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Assessing Green Hydrogen Support Mechanisms in Coupled Electricity and Hydrogen Markets

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Green hydrogen is expected to play an important role for decarbonizing hard-to-abate sectors but faces regulatory, economic, and operational barriers. In the EU, strict renewable energy usages requirements and temporal and geographical criteria constrain green hydrogen production and complicate integration with electricity markets. Support mechanisms (SMs), such as premiums and quotas, aim to boost hydrogen production, yet their impacts on coupled electricity-hydrogen systems remain underexplored. This paper extends a previous joint electricity-hydrogen Cournot equilibrium model to represent and analyze the impact of different green hydrogen production SMs. Different SMs lead to different equilibrium models that were solved using equivalent quadratic optimization problems and applied to real-size Iberian case studies. Results reveal how different SMs influence hydrogen and electricity prices, production and emissions, highlighting trade-offs among stakeholders. The findings provide guidance for designing balanced policies that stimulate green hydrogen while minimizing unintended consequences and offer flexible tools to assess regulatory and economic interactions in emerging hydrogen markets.

Abbreviations

AEL	Alkaline Electrolyzer
Batt	Batteries
CCGT	Combined Cycle Gas Turbines
CfD	Contract for Differences
DC	Direct Connection
El	Electrolyzers
EU	European Union
EV	Electric Vehicle
FinOT	Financial Off-Take
FP	Fixed Premium
HPA	Hydrogen Purchase Agreement
LHV	Low Heating Value
LoH	Level of Hydrogen
NECP	National Energy and Climate Plan
NG	Natural Gas
NoSub	No Subsidies
PEM	Polymer Electrolyte Membrane Electrolyzer
PhOT	Physical Off-Take
PPA	Power Purchase Agreement
RA	Relaxing Additionality
RE	Renewable Energy
RFNBO	Renewable Fuels of Non-Biological Origin
SM	Support Mechanism
SMR	Steam Methane Reforming
SoC	State-of-Charge
TTF	Title Transfer Facility

Nomenclature

Indexes	
e, e'	Agents
$-e$	All agents but agent e
h	Hours
y	Years
j	Wind and solar technologies
t	Thermal power plants
u	Hydro units
s	Batteries
v	Hydrogen tanks (vessels) for storage
o	Other technologies
Parameters (capital and Greek letters)	
$D_0^w, D_0^{w,H2}$	Wholesale electricity/hydrogen demand intercept [MWh]
$\alpha_0^w, \alpha_0^{w,H2}$	Wholesale electricity/hydrogen demand slope [MW/€/MWh, tonH2/€/tonH2]
$\theta_0^w, \theta_0^{w,H2}$	Electricity/hydrogen Cournot conjecture [€/MWh/MW, €/tonH2/tonH2]
Parameters for SPs	
FP^{H2}	Fixed premium [€/kg H_2]
$Q_e^{CH2,S}$	Maximum hydrogen subsidized [ton H_2]
P^{off}	Strike price set in the government FinOT [€/kg H_2]
P^{HPA}	Government PhOTp price [€/kg H_2]
Q_e^{HPA}	Government PhOT volume [ton H_2]
$Q_e^{CH2,off}$	Hydrogen production set in the government FinOT [ton H_2]

Q_e^{CH2}	Annual green hydrogen quota [ton H_2]
Parameters for PPAs	
$Q_e^{PPA,s}$, $L_e^{PPA,s}$	RE sold and selling electricity price set in physical PPAs [MWh, €/MWh]
$Q_e^{H2,PPA}$, $L_e^{H2,PPA}$	Hydrogen produced and purchased electricity price set in RE-PPAs [tonH_2, €/MWh]
Parameters for El	
η	Electrolysis efficiency [%]
CAP_e^{CH2}	Electrolyzer capacity [MW]
Parameters for batteries	
η^{ch},η^{dis}	Battery charge/discharge efficiency [%]
CAP_{es}	Battery capacity [MW]
SOC_{es}^{min},SOC_{es}^{MAX}	Minimum/maximum SoC [MWh]
Parameters for H_2 tanks	
$\eta^{ch,H2}$,$\eta^{dis,H2}$	H_2 tank charge/discharge efficiency [%]
CAP_{ev}^{H2}	Hydrogen tank capacity [ton H_2]
$LOH_{ev}^{min,H2}$, $LOH_{ev}^{MAX,H2}$	Minimum/maximum LoH in the tanks [tonH_2]
ε	Coefficient loss in the hydrogen tanks [%/h]
Variables (lowercase letters)	
d^w,$d^{H2,w}$	Cleared wholesale electricity/hydrogen demand [MWh, tonH_2]
p,p^{H2}	Wholesale electricity/hydrogen price [€/MWh, €/tonH_2]
Variables per agent	
d^w,$d^{H2,w}$	Cleared wholesale electricity/hydrogen demand [MWh, tonH_2]
p,p^{H2}	Wholesale electricity/hydrogen price [€/MWh, €/tonH_2]
q_e	Electricity production [MWh]
q_e^{CH2}	Green hydrogen production [tonH_2]
$q_e^{CH2,S}$	Subsidized green hydrogen production [tonH_2]
$q_e^{CH2,NS}$	Unsubsidized green hydrogen production [tonH_2]
$q_e^{H2,DC}$	Green hydrogen production in DC facilities [tonH_2]
$q_e^{H2,grid}$	Green hydrogen production consuming electricity from grid [tonH_2]
q_e^{NH2}	Non-renewable (gray) hydrogen production [tonH_2]
Variables per technology	
q_{ej}	RE production [MWh]
q_{ej}^{DC}	RE production within the DC facilities [MWh]
q_{et}	Thermal power plants production [MWh]
q_{eu}, b_{eu}	Hydro production/energy pumped [MWh]
q_{es} , b_{es}	Battery discharge/charge [MWh]
q_{ev}^{H2} ,b_{ev}^{H2}	Hydrogen released/charged from/to the tanks [MWh]
q_{eo}	Other electricity technologies production [MWh]
Hourly variables	
soc_{esh}	SoC of the battery [MWh]
q_{evh}^{H2} , b_{evh}^{H2}	Hydrogen released/charged from/to the tanks [MWh]
loh_{evh}^{H2}	Level of hydrogen [tonH_2]
$q_{evh}^{H2,loss}$	Hourly losses in the hydrogen tank [tonH_2]
Functions (lowercase letters)	
$d^w(\cdot)$, $d^{w,H2}(\cdot)$	Wholesale electricity/hydrogen demand curves [MWh]
$b_e(\cdot)$, $b_e^{H2}(\cdot)$	Electricity/hydrogen market profit [€]
$c_e(\cdot)$, $c_e^{RH2}(\cdot)$, $c_e^{GH2}(\cdot)$	Electricity/green hydrogen/gray hydrogen production cost [€]

1. Introduction

The global economy is advancing towards a net-zero and sustainable future, where electrification relying on Renewable Energy (RE) is expected to play a crucial role [1], [2]. Projections suggest that global electrification could rise from the current 20000 TWh to 90000 TWh by 2050 [3], [4], and can be classified into two main approaches:

- Direct electrification: involves replacing processes reliant on pollutant energy sources, like combustion, with electricity, as is the case, for example, in the transition from combustion engine vehicles to Electric Vehicles (EVs).
- Indirect electrification: entails synthetic fuels or chemicals from electricity to be used in existing or alternative technologies, when direct electricity use is not feasible or cost-effective. For example, the case of using hydrogen instead of carbon in the steel industry.

Direct electrification is highly efficient and is being adopted in applications such as heating (e.g., power-to-heat, systems like heat pumps and electric furnaces), transportation (EVs), and energy storage (e.g., power-to-power, systems involving batteries) [5], [6], [7]. However, direct electrification is not always feasible, particularly in sectors requiring high energy densities or specific chemical feedstocks. In these cases, indirect electrification offers a viable alternative for decarbonizing through the power-to-X concept, where X denotes another energy driver such as the chemical or fuel synthesized [5], [8]. Examples include ammonia (NH_3) for fertilizers, methane (CH_4) for power generation, and hydrogen (H_2) for energy storage [8], [9]. Among these, power-to-hydrogen has gained special attention due to its versatility and its potential to address decarbonization challenges across diverse sectors, including transportation, industry (e.g., steel, chemical, refining), heating, and power generation [10], [11], [12]. This versatility supports the Green Hydrogen Economy concept, an economic model based on large-scale hydrogen production from RE, distribution, and use in different applications, to replace or complement carbon-intensive processes, with hydrogen acting as a key energy carrier in a global energy system [13], [14], [15], [16], [17], [18]. Nonetheless, realizing the full potential of hydrogen requires overcoming significant barriers, particularly related to economic feasibility and technical challenges such as efficient storage and transportation [17], [19].

