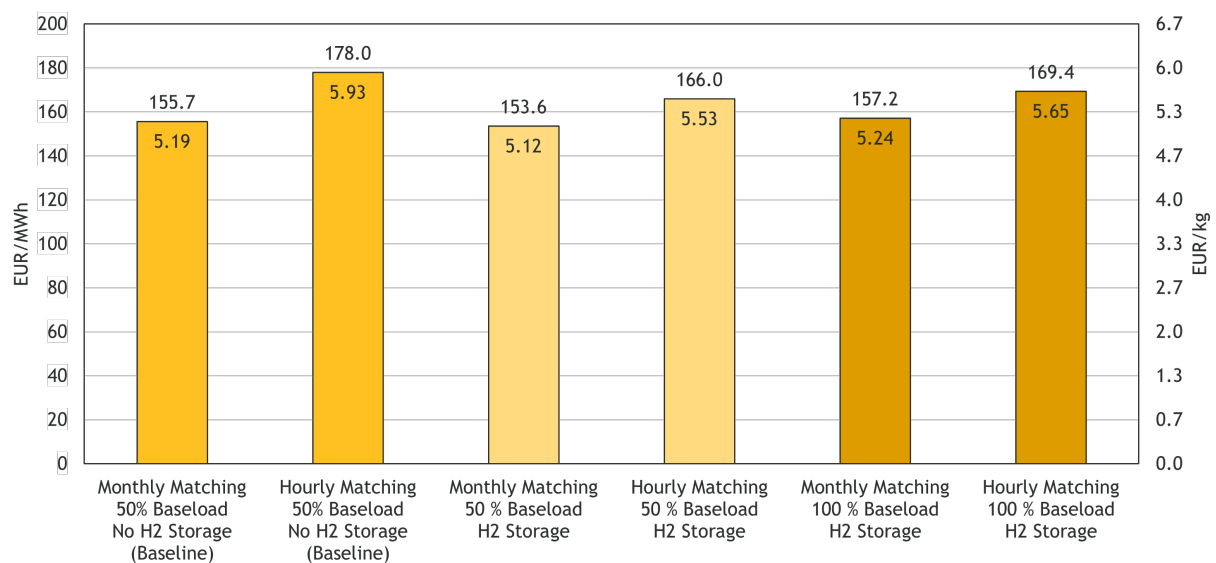


Figure 42: Levelized cost of hydrogen under different supply profiles with hydrogen storage

Figure 43 illustrates that hydrogen storage may replace the battery as a more cost-effective flexibility option. At 50% baseload requirement, the total installed PPA capacity increase slightly under *Monthly Matching* but decreases noticeably under *Hourly Matching*. For the 100% baseload case, PPA capacities decline significantly under both temporal correlation levels compared to the previous sensitivity without storage (see Figure 41). This also leads to a decrease in curtailment, as surplus generation can now be used flexibly by the electrolyzer. Electrolyzer capacity is around 23 MW<sub>el</sub> at 50% and 100% baseload, reflecting the availability of downstream flexibility in the hydrogen value chain.

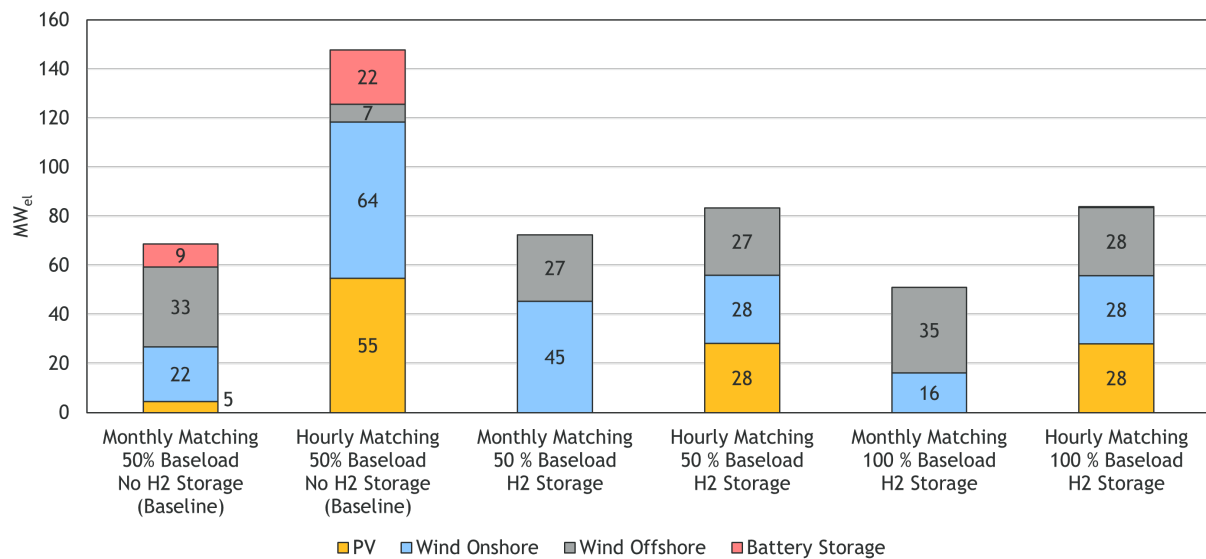


Figure 43: Installed PPA capacities by technology under different supply profiles with hydrogen storage