One of the key aspects of the Green Hydrogen Economy is its strong interconnection with the electricity sector [17], [18]. Indeed, hydrogen production through electrolysis (an electrochemical process that splits water molecules into hydrogen and oxygen) depends on electricity prices and the availability of RE [11], [20], [21]. However, integrating electrolytic hydrogen production into the energy system may lead to unintended consequences. For instance, as proofed in [22] and [23], allocating RE for hydrogen production may increase emissions if thermal power plants are required to meet conventional electricity demand. Considering these potential issues, the European Union (EU) established a regulatory framework for Renewable Fuels of Non-Biological Origin (RFNBO), including green hydrogen (also referred as clean, renewable or low-carbon hydrogen), through the Delegated Act 2023/1184 [24]. This directive, together with the Renewable Energy Directive (RED III) [25], aims to ensure an efficient RE utilization while boosting hydrogen adoption. To achieve these goals, three fundamental criteria were introduced to consider electrolytic hydrogen as green hydrogen [20], [24], [26], [27], [28]:

- Additionality: to ensure that the RE used for green hydrogen production comes from new additional RE facilities, beyond those already planned to meet the final electricity consumption targets. These additional RE facilities must begin operation 36 months prior to the hydrogen production facility and must not have received operational or investment subsidies. Compliance with additionality can be ensured either through a dedicated RE facility, consisting in a RE plant primarily intended to power the electrolyzer, and potentially injecting surplus electricity into the grid, or by securing electricity via Power Purchase Agreements (PPAs) signed with newly built unsubsidized RE generators. Furthermore, in an expected high RE penetration (especially post-2030), additionality is also considered to be met when hydrogen production demonstrably occurs during periods of RE curtailment, thus reducing grid congestion and maximizing RE utilization.
- Temporal correlation: to ensure the chronological alignment of green hydrogen production with RE generation, in two progressive time periods. Until 2030, to be green, hydrogen must be produced during the same calendar month in which the corresponding RE generation is allocated. After 2030, this alignment must be hourly. In any case, electrolytic hydrogen is considered green if the wholesale electricity price is below 20 €/MWh or less than 0.36 times the cost of carbon emission allowances, corresponding to a system with a mainly RE mix.
- Geographical correlation: to ensure that hydrogen production occurs in specific areas where RE is generated. To produce green hydrogen, RE must come from the bidding zone where the electrolyzer is located, or the electricity used must be imported from interconnected zones with similar or higher wholesale prices, including offshore areas under RE-based PPAs.

The reason underlying these criteria is to ensure that green hydrogen production does not indirectly increase emissions, compete for RE with conventional electricity demand and, that it improves RE utilization. By requiring additionality, temporal, and geographical correlation, the EU ensures that hydrogen labelled as "green" truly contributes to decarbonization and supports the expansion of additional RE capacity. Note that while compliance with these three criteria (additionality, temporal, and geographical correlation) results in the classification of hydrogen as green, this is not the only scenario for hydrogen to be considered green.

Following these guidelines, several approaches have been proposed to classify hydrogen as green based on the European regulation [20], [24], [29], [30], comprising, among others:

- Direct connection (DC): a dedicated RE facility supplies electricity directly to the electrolyzer. The facility may be grid-connected but must prove that no grid electricity is used for hydrogen production. It can be combined with a PPA as long as it complies with the additionality, temporal and geographical correlation criteria [31]. Electricity surplus can still be fed into the grid. Since electricity is consumed simultaneously at the same location where it is produced, temporal and geographical correlation criteria are inherently satisfied.
- Production using RE-based PPAs: hydrogen producers may secure electricity through PPAs associated with RE installations that fulfill additionality, temporal, and geographical correlation criteria.
- High RE penetration: to be green, hydrogen can be produced in bidding zones where the annual average RE share exceeds 90%. Production hours must be limited to periods when the RE share surpasses this threshold, encouraging production during high RE availability. In this case, additionality and temporal and geographical correlations are no longer required since the Delegated Act assumes that the electricity sector is fully renewable.
- Low emissions scenario: hydrogen is green if producing facilities operate in a bidding zone with an emission intensity below 18 gCO_2-eq/MJ (65 kg CO_2/MWh), since this reflects a mainly RE mix. In addition, electricity must be supplied with a RE-based PPA, but the PPA must comply with temporal and geographical correlations.
- Reducing curtailment: hydrogen production must occur during periods of RE curtailment, thus contributing for a better RE usage. Producers must provide, with evidence from the transmission system operator, that production aligns with curtailment and reduces the need for redispatch. This way, hydrogen production helps to reduce grid costs by minimizing the need for power flow adjustments (redispatch) and supports grid stability during peak renewable generation periods, which is critical in systems with high shares of RE.

Considering all the above, Table 1 summarizes these approaches, highlighting the RE source and the requirements that must be fulfilled regarding additionality, temporal and geographical correlations [20], [24], [29], [30]:

Table 1. RE source and requirements to classify hydrogen as green

Approach	RE source	Additionality	Temporal correlation	Geographical correlation
Direct connection	Dedicated facility	Yes	Naturally satisfied	Naturally satisfied
RE PPAs	Contract	Yes	Yes	Yes
High RE penetration	Grid (market)	No	No	No
Low emissions	Contract	No	Yes	Yes
Reducing curtailment	Grid (market)	No	No	No

The above approaches introduce significant complexity by imposing strict requirements on green hydrogen production and its deployment. This, combined with its high investment costs and the absence of an organized hydrogen market, may slow down its development [32], [33], [34]. In this context, green hydrogen producers are exposed to two main market risks. On the one hand, price risk arises from the uncertainty about future hydrogen prices, which may fall below production costs and make projects unprofitable. On the other hand, volume risk refers to the uncertainty about the quantity of hydrogen that can be sold due to limited or unpredictable demand.

To reduce these barriers, support mechanism (SMs) such as subsidies, tax incentives, and feed-in tariffs can be considered as energy policy instruments [17]. These mechanisms can help to bridge the cost gap and establish a viable and competitive market for green hydrogen [35]. In addition, they can reduce economic barriers and make green hydrogen more attractive for producers and consumers until economies of scale and technological improvements make it cost-competitive.

Table 2 summarizes the most relevant SMs for green hydrogen production identified in the literature, classified according to whether they address the risk of low prices, low volumes, or both, including also a brief description of each SM and their most relevant characteristics. The table focuses on subsidies for green hydrogen production rather than subsidies for investments in new green hydrogen infrastructures. For these last subsidies to be effective, they should allow producers to recover their total production costs, which may be difficult in the face of low hydrogen prices or limited market demand [36].

Table 2. Main SMs for green hydrogen production

Ref.	SM	Risk covered	Description	Characteristics
[34], [36], [37]	Fixed price	Price	A certain amount of hydrogen sold at a predetermined price, ensuring stable revenue but with risk if costs exceed it or market prices rise.	Provides predictable income Shields producers from price volatility. Can reduce profitability if fixed price is too low. Producers lose potential gains when market prices are higher
[34], [35], [36], [38], [37], [39]	Fixed premium	Price	A certain amount of hydrogen is sold at market price plus a constant premium, increasing revenue.	Revenue increases through premium. Exposed to market price fluctuations. No adjustment to rising production costs. Risk of financial losses if costs exceed revenues. Not completely protected against cost or price volatility
[35], [36], [38], [37], [40], [41],	Variable premium	Price	Premium covers gap between a reference and a strike price, stabilizing income but possibly requiring repayments.	Protects against price volatility. Adjusts revenue to maintain minimum returns. Producers may pay back extra revenues if market price exceeds strike. Can be defined hourly or over longer periods.
[36], [37], [42], [43], [44]	Government PhOT (physical off-take)	Volume and price	Government buys a specified volume of hydrogen at a fixed price, using it directly or redistributing it to other off-takers.	Guarantees a stable buyer. Ensures production cost coverage. Hydrogen can serve public demand or be redistributed. Government must avoid market distortions.
[36], [37], [44]	Government FinOT (financial off-take)	Volume and price	Government grants CfDs (contract for difference) up to a maximum volume without assuming physical delivery, leaving producers responsible for selling hydrogen	Stabilizes revenues via CfDs. Producers must secure market buyers Ensures minimum economic return. Penalties possible if hydrogen is not sold.
[34], [37], [45]	Quotas	Volume	Minimum hydrogen shares mandated for specific uses, guaranteeing demand but risking inefficiencies.	Creates a guaranteed consumer base. Increases adoption in targeted sectors. Stimulates long-term hydrogen demand. Risks shortages or inefficiencies if demand and infrastructure are not developed.

As can be seen, assessing the implications of green hydrogen SMs in electricity and hydrogen markets introduces multiple challenges, including:

- Regulatory challenges: hydrogen producers aiming to benefit from green hydrogen incentives must comply with not only the Delegated Act, but also other regulatory frameworks, such as those concerning grid access and market participation. Policymakers must ensure that policies strike a balance between promoting green hydrogen at reasonable costs and boosting a competitive environment. Moreover, new subsidies should be designed with clear and consistent regulatory frameworks that incentivize green hydrogen production, minimize market distortions, and avoid excessive burdens on producers.
- Economic challenges: producers must ensure the economic viability of operating in both electricity and hydrogen markets, managing high capital and operational costs, being exposed to volatile market prices, and often facing insufficient or uncertain support schemes, particularly since an organized hydrogen market does not yet exist, even though the EU aims to promote it.
- Operational challenges system operators must ensure that RE is used efficiently (i.e., minimizing curtailments) while promoting electrolytic hydrogen production at minimum cost.

In this sense, mathematical models offer a robust approach to address these challenges. By simulating market dynamics, resource allocation, and production strategies, mathematical models can help producers to evaluate different scenarios and make informed decisions. Models also provide valuable insights for regulators, policymakers and system operators, enabling them to assess the potential impacts of subsidiary policies and identify optimal regulatory pathways. These models also offer tools to evaluate risks and opportunities within interconnected energy markets [46].