The inclusion of hydrogen storage reduces the differences between temporal correlation levels, as it allows a better alignment of RES generation and hydrogen production. Consequently, the impact of temporal matching criteria on LCOH strongly depends on the required supply profile and the available flexibility for structuring hydrogen production. However, in early market phases, hydrogen storage capacities are likely to remain limited.

Across all sensitivities, the *Hourly Matching* scenario reacts strongly to changes in the scenario setup: a supply profile of 100% baseload and restricted short-term flexibility could significantly increase the LCOH from roughly 170 EUR/MWh to over 370 EUR/MWh. By contrast, under *Monthly Matching* the effects are much smaller: With H<sub>2</sub> storage at 50% baseload, costs decline by only 2 EUR/MWh; removing batteries raises LCOH slightly by 3 EUR/MWh. Consequently, the difference between *Monthly* and *Hourly Matching* depends strongly on the supply profile and the available flexibility.

## 4 Conclusion

### 4.1 Summary of Findings across System and Business Perspectives

This analysis has examined the impact of the RFNBO criteria on green hydrogen production from both a *system perspective* (Section 2) and a *business perspective* (Section 3). The following section concludes and contrasts the implications of the criteria from both perspectives. Particular attention is given to how the RFNBO criteria impact costs, capacity expansion, and the need for system flexibility.

From a *system perspective*, implementing all RFNBO criteria increases **electrolysis capacity** by over 3% across Europe to meet a predefined demand, while full-load hours decline on average by around 200 h. The regional distribution is mostly influenced by exogenous production targets; however, electrolysis capacity may shift to countries with favorable RES potentials under stricter criteria. With respect to **RES capacities**, applying all RFNBO criteria adds over 25 GW<sub>el</sub> of additional RES capacity in total across Europe. In Germany, total installed RES capacities increase by 17% with all criteria. Adding RFNBO criteria removes capacities from the electricity market to be used for hydrogen production. With stricter temporal correlation requirements, hydrogen production needs RES with high full-load hours (on- and offshore wind), leaving more volatile solar generation to the electricity market. From a *business perspective*, the analysis shows similar results: tighter matching pushes portfolios toward dedicated renewables and short-term flexibility. Under *Hourly Matching* and a baseload supply profile, PV is often combined with large batteries; adding hydrogen storage can shift flexibility from the electricity sector to the hydrogen sector.

From a *system perspective*, applying all RFNBO criteria with hourly matching increases average **hydrogen supply costs** by around 10 EUR/MWh (+8%) across Europe, primarily driven by additionality and the shift from *Daily* to *Hourly Matching*. In Germany - expected to be the biggest offtaker of hydrogen in Europe - the impact of the RFNBO criteria on marginal hydrogen costs is higher than the European average (+16%). These effects highlight a distributional impact between sectors: while marginal electricity costs decline due to surplus renewables traded into the market, additional system costs remain within the hydrogen sector - implying a cost shift from electricity consumers to hydrogen producers. Average EU **electricity costs** fall by around 5% and marginal CO<sub>2</sub> certificate costs by around 2%. Because market frictions and project-level constraints may not be captured in a system model, the cost effects for an individual project might be higher. To reflect this, a *business level* analysis of **levelized cost of hydrogen (LCOH)** complements the system perspective. Results show that LCOH are more sensitive to constraints from the business perspective: in the baseline they increase from around 150 EUR/MWh (*No Criteria*) to almost 180 EUR/MWh (*Hourly Matching*), which equals +19%, with the largest jump from *Daily* to *Hourly Matching*.

Modeling different sensitivities aims at analyzing the influence of key modeling assumptions on the effects of the RFNBO criteria. From a *system perspective*, electrolysis CAPEX have no significant effect on the relative impact of RFNBO criteria. **Limiting non-European imports** increases

EU production needs; the absolute RES and electrolysis capacities increase while the incremental effect of RFNBO criteria decreases slightly as less favorable potentials are already in use without criteria. **Constraining hydrogen storage potentials** raises electrolyzer capacity but has only a minor impact on marginal hydrogen costs under full RFNBO implementation. The largest effect arises when **country-specific production targets** are disregarded: costs and capacities decrease in the scenario without RFNBO criteria compared to the base with targets; the RFNBO cost increase is smaller; and production concentrates more strongly in selected regions. From a *business perspective*, sensitivities have a much stronger impact than in the system analysis, especially under *Hourly Matching*, where the LCOH span from about 170 EUR/MWh up to 370 EUR/MWh. The difference between *Monthly* and *Hourly Matching* ranges from roughly 15 EUR/MWh to over 90 EUR/MWh. **Short-term flexibility** (batteries or hydrogen storage), the ability to trade electricity surpluses from PPAs, and the chosen **supply profile** are decisive drivers of project-level costs. Where hydrogen storage is available, differences between matching requirements decrease and required PPA capacities and curtailment fall; where storage and trading options are limited, LCOH rise sharply.