Previous studies based on have analyzed additionality, temporal and geographical requirements with mathematical models [23], [47], [48], [49]. Their findings suggest that hourly temporal correlation may lead to lower carbon intensity in the hydrogen sector but reduces the profits. Conversely, relaxing geographical requirements improves economics with minimal environmental impact, indicating that a so strict geographical correlation may be unnecessary. On the other hand, additionality requirement may slow down electrolyzers deployment due to restricted RE availability which may need further investments in both transmission and RE capacity.

On the other hand, the role of some SMs have been analyzed in [45], which iteratively solved the European electricity and gas markets to assess the impact of a green hydrogen quota in the gas system. Their findings show that such a quota can boost RE capacity and slightly reduce gas prices. However, it also increases electricity prices due to higher CO_2 costs and leads to a decline in total welfare. This occurs because the increased electricity demand for hydrogen producers required to meet the quota results in a higher emission allowance price, since the power sector's emissions are capped. Similarly, [35] examined various SMs for hydrogen, including fixed premiums, CfDs, and investment-related incentives, under a perfect competition scenario. The study found that mechanisms remunerating hydrogen production, such as fixed premiums and CfDs, cause greater distortions in electricity and hydrogen spot prices compared to investment mechanisms. While these mechanisms promote RE production and discourage investment in thermal power plants, the resulting emission reductions in the power sector led to higher emissions in the industrial and hydrogen sectors. Additionally, production-based mechanisms introduce operational distortions that typically increase costs to a greater extent than the investment distortions associated with capacity-based mechanisms.

However, modelling EU's green hydrogen and the role of its SMs is still a challenge. In this sense, to the best of authors' knowledge, there are no previous works analyzing both issues under imperfect competition. In this sense, this paper aims to close this gap with the following contributions:

- Formulation of new joint Cournot models to represent different green hydrogen approaches, departing from the joint Cournot model presented in [50], [51] and [52]. Specifically, this paper formulates: 1) the Direct Connection approach with no grid correlation 2) RE PPAs approach with temporal and geographical correlation; and 3) the Reducing Curtailment approach (see Table 1). High RE penetration or low-emissions approaches are excluded but could be addressed with an iterative and ex-post validation, increasing, however, the model's complexity.
- Assessment of the impact of relaxing the additionality requirements, its potential to boost green hydrogen production and its effects on the coupled electricity-hydrogen system.
- Price risk (fixed premium), volume risk (quota), and support mechanisms for both (physical and financial off-takes) are also modeled
- Development of equivalent mathematical optimization problems, based on convex reformulations, to solve the new Cournot models proposed. These equivalent optimization problems ease substantially the resolution [53].
- Application of the models to real-size case studies for the Iberian system to compare the impact of the different SMs in the system (dispatch), economic (costs, profits, price, etc.) and environment (emissions).

The remainder of this paper is organized as follows. The next section provides a general description and view of the proposed models. Section 3 presents the formulation of the proposed Cournot models, first without SMs (as in [52]) and then incorporating them. Section 4 presents additional constraints that complete the models. Section 5 outlines case studies, followed by the results and discussion. Section 6 concludes and highlights directions for future research. Finally, Appendix A. provides the mathematical proofs for the equivalent optimization models, Appendix B. the main data used for the cases studies while Appendix C. provides additional economic results.

2. General overview of the proposed approach

Figure 1 presents a stylized overview of the proposed models, highlighting the main components.

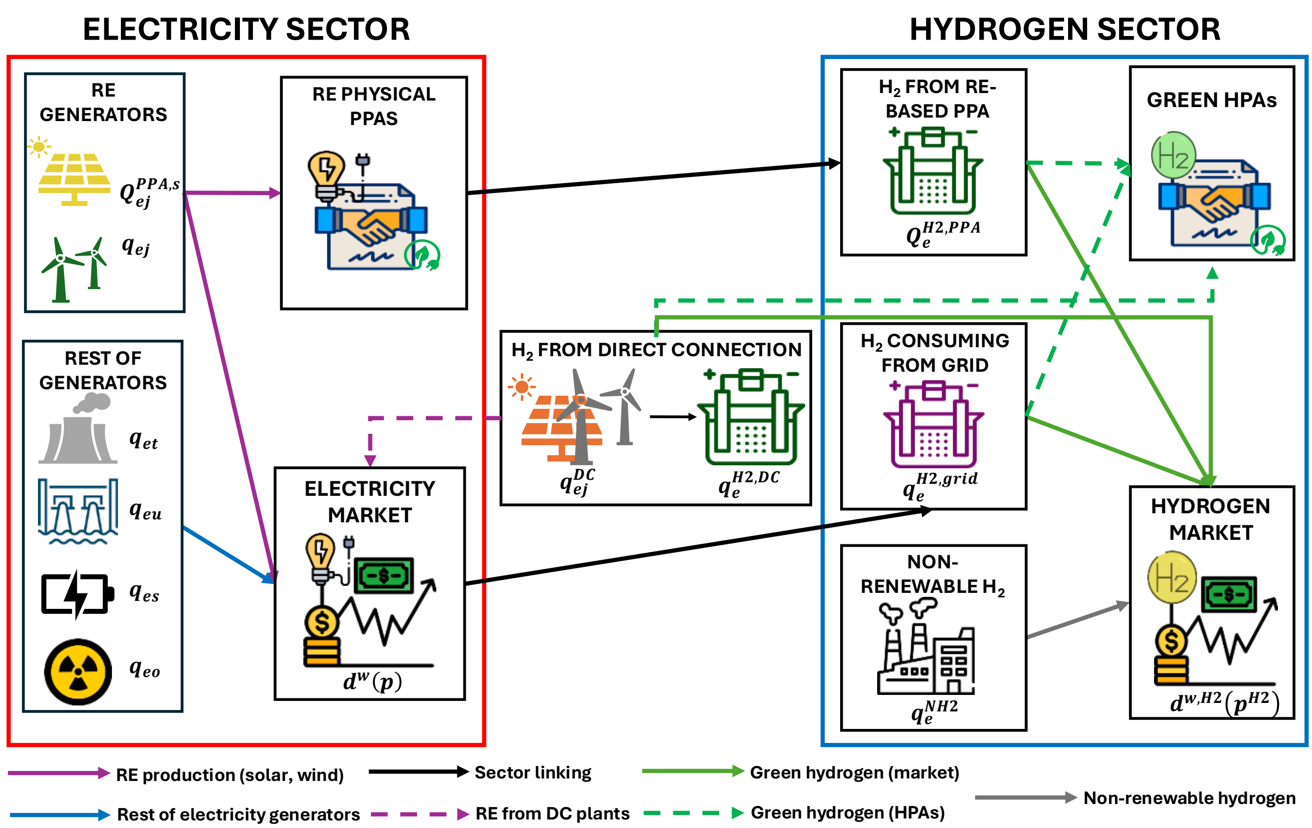

Figure 1. Overall view of the model

In the electricity sector, electricity can be generated from RE technologies (solar and wind), q_{ej}; thermal power plants, q_{et}; hydro units, q_{eu}; batteries, q_{es}; and other technologies, q_{eo}. RE generation is depicted with purple arrows, while the production from remaining technologies with blue ones. Solar and wind energy can be allocated to either physical PPAs, $Q_{ej}^{PPA,s}$, or to meet the wholesale electricity market demand, d^{w}. In contrast, the rest of technologies supply their production exclusively to the wholesale market.

In the hydrogen sector, green hydrogen, whose flows are represented with green arrows, can be provided with different alternatives:

1. Through green PPAs, whose production is denoted as $Q_{e}^{H2,PPA}$.
2. Consuming RE electricity from the grid at the wholesale electricity price, (green hydrogen denoted as $q_{e}^{H2,grid}$).
3. With direct connections ($q_{e}^{H2,DC}$), where a dedicated RE facility supplies directly the electricity consumed by the electrolyzers. As stated in the introduction, these facilities are not allowed to purchase electricity from the grid but can still sell their RE surplus to the wholesale market, which is represented with a dashed purple arrow in Figure 1.

The first two alternatives directly link the hydrogen and electricity sectors, as represented in Figure 1 by black arrows, since hydrogen production depends on electricity consumption either at market prices or under PPAs. The third alternative, based on a dedicated RE plant, also interacts with the electricity sector, as the plant can either use its electricity for hydrogen production or sell it in the wholesale electricity market.

Finally, q_{e}^{NH2}, represents gray hydrogen produced via Steam Methane Reforming (SMR), depicted by gray arrows. Green and gray hydrogen supply the demand $d^{w,H2}$, in the wholesale market, represented by solid green arrows. In addition, under physical government off-takes, green hydrogen can also be allocated to Hydrogen Purchase Agreements (HPAs), illustrated with dashed green arrows, as will be further discussed in section 3.3.

3. Formulation and resolution of the proposed Cournot models

This section describes the main mathematical features of the proposed models without and with SMs (subsection 3.1 and subsections 3.2-3.5 respectively). The models have an hourly granularity, but time-related indexes are omitted to enhance clarity. All proofs are discussed in Appendix A. As mentioned in [54] and [55], constraints that do not link the agents' productions do not affect the proofs, as they leave the market-clearing conditions unchanged.

In each model, the original equilibrium problem is reformulated as an equivalent optimization problem. As discussed in [53], the objective function of these optimization problems is a fictitious function that resembles a social welfare maximization, but is adjusted to incorporate quadratic terms that capture the welfare loss resulting from the Cournot distortion due to the market power exerted by agent.

3.1. Joint Cournot model without SMs

The base model presented in this section serves for comparative analysis for the subsequent extensions) and is based on [50] and [52]. Note that this formulation excludes the HPA and employs a modified notation to ensure consistency with the extensions.

In the resulting Cournot competition, each agent e strategically decides its electricity (q_e), green hydrogen (q_e^{CH2}) and gray hydrogen (q_e^{NH2}) productions to maximize its profit, i.e.:

$$\max_{q_e, q_e^{CH2}, q_e^{NH2}} \{b_e(q_e, p) + b_e^{H2}(q_e^{CH2}, q_e^{NH2}, p, p^{H2})\} \quad \forall e \tag{1}$$

Here q_e^{CH2} denotes green hydrogen production from grid electricity ($q_e^{H2,grid}$) and from RE PPAs ($Q_e^{H2,PPA}$), i.e.:

$$q_e^{CH2} = q_e^{H2,grid} + Q_e^{H2,PPA} \tag{2}$$

For simplicity, and without compromising the mathematical proofs, the formulation presented here intentionally omits production from DC facilities ($q_e^{H2,DC}$). Section 4 will extend this formulation to include it.

The profit b_e from participating in the electricity sector equals the revenues from the wholesale market and from physical PPAs minus the production costs:

$$b_e(q_e, p) = p \cdot \left(q_e - Q_e^{PPA,s}\right) + L_e^{PPA,s} \cdot Q_e^{PPA,s} - c_e(q_e) \tag{3}$$

The first term represents market revenues from the volume $q_e - Q_e^{PPA,s}$ allocated to satisfy the wholesale demand, d^w, paid at the marginal electricity market price p. The second term corresponds to the PPA revenues, where $L_e^{PPA,s}$ is the PPA price and $Q_e^{PPA,s}$ the contracted quantity. The last term accounts for the total electricity production costs, c_e.

The profit b_e^{H2} from the hydrogen sector equals the revenues from the wholesale hydrogen market minus the cost for producing both green and gray hydrogen:

$$\begin{aligned} b_e^{H2}(q_e^{CH2}, q_e^{NH2}, p, p^{H2}) & \\ &= p^{H2} \cdot (q_e^{CH2} + q_e^{NH2}) - c_e^{CH2}(q_e^{CH2}, p) \\ &- c_e^{NH2}(q_e^{NH2}) \end{aligned} \tag{4}$$

The first term is the revenue from selling hydrogen at the marginal hydrogen market price p^{H2}. The second and third terms represent the costs of green, c_e^{CH2}, and gray hydrogen, c_e^{NH2}, respectively. Note that green hydrogen costs, c_e^{CH2}, depend on electricity price p, which is the main linking condition between both sectors' profit functions, as follows:

$$c_e^{CH2}\left(q_e^{CH2,S}, p\right) = p \cdot \eta^{-1} \cdot (q_e^{CH2}) + L_e^{H2,PPA} \cdot \eta^{-1} \cdot Q_e^{H2,PPA} \tag{5}$$

The Cournot game includes the following market-clearing constraints:

$$\begin{aligned} q_e + q_{-e} = d^w(p) + Q_e^{PPA,s} + Q_{-e}^{PPA,s} + \eta^{-1} \cdot (q_e^{H2,grid} \\ + q_{-e}^{H2,grid}) \end{aligned} \tag{6}$$

$$q_e^{CH2} + q_{-e}^{CH2} + q_e^{NH2} + q_{-e}^{NH2} = d^{w,H2}(p^{H2}) \tag{7}$$

Equation (6) ensures that electricity production meets the wholesale electricity demand d^w, PPAs and the electrolyzers consuming from the grid. Similarly, (7) ensures that the total hydrogen production satisfies the wholesale hydrogen demand $d^{w,H2}$.

Electricity and hydrogen demands are assumed to be price-elastic and have been modeled using linear functions:

$$d^w(p) = D_0^w - \alpha_0^w \cdot p \tag{8}$$

$$d^{w,H2}(p^{H2}) = D_0^{w,H2} - \alpha_0^{w,H2} \cdot p^{H2} \tag{9}$$

Here, D_0^w and $D_0^{w,H2}$ are the demand intercepts, while α_0^w and $\alpha_0^{w,H2}$ the corresponding price slopes.

As can be proved (see corollary I of Appendix A.), the Cournot equilibrium problem defined by (1) subject to (2), (6) and (7) can be solved with the following equivalent quadratic optimization model:

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$$\min_{q,q^{CH2},q^{NH2},d^w,d^{w,H2}} \sum_e \Big(c_e(q_e) + c_e^{NH2}(q_e^{NH2}) + \frac{\theta_0^w}{2} \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot q_e^{CH2}\right)^2 + \frac{\theta_0^{w,H2}}{2} \cdot (q_e^{CH2} + q_e^{NH2})^2\Big) + \frac{(D_0^w - d^w)^2}{2 \cdot \alpha_0^w} + \frac{\left(D_0^{w,H2} - d^{w,H2}\right)^2}{2 \cdot \alpha_0^{w,H2}} \tag{10}$$

s.t. (2) and:

$$q_e + q_{-e} = d^w + \eta^{-1} \cdot (q_e^{H2,grid} + q_{-e}^{H2,grid}) + Q_e^{PPA,s} + Q_{-e}^{PPA,s} \quad :\mu \tag{11}$$

$$q_e^{CH2} + q_{-e}^{CH2} + q_e^{NH2} + q_{-e}^{NH2} = d^{w,H2} \quad :\mu^{H2} \tag{12}$$

Being $\theta_0^w = 1/\alpha_0^w$ and $\theta_0^{w,H2} = 1/\alpha_0^{w,H2}$ the so-called Cournot conjectures in the electricity and hydrogen markets respectively, which are related to the market power of the agents in each market [56]. In this formulation, d^w and $d^{w,H2}$ are decision variables instead of functions as they were in (8) and (9) for the Cournot game. Furthermore, it is proved that the dual variables μ and μ^{H2} do correspond to the marginal prices p and p^{H2}.

3.2. Joint Cournot model with fixed premium SM

When a fixed premium SM is considered, green hydrogen producers receive an additional payment per unit produced, on top of the wholesale market price. The type of premium modeled is based on the one from the European Hydrogen Bank (EHB) [57], where each producer is granted a specific quantity of hydrogen eligible for the premium. This allocated quantity is determined through the competitive bidding process (auction) and corresponds to the maximum subsidized volume.

Therefore, the premium is capped at a maximum annual quantity for each producer, so total hydrogen production is split into subsidized ($q_e^{CH2,S}$) and not subsidized ($q_e^{CH2,NS}$) green hydrogen productions, i.e.:

$$q_e^{CH2} = q_e^{CH2,S} + q_e^{CH2,NS} \tag{13}$$

The annual amount of subsidized hydrogen for each agent is limited by their maximum subsidized production, $Q_e^{CH2,S}$:

$$q_e^{CH2,S} \leq Q_e^{CH2,S} \tag{14}$$

As a result, the hydrogen sector profit function formulated in (4) is modified to include the fixed premium as follows:

$$b_e^{H2}\left(q_e^{CH2,S}, q_e^{CH2,NS}, q_e^{NH2}, p, p^{H2}\right) = (p^{H2} + FP^{H2}) \cdot q_e^{CH2,S} + p^{H2} \cdot \left(q_e^{CH2,NS} + q_e^{NH2}\right) - c_e^{CH2}\left(q_e^{CH2,S} + q_e^{CH2,NS}, p\right) - c_e^{NH2}(q_e^{NH2}) \tag{15}$$

where FP^{H2} is the fixed premium per unit of subsidized green hydrogen. As in (15) the market-clearing constraints (6) and (7) must consider (13) to set apart subsidized and non-subsidized hydrogen, and (14) to set the maximum subsidized production.

As can be proved (see corollary II of Appendix A.), the resulting Cournot equilibrium defined by (1), (3) and (15), subject to (2), (6), (7), (13) and (14) can be solved with the following quadratic optimization model:

$$\min_{q,q^{CH2,S},q^{CH2,NS},q^{NH2},d^w,d^{w,H2}} \sum_e \Big(c_e(q_e) + c_e^{NH2}(q_e^{NH2}) + \frac{\theta_0^w}{2} \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right)^2 + \frac{\theta_0^{w,H2}}{2} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} + q_e^{NH2}\right)^2 - FP^{H2} \cdot q_e^{CH2,S}\Big) + \frac{(D_0^w - d^w)^2}{2 \cdot \alpha_0^w} + \frac{\left(D_0^{w,H2} - d^{w,H2}\right)^2}{2 \cdot \alpha_0^{w,H2}} \tag{16}$$

subject to the linking constraints (11) and (12), and the non-linking constraints (2), (13) and (14). Again, the dual variables μ and μ^{H2} correspond to the marginal prices p and p^{H2}.

3.3. Joint Cournot model with PhOT SM

In a government PhOT scheme, the producer and the government establish a bilateral agreement with predefined price and quantity (i.e.: an HPA where the government acts as the buyer). As in [52], the profit for hydrogen producers becomes:

$$b_e^{H2}(q_e^{CH2}, q_e^{NH2}, p, p^{H2}) = P^{HPA} \cdot Q_e^{HPA} + p^{H2} \cdot (q_e^{CH2} + q_e^{NH2} - Q_e^{HPA}) - c_e^{CH2}(q_e^{CH2}, p) - c_e^{NH2}(q_e^{NH2}) \tag{17}$$

The term $P^{HPA} \cdot Q_e^{HPA}$ is the revenue guaranteed by the government off-take, where P^{HPA} is the agreed price and Q_e^{HPA} the volume set. Note that both volume and price set in the agreement are known beforehand. On the other hand, the term $p^{H2} \cdot (q_e^{CH2} + q_e^{NH2} - Q_e^{HPA})$ is the income from the hydrogen market where $q_e^{CH2} + q_e^{NH2} - Q_e^{HPA}$ represent the production sold.

While the market-clearing constraint for the electricity sector (6) is not modified, the one for the hydrogen sector must now consider the HPA contracts, thereby:

$$q_e^{CH2} + q_{-e}^{CH2} + q_e^{NH2} + q_{-e}^{NH2} = d^{w,H2}(p^{H2}) + Q_e^{HPA} + Q_{-e}^{HPA} \tag{18}$$

Additionally, (19) imposes that the HPAs are met with green hydrogen production:

$$q_e^{CH2} \geq Q_e^{HPA} \tag{19}$$

In this case, the Cournot equilibrium defined by (1), (3) and (17) subject to (2), (6), (18) and (19) can be solved using the following quadratic optimization problem (see corollary III of Appendix A.):

$$\min_{q,q^{CH2},q^{NH2},d^w,d^{w,H2}} \sum_e \Big(c_e(q_e) + c_e^{NH2}(q_e^{NH2}) + \frac{\theta_0^w}{2} \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot q_e^{CH2}\right)^2 + \frac{\theta_0^{w,H2}}{2} \cdot (q_e^{CH2} + q_e^{NH2} - Q_e^{HPA})^2\Big) + \frac{(D_0^w - d^w)^2}{2 \cdot \alpha_0^w} + \frac{\left(D_0^{w,H2} - d^{w,H2}\right)^2}{2 \cdot \alpha_0^{w,H2}} \tag{20}$$

subject to:

$$q_e^{CH2}+q_{-e}^{CH2}+q_e^{NH2}+q_{-e}^{NH2}=d^{w,H2}+Q_e^{HPA}+Q_{-e}^{HPA}\quad :\mu^{H2} \tag{21}$$

And also to the linking constraint (11), and the non-linking constraints (6) and (19). Again, the dual variables μ and μ^{H2} correspond to the marginal prices p and p^{H2}.

3.4. Joint Cournot model with FinOT SM

In a government FinOT scheme, support is provided through a CfD without physical transaction. In this case, apart from the operation in the wholesale hydrogen market, hydrogen producers can contract a predefined volume $Q_e^{CH2,off}$ of green hydrogen which is settled with the government at price $(P^{off}-p^{H2})$ where P^{off} is the strike price of the CfD. If a symmetric CfD design is assumed, then the producer receives compensation if $P^{off}\geq p^{H2}$ but must reimburse the difference if $P^{off}<p^{H2}$. Then, the profit function of the hydrogen producers becomes:

$$\begin{aligned}b_e^{H2}(q_e^{CH2},q_e^{NH2},p,p^{H2})\\ &=(P^{off}-p^{H2})\cdot Q_e^{CH2,off}+p^{H2}\\ &\cdot(q_e^{CH2}+q_e^{NH2})-c_e^{CH2}(q_e^{CH2},p)\\ &-c_e^{NH2}(q_e^{NH2})\end{aligned} \tag{22}$$

Contrary to the PhOT, linking constraints (6) and (7) are not modified since CfD do not entail physical delivery of hydrogen. The following quadratic optimization problem can be solved to obtain the Cournot equilibrium defined by (1), (3) and (22) and subject to (2), (6) and (7) (see corollary IV of Appendix A.):

$$\begin{aligned}\min_{q,q^{CH2},q^{NH2}d^w,d^{w,H2}}\sum_e\Bigg(c_e(q_e)+c_e^{NH2}(q_e^{NH2})+\frac{\theta_0^w}{2}\\ \cdot\left(q_e-Q_e^{PPA,s}-\eta^{-1}\cdot q_e^{CH2}\right)^2+\frac{\theta_0^{w,H2}}{2}\\ \cdot\left(q_e^{CH2}-Q_e^{H2,off}+q_e^{NH2}\right)^2\Bigg)\\ +\frac{(D_0^w-d^w)^2}{2\cdot\alpha_0^w}+\frac{\left(D_0^{w,H2}-d^{w,H2}\right)^2}{2\cdot\alpha_0^{w,H2}}\end{aligned} \tag{23}$$

Constraints (2), (11) and (12) also must hold. Dual variables of these last two constraints are also the marginal prices in each market.

3.5. Joint Cournot model with national quota schemes

Under a national-level quota scheme, the requirement acts as a regulatory constraint, setting a minimum production floor for green hydrogen. Note that this quota does not involve any direct governmental remuneration or subsidy for the volume produced. Consequently, each producer must meet a minimum production target for green hydrogen denoted by Q_e^{CH2}:

$$\sum_{h\epsilon y}q_{eh}^{CH2}\geq Q_e^{CH2} \tag{24}$$

In this case, the objective functions (3) and (4) along with the linking constraints (6) and (7) that define the Cournot game set in (1) without SMs, remain unchanged. As a result, the optimization problem defined in (10) subject to (2), (11), (12) and (24) can still be used to obtain an equilibrium.

4. Model extension

This section presents additional non-linking constraints incorporated into the model. As mentioned in [54] and [55], these constraints (as well as (2), (14), (19) and (24)) do not affect the proofs that the equilibrium models in the previous section can be solved with the corresponding equivalent quadratic optimization problems, as they leave the market-clearing conditions unchanged. In this section, time-related and technological (thermal power plants, hydro units, etc.) indexes are included only when needed to enhance clarity.

4.1. Hydrogen sector constraints

4.1.1. Hydrogen logical constraints

Equations (25), (26), and (27) describe the allocation and use of RE for each hour h, and RE technology j:

$$Q_{ejh}=q_{ejh}+s_{ejh} \tag{25}$$

$$q_{ejh}\geq\eta^{-1}\cdot q_{ejh}^{H2,grid}+Q_{ejh}^{PPA,s} \tag{26}$$

$$s_{ejh}\leq Q_{ejh}-\eta^{-1}\cdot q_{ejh}^{H2,grid} \tag{27}$$

Equation (25) ensures that the total available RE, Q_{ejh}, is either used for electricity (for meeting wholesale electricity demand or electrolyzers consumption), q_{ejh}, or curtailed, s_{ejh}. Equation (26) guarantees that there is sufficient RE to meet both the consumption of electrolyzers connected to the grid ($\eta^{-1}\cdot q_{ejh}^{H2,grid}$) and any pay-as-produced PPA ($Q_{ejh}^{PPA,s}$). Since PPAs are paid according to actual production, producers always have enough RE to fulfill these contracts. Equation (27) further ensures that hydrogen production utilizes RE that would otherwise be curtailed.

Temporal correlation is ensured since (25), (26) and (27) are set on an hourly basis, and geographical correlation is implemented for a single-node area without cross-border interconnections, as discussed in [52].

Note that this formulation satisfies the additionality criterion in terms of efficient use of RE only when curtailment is reduced by the hydrogen production. However, they do not necessarily prevent hydrogen from competing with conventional electricity demand, nor does it guarantee that overall system emissions are not unaffected.

4.1.2. DC Green hydrogen constraints

For hydrogen produced under DC approach, the available RE at the corresponding facility, Q_{ej}^{DC}, is allocated to three possible uses: feeding the electrolyzer $\eta^{-1}\cdot q_{ej}^{H2,DC}$, producing electricity for the wholesale market, q_{ej}^{DC}, or being spilled as unused energy s_{ej}^{DC}

$$Q_{ej}^{DC}=\eta^{-1}\cdot q_{ej}^{H2,DC}+q_{ej}^{DC}+s_{ej}^{DC} \tag{28}$$

In addition, the total green hydrogen production must be limited by the electrolyzer capacity considering its efficiency:

$$q_e^{CH2}\leq\eta\cdot CAP_e^{CH2} \tag{29}$$

4.1.3. Hydrogen storage constraints

The following constraints are applied to hydrogen storage:

$$loh_{evh}^{H2}=loh_{evh-1}^{H2}+\eta^{ch,H2}\cdot b_{evh}^{H2}-\frac{q_{evh}^{H2}}{\eta^{dis,H2}}-q_{evh}^{H2,loss} \tag{30}$$

Equation (30) governs the level of hydrogen (LoH) in the vessel, loh_{evh}^{H2}, by relating it to the LoH in the previous hour, loh_{evh-1}^{H2}. considering the charge b_{evh}^{H2} and discharge q_{evh}^{H2} of the tank. accounting for their respective efficiencies, $\eta^{ch,H2}$ for the charge and $\eta^{dis,H2}$ for the discharge as well as the tank losses, $q_{evh}^{H2,\text{loss}}$.

$$b_{evh}^{H2}\leq CAP_{ev}^{H2} \tag{31}$$

$$q_{evh}^{H2}\leq CAP_{ev}^{H2} \tag{32}$$

$$LOH_{ev}^{min,H2}\leq loh_{evh}^{H2}\leq LOH_{ev}^{MAX,H2} \tag{33}$$

Additionally, both charge and discharge are limited by the capacity of the tank, CAP_{ev}^{H2} as shown in (31) and (32) while (33) limits the LOH between its minimum, $LOH_{ev}^{\min,H2}$, and maximum, $LOH_{ev}^{MAX,H2}$. Losses in the tank are represented as a linear function, as per in [58]:

$$q_{evh}^{H2,loss} = \varepsilon \cdot loh_{evh-1}^{H2} \tag{34}$$

where ε represents the loss factor.

4.1.4. Green hydrogen portfolio constraints

Total green hydrogen production for each agent e can be expressed as:

$$q_e^{CH2} = q_e^{H2,grid} + Q_e^{H2,PPA} + q_e^{H2,DC} + \sum_v (q_{ev}^{H2} - b_{ev}^{H2}) \tag{35}$$

- The first term represents the green hydrogen produced consuming electricity from the grid, $q_e^{H2,grid}$ (reducing curtailment approach).
- The second term accounts for the green hydrogen produced consuming electricity supplied under a PPA, $Q_e^{H2,PPA}$ (PPA approach).
- The third term refers to green hydrogen production in a dedicated RE facility, $q_e^{H2,DC}$ (DC approach).
- The last term represents the green hydrogen q_{ev}^{H2} extracted from the tank minus the hydrogen b_{ev}^{H2} stored.

4.2. Electricity sector constraints

In the electricity sector, the only additional constraints introduced in this work are those related to the battery storage, all other constraints (unit commitment, hydro dispatch, etc.) are detailed in in [50].

4.2.1. Batteries constraints

Departing from the model described in in [50], the following electricity storage constraints have been included: in the models:

$$soc_{esh} = soc_{esh-1} + \eta^{ch} \cdot b_{esh} - \frac{q_{esh}}{\eta^{dis}} \tag{36}$$

Equation (36) controls the state-of-charge (SoC), soc_{esh}, of the battery facility, relating it to the SoC in the previous hour, soc_{esh-1}, considering the charge b_{esh} and discharge q_{esh} and accounting for the corresponding efficiency: η^{ch} for the charge and η^{dis} for the discharge.

Additionally, both charge and discharge are limited by the capacity of the battery, CAP_{es}, as seen in (37) and (38). Similarly, (39) limits the SoC through minimum and maximum bounds:

$$ch_{esh} \leq CAP_{es} \tag{37}$$

$$q_{esh} \leq CAP_{es} \tag{38}$$

$$SOC_{es}^{min} \leq soc_{esh} \leq SOC_{es}^{MAX} \tag{39}$$

4.2.2. Portfolio constraints

Total electricity generation, q_e, is given by:

$$q_e = \sum_j (q_{ej} + q_{ej}^{DC}) + \sum_t q_{et} + \sum_u (q_{eu} - b_{eu}) + \sum_s (q_{es} - b_{es}) + \sum_o q_{eo} \tag{40}$$

- The first term represents the electricity production q_{ej} from solar and wind technologies, including the energy q_{ej}^{DC} from DC facilities.
- The second term accounts for thermal power plants production q_{et}.
- The third includes hydro production q_{eu} considering the energy pumped b_{eu}.
- The fourth term represents the energy discharged q_{es} from batteries minus the energy charged b_{es}.
- The last term includes the production q_{eo} from other technologies (nuclear, biomass, solar thermoelectric, small hydro, etc.).

5. Case studies

The case studies simulate a hypothetical Iberian 2030 scenario where the power systems represented are basically based on the descriptions found in the Spanish and Portuguese National Energy and Climate Plans (NECP) [59], [60] and where an organized hydrogen market is in place. The goal is to assess how the different SMs for green hydrogen production studied in this paper, as well as the relaxation of the additionality requirement, influence the joint dispatch of the electricity and hydrogen sectors. To do so, different configurations are considered:

- No subsidies *(NoSub)*: section 3.1 model with no SMs. This case is used as a benchmark for comparisons.
- Relaxing additionality *(RA)*: section 3.1 model, but excluding the additionality criteria imposed by constraints (26) and (27). Although it is not a SM per se, relaxing such constraints may boost green hydrogen production by simplifying the green condition requirements.
- Fixed premium *(FP)*: section 3.2 model, that considers a fixed premium subsidy.
- Physical off-take *(PhOT)*: section 3.3 model, that considers a government-backed physical off-take agreement.
- Financial off-take *(FinOT)*: section 3.4 model, that considers a government-backed financial contract.
- *Quota*: section 3.5 model, that imposes a mandatory green hydrogen quotal.

The model was implemented in GAMS v46.1.0 and solved with CPLEX 22.1.1.0 on an Intel i7-8700 CPU (3.20 GHz) with 64 GB RAM, using 11 threads. Each run comprises around 4.8 million continuous variables and 2.8 million equations. The average execution time was about 30 minutes, with 5 minutes for the solver and the remainder for pre- and post-processing tasks such as data loading, scaling, and output parameter calculation.

5.1. Input data

Fuel costs, capacities, and other relevant technical parameters can be found in Appendix B. The conversion from energy units to hydrogen mass was performed using the lower heating value (LHV) of hydrogen (33.33 MWh/ton H_2) [61]. Data regarding agents' electrolyzers portfolio presented in [52] were updated using the data from [62], [63] and [64]. Other system data were obtained from the Spanish and Portuguese NECPs, [59] and [60].

Regarding the SMs, data (i.e.: the fixed premium and the volumes in the physical and financial off-takes and quota) were drawn from the European Hydrogen Bank's Innovation Fund auction [65], which granted a fixed premium with an average value of 0.52 €/kg H_2 for a total volume of 2.2 Mton over 10 years. This corresponds to approximately 0.22 Mton per year linked to the 2.33 GW of electrolyzer capacity supported in the auction. For the purposes of the case studies, this volume was rescaled proportionally to the installed capacity in the study year (15.33 GW), resulting in a total subsidized volume Q^{CH2} =1.45 Mton. The average premium was assumed to be the same for all agents, i.e. FP^{H2}= 0.52 €/kg H_2.

To distribute the annual volume of hydrogen, Q^{CH2}, among agents for each SM (i.e.: $Q_e^{CH2,S}$ for the fixed premium, Q_e^{HPA} for the physical offtake, $Q_e^{CH2,off}$ for the financial offtake, and Q_e^{CH2} for the quota), each agent's share, X_e^{CH2}, was computed based on their electrolyzer capacity, CAP_e^{CH2}, relative to the total installed capacity:

$$X_e^{CH2} = \frac{CAP_e^{CH2}}{\sum_{e'} CAP_{e'}^{CH2}} \tag{41}$$

Finally, for both PhOT and FinOT mechanisms, a constant hourly volume was assumed, calculated by dividing the yearly amount, X_e^{CH2}, by the 8760 hours of the year.

5.2. Results and discussion

Table 3 summarizes the main system results across the different cases:

Table 3. Main system results

Iberian system, 20230	No subsidies (NoSub)	Relaxing additionality (RA)	Fixed Premium (FP)	Physical off-take (PhOT)	Financial off-take (FinOT)	Quota
Electricity balance (TWh)						
Total demand	296.8	296.6	297.4	300.9	299.8	299.8
Wholesale demand	166.7	164.7	164.7	162.6	162.6	162.3
PPAs	94	94	94	94	94	94
Grid electrolysis	36.1	37.8	38.7	44.3	43.2	43.5
Combined cycle gas turbines plants	3.8	3.7	4.4	5.4	5.2	5.1
Batteries discharge	2.3	2.2	2.4	2.5	2.5	2.5
Batteries charge	-2.9	-2.8	-2.9	-3.1	-3.0	-3.1
RE production for electricity sector	194.9	194.8	195.0	197.5	196.6	196.7
Existing RE production	193.7	193.4	194.2	195.9	195.5	196.3
RE from DC facilities	1.2	1.4	0.7	1.6	1.0	0.3
Others (nuclear, hydro, etc.)	98.6	98.6	98.6	98.6	98.6	98.6
Hydrogen balance (Mton)						
Demand	2.23	2.26	2.3	2.41	2.40	2.42
Wholesale demand	2.23	2.26	2.3	0.96	2.40	2.42
Government off-take	-	-	-	1.45	-	-
Green H2 production	1.44	1.48	1.52	1.63	1.62	1.64
Green H2 from grid	0.85	0.89	0.91	1.05	1.02	1.03
Green H2 from PPAs	0.23	0.23	0.23	0.23	0.23	0.23
Green H2 from DC	0.37	0.36	0.38	0.36	0.37	0.39
Green H2 from storage	0.27	0.31	0.27	0.29	0.28	0.30
Green H2 stored	-0.29	-0.33	-0.28	-0.30	-0.30	-0.32
Gray H2	0.80	0.80	0.80	0.80	0.80	0.80
RE allocation (existing and from DC plants) (TWh)						
Total available RE	317.4	317.4	317.4	317.4	317.4	317.4
Total usage	210.6	210.3	211.1	212.8	212.4	213.2
Existing RE for wholesale electricity demand	63.6	61.6	61.5	57.6	58.3	58.8
RE from DC facilities for wholesale electricity demand	1.2	1.4	0.7	1.6	1.0	0.3
RE for PPA	94.0	94.0	94.0	94.0	94.0	94.0
Electrolyzers consumption from grid	36.1	37.8	38.7	44.3	43.2	43.5
Electrolyzers consumption from DC	15.6	15.5	16.1	15.2	15.8	16.5
Spillages (self-curtailment)	106.8	107.1	106.3	104.6	105.0	104.2
Annual average price						
Electricity price (€/MWh)	96.7	97.3	97.3	97.9	97.9	98.0
Hydrogen price (€/kg)	5.39	5.30	5.2	4.91	4.94	4.88
Unitary H2 production costs (€/kg)						
Green hydrogen (weighted average)	2.53	2.57	2.59	2.76	2.72	2.69
Green H2 from grid	3.93	3.92	3.97	4.01	4.01	3.99
Green H2 from PPAs	1.36	1.36	1.36	1.36	1.36	1.36
Green H2 from DC	0.00	0.00	0.00	0.00	0.00	0.00
Gray hydrogen	2.89	2.89	2.89	2.89	2.89	2.89
Absolute production costs (M€)						
Total	6509	6651	6859	7545	7420	7421
Electricity sector	545	531	611	731	709	701
Hydrogen sector	5964	6120	6248	6814	6710	6720
Absolute emissions (Mton CO2)						
Total	8.30	8.26	8.52	8.92	8.85	8.82

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Electricity sector	**1.52**	**1.47**	**1.74**	**2.14**	**2.07**	**2.04**
Hydrogen sector	**6.78**	**6.78**	**6.78**	**6.78**	**6.78**	**6.78**
Carbon intensity						
Electricity sector (kg CO2/MWh)	**9.12**	**8.95**	**10.57**	**13.16**	**12.72**	**12.57**
Hydrogen sector (kg CO2/kg H2)	**3.04**	**3.00**	**2.95**	**2.81**	**2.82**	**2.80**

Several conclusions can be drawn from these results. From the electricity balance table entry:

- Subsidies increase total electricity demand by stimulating electrolyzers consumption. This increased electricity demand is met by RE production, Combined Cycle Gas Turbines (CCGTs), and, to a lesser extent, battery storage. The only exception is RA case, where total demand slightly decreases compared to the base case (NoSub) This occurs because, in the absence of additionality restrictions constraints (25)-(27), agents are no longer forced to use more of their available RE

From the RE allocation table entry:

- Support mechanisms increase total renewable energy (RE) utilization by reducing spillages relative to the reference scenario. Total RE production includes both existing RE not directly connected to an electrolyzer and RE from DC sources directly connected to an electrolyzer, which can be allocated either to hydrogen production or to the electricity market. The only exception is the RA case, which exhibits a slight decrease of 0.3 TWh relative to the base case. This occurs because the additionality constraints (25)-(27), do not apply, and agents are therefore not required to increase RE usage compared to scenarios where additionality is enforced.
- It can also be seen that support mechanisms shift RE production towards hydrogen production, leaving less to meet wholesale electricity demand. This shift is larger in mechanisms designed to cover volume risk (PhOT, FinOT, and Quota), which increase electrolyzer consumption by approximately 7.8 TWh while reducing RE for wholesale demand by about 5.6 TWh.
- Furthermore, under Cournot competition, market participants strategically withhold available RE through self-curtailment in order to restrict supply and artificially increase electricity prices [66], [67]. As noted in [50], such imperfect competition can lead to massive amounts of spilled energy, (over 100TWh as seen in Table 3). By contrast, in a more competitive market, an increase in electrolyzer demand would ideally be met by reducing existing RE spillages, rather than by displacing supply from the wholesale electricity market, as discussed in [50]. However, under imperfect competition, market agents seek to increase their profits by reallocating RE. They do so by diverting RE generation from the wholesale electricity market to hydrogen production, which reduces electricity supply and creates market inefficiencies.

When looking at the hydrogen balance entry:

- Subsidies successfully stimulate green hydrogen production, which grows from 1.44 Mton (NoSub) to a peak of 1.64 Mton (Quota), and slightly increase hydrogen storage utilization.
- The growth in total hydrogen demand is supplied almost entirely with grid electrolysis, as production from PPAs and DC facilities remains limited by contracts or RE resource availability.
- Wholesale hydrogen demand increases in all cases, except in the PhOT scenario where wholesale hydrogen demand drops significantly because a large portion is sold through the government off-take agreement out of the wholesale market.

Regarding prices table entry:

- Subsidies lower hydrogen prices, which in turn stimulates demand. This result is a positive effect since incentives like the Fixed Premium and those designed to cover volume-risk (PhOT, FinOT, and Quota) aim to make hydrogen more competitive. The price reduction is also consistent with the first-order Conditions in Appendix A. , where increasing subsidy parameters reduces the term $\theta_0^{w,H2} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right)$, and so the hydrogen price.
- The hydrogen price reduction is also driven by more strategic behavior in grid-connected electrolysis in response to electricity prices. To illustrate this, Figure 2, shows the average level of electrolytic hydrogen production from the grid across low-, medium-, and high-price electricity hours. In all scenarios, production is concentrated during low-price periods. However, this pattern becomes more pronounced when support mechanisms are introduced. For instance, under the "No subsidies" scenario, average hydrogen production during low-price hours is 134 tons. When subsidies are considered, this value increases, reaching up to 160 tons.

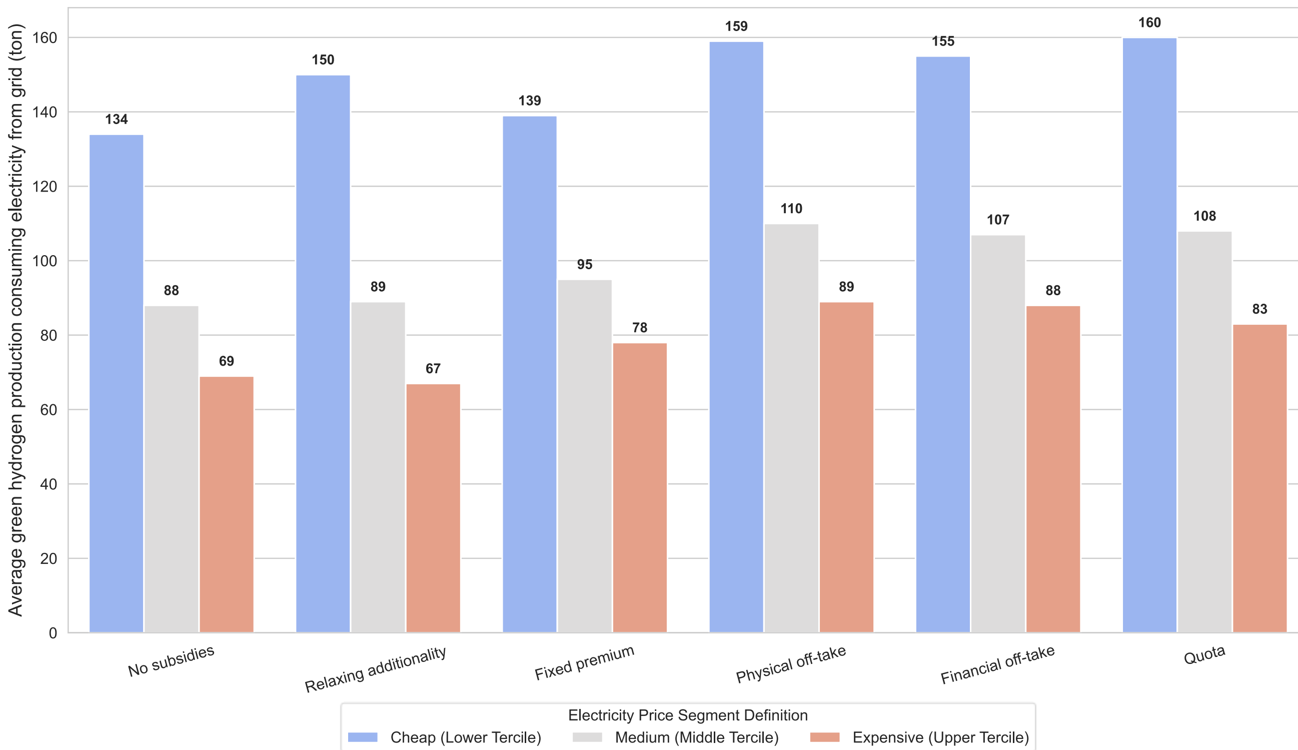

Figure 2. Average green hydrogen production consuming electricity from grid with respect to the electricity price distribution

Regarding the hydrogen production table entry:

- Gray hydrogen production remains constant at 0.8 Mton across all scenarios. Indeed, despite incentives, green hydrogen from PPA and DC are upper bounded, and, to meet demand, can only be complemented by green hydrogen from the grid which is more expensive, ranging from 3.93 to 4.01 €/kg compared to 2.89 €/kg for gray hydrogen.
- However, in all cases the cost of the production-weighted average green hydrogen, including all production alternatives, is competitive (2.57-2.76 €/kg) with gray hydrogen. This suggests that policies could focus on promoting DC facilities and new PPAs for hydrogen production, which would entail two additional benefits: increasing green production and lowering its average cost, which could help displacing gray hydrogen and reduce emissions.

Regarding the economic table entry:

- All support mechanisms increase total production costs (note that subsidy costs are not included). In the electricity sector, costs rise due to increased demand for hydrogen production, met by CCGT plants, while in the hydrogen sector, higher electricity prices increase hydrogen production costs. Therefore, regulators should assess whether the benefits of subsidies (such as accelerating hydrogen production maturity) outweigh not only the additional system costs but also the cost of implementing these subsidies. This is particularly relevant for schemes such as physical off-take, where governments directly purchase green hydrogen, increasing public expenditure. Within the scope of this paper, the cost of support mechanisms that address volume risk cannot be directly quantified due to missing information on off-take prices, such as the strike price in the *FinOT* or the purchase price in the *PhOT*. By contrast, the *Quota* case does not involve direct costs, although it may create indirect costs for off-takers forced to consume green hydrogen, who may pass the additional cost on to consumers.

Finally, regarding the environmental table entries:

- Larger hydrogen demand requires additional CCGT production and therefore larger CO_2 emissions in the electricity sector. In contrast, absolute emissions in the hydrogen sector remain constant because gray hydrogen production, the primary source of pollution, does not change.
- However, the carbon intensity of hydrogen production decreases as total demand grows. While the carbon intensity of the electricity sector rises under subsidies, it remains moderately low, ranging between 10.57 and 13.16 kg CO_2/MWh, compared to approximately 100 kg CO_2/MWh registered in Spain in 2024 [68]. These values are well below the EU threshold of 65 kg CO_2/MWh required for hydrogen to be certified as green, suggesting that if NECP targets are met, strict additionality or temporal correlation requirements may not be necessary. Therefore, a more flexible regulatory approach could be considered without compromising environmental goals.

In summary, these results illustrate a clear trade-off: while support mechanisms successfully drive green hydrogen adoption and lower prices, they also trigger higher emissions and prices in the power sector. This suggests that complementary policies might be considered to meet hydrogen demand without increasing reliance on fossil fuels.

5.3. Performance indicators

In order to provide a comprehensive comparison of the subsidies analyzed, Figure 3 displays a radar chart summarizing the performance

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indicators relative to the reference case (*NoSub*). These metrics aim to assess the impact on the main stakeholders:

- Consumers: electricity and hydrogen prices.
- System operator: total electricity and hydrogen sector production costs.
- Companies: electricity and hydrogen sector profits.
- Policymakers: green hydrogen production and total emissions.

Details regarding the economic results are provided in Appendix C. Normalized values are calculated such that any score above 100 represents an improvement relative to the reference case:

- For indicators where higher values represent improvement (e.g., profits and green hydrogen production), the value is the ratio between the SM value and the reference case value.
- For indicators where lower values represent improvement (e.g., prices, costs, and emissions), the value is the inverse of the ratio.

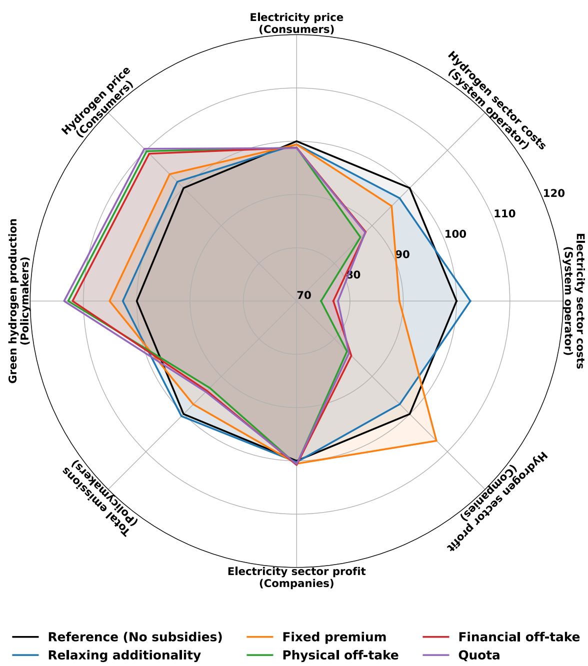

Figure 3. Performance indicators radar chart

The analysis of the radar chart reveals that no SM benefits all stakeholders simultaneously:

- From the consumers' perspective, Hydrogen prices decrease across all scenarios, particularly under volume-risk mechanisms (PhOT, FinOT, and Quota), while electricity prices slightly increase in all cases.
- For the system operators, hydrogen costs rise in all cases due to higher green hydrogen production and increased electricity prices for hydrogen. consuming electricity from the grid. Electricity costs are slightly reduced only in the *Relaxing additionality* case, while the rest of the case are increased since the additional demand is met with thermal units.
- From the companies' perspective, electricity profits are almost unaffected, but hydrogen profits generally decline due to lower prices and higher costs. The exception is the *FP*, which directly increases hydrogen producers' revenues due to the premium itself.
- For policymakers, a trade-off emerges between green hydrogen production and total emissions: higher green hydrogen production leads to higher total emissions. Then, they must assess whether the benefits of green hydrogen adoption (e.g., decarbonizing the steel industry) justify the rise in total emissions.

6. Conclusions

In this paper different joint electricity-hydrogen models under imperfect Cournot competition are proposed to analyze European support mechanisms (SMs) for green hydrogen production. One of the main mathematical contributions is the demonstration that Cournot equilibria, which endogenously captures the influence of electricity prices on green hydrogen production costs, can be computed by solving quadratic optimization models. This approach confirms the potential and versatility of this resolution methodology for large-scale, realistic problems.

The SMs studied address price risk (fixed premium), volume risk (quota) or both (physical and financial off-takes). Hydrogen is produced by consuming grid electricity while reducing RE spillages and improving RE utilization, using RE electricity negotiated through PPAs and from dedicated RE facilities. The paper also explores how relaxing the additionality requirements to label hydrogen as green could act as a SM.

The case studies, implemented on a real-size Iberian system, analyzed the impact of SMs on consumers, companies, and policymakers. The results show that no mechanism simultaneously benefits all stakeholders: consumers benefit from lower hydrogen prices, but this is often accompanied by slightly higher electricity prices. System costs rise in most cases, reflecting both increased electricity demand and the higher cost of green hydrogen production from the grid. For companies, while electricity profits remain unchanged, hydrogen producers generally face declining profits due to lower prices and rising costs, which could negatively affect long-term investment incentives and competitiveness.

Policymakers face a complex trade-off: higher green hydrogen production is associated with higher emissions, even under high RE penetration, due to the partial use of CCGTs to meet increased electricity demand. Additionally, the relaxation of additionality requirements shows that under high RE penetration, the impact on both sectors is limited. This suggests that regulators could reconsider the strictness of such requirements once the NECP targets are achieved, potentially allowing greater flexibility for hydrogen production without compromising decarbonization objectives.

Furthermore, while the analysis demonstrates that support mechanisms present advantages (for instance, the reduction in hydrogen price which boosts demand), a comprehensive assessment requires considering the funding source for these subsidies, which was beyond the scope of this work. The cost of these mechanisms must be financed, and this decision has distributional consequences: while some population segments (e.g., hydrogen consumers) may benefit, others (e.g., taxpayers, if subsidies are funded through taxes) could be negatively affected.

These findings highlight the importance of carefully designing policies that consider intersectoral effects. Mechanisms that reduce hydrogen prices or increase green hydrogen production may create unintended consequences in the electricity sector, such as higher system costs or greater emissions. Intersectoral measures are therefore essential to align the goals of different stakeholders and avoid shifting the burden from one sector to another, possibly through coordinated policy packages combining instruments in both the electricity and hydrogen sectors.

Finally, the study also points to key opportunities for future research. First, the scope of this paper was focused on imperfect competition, but an analysis under perfect competition may yield different results (for instance, under perfect competition, self-curtailment is not possible, which would lead to a better use of the available RE). Second, the analysis should be extended to assess combinations of SMs simultaneously applied in both the electricity and hydrogen sectors, rather than only in the hydrogen sector, exploring balanced measures that mitigate conflicting objectives. Third, future research should extend the scope of hydrogen demand to include its deployment in industrial end-uses (e.g., refining, steel, chemicals) and transport, allowing the willingness-to-pay of different hydrogen consumers to be modeled alongside the environmental impact on different sectors.

Acknowledgements

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Appendix A. Equivalences between the joint Cournot equilibriums and the quadratic optimization problems

Lemma. Let us consider the Cournot where each agent e aims to maximize the following profit $\hat{\boldsymbol{g}}_{\boldsymbol{e}}$:

$$\max_{q_e,q_e^{CH2,S},q_e^{CH2,NS},q_e^{NH2}} \{b_e(q_e,p) + \hat{b}_e^{H2}\left(q_e^{CH2,S}, q_e^{CH2,NS}, q_e^{NH2}, p, p^{H2}; Q_e^{HPA}, Q_e^{CH2,off}\right)\} \quad \forall e \tag{42}$$

where b_e is defined in (3) and:

$$\begin{aligned}\hat{b}_e^{H2}\left(q_e^{CH2,S}, q_e^{CH2,NS}, q_e^{NH2}, p, p^{H2}; Q_e^{HPA}, Q_e^{CH2,off}\right) &= P^{HPA}\cdot Q_e^{HPA} + \left(p^{H2} + FP^{H2}\right)\cdot q_e^{CH2,S} + \left(P^{off} - p^{H2}\right) \\ &\quad \cdot Q_e^{CH2,off} + p^{H2} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} + q_e^{NH2} - Q_e^{HPA}\right) \\ &\quad - c_e^{CH2}\left(q_e^{CH2,S} + q_e^{CH2,NS}, p\right) - c_e^{NH2}\left(q_e^{NH2}\right)\end{aligned} \tag{43}$$

And subject to linking constraints (6) and (18).

Then, the resolution of the following quadratic optimization problem