The modeling of the European Energy System from the *system perspective* underestimates the operational challenges for individual hydrogen production projects - especially the temporal matching. Procurement complexities, necessary overbuilding to achieve acceptable full-load hours, and operational constraints may increase actual business-case costs above modeled values. While the *business perspective* is designed to be closer to real project economics - capturing project-level portfolio design and PPA prices - it still assumes perfect foresight and frictionless execution. Consequently, the reported LCOH should be interpreted as a lower bound even in the business perspective.

## 4.2 Implications on the Individual Criteria

The three RFNBO criteria - additionality, geographical correlation, and temporal correlation - have cross-cutting implications across the system and business perspectives. Additionally, they impose practical consequences for the procurement and operation of hydrogen projects, as well as their coordination with the electricity system, that are not necessarily covered with one of the models of the analysis.

**Additionality:** The criterion of additionality separates newly built RES capacity into market and hydrogen-dedicated plants. This limits the availability of electrolyzers to provide flexibility in the electricity market. For the end users, it shifts the resulting additional system costs partly towards hydrogen consumers. For hydrogen production projects, additionality tightens the PPA market as existing RES are not allowed to be used for hydrogen production purposes. In Germany, hydrogen producer may have to compete with the EEG feed-in tariffs for the procurement of PPAs. Furthermore, additionality requires tightly synchronized planning and construction of RES and electrolysis, which may delay the operation of green assets.

**Geographical correlation:** Requiring generation and electrolysis to be located in the same bidding zone narrows the set of viable PPAs. In addition, it reduces the possibilities to balance weaker regional resources with stronger resources elsewhere or to balance regional weather conditions. In practice, the geographical correlation intensifies competition for in-zone PPAs and may increase the risk of scarcity prices or market power abuse. This criterion also heightens exposure to regulatory changes, e.g. bidding zone redefinitions that could affect compliance.

**Temporal correlation:** Stricter temporal correlation shifts electricity procurement for hydrogen production towards high full-load-hour RES and increases the need for flexibility. At *Monthly Matching*, a substantial part of this alignment can be achieved with limited operational complexity. Moving to *Hourly Matching* stresses the need for short-time flexibility, reduces the electrolyzer full-load hours, and favors wind over PV in the dedicated portfolio. This may lead to a market pull of wind PPAs for electrolyzers, leaving volatile solar production for the electricity market. With the strict temporal correlation, dedicated PPA capacities for hydrogen production increase, resulting in a significant electricity surplus which is fed back into the electricity market. This may contradict the aspiration that hydrogen production can be used to utilize excess electricity which would otherwise be curtailed. Additionally, *Hourly Matching* requires flexible operation by the electrolyzer, which may impose technical difficulties regarding the operation and maintenance of the plant. From the business perspective, a tighter temporal correlation makes the project more sensible to supply-profile requirements and market access. Hydrogen storage may substitute batteries as the primary flexibility option and narrow the gap between temporal correlation levels. A stricter temporal correlation also leads to overdimensioning of PPAs, though efficient trading helps monetize surplus generation. This results to an increased market exposure for the hydrogen producers, as the revenue is more dependent on the value of excess electricity and the uncertainty of weather and electricity price forecasts. In addition, the effort to sell the excess electricity increases.

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## Abbreviations

|                |                                                               |
|----------------|---------------------------------------------------------------|
| <b>BlmSchG</b> | Federal Immission Control Act (Bundes-Immissionsschutzgesetz) |
| <b>CAPEX</b>   | Capital expenditures                                          |
| <b>ERAA</b>    | European Resource Adequacy Assessment                         |
| <b>EU</b>      | European Union                                                |
| <b>EWI</b>     | Institute of Energy Economics at the University of Cologne    |
| <b>EV</b>      | Electric vehicle                                              |
| <b>HP</b>      | Heat pump                                                     |
| <b>LCOH</b>    | Levelized costs of hydrogen                                   |
| <b>NTC</b>     | Net transfer capacities                                       |
| <b>PPA</b>     | Power purchase agreement                                      |
| <b>RED II</b>  | Renewable Energy Directive II                                 |
| <b>TYNDP</b>   | Ten-year network development plan                             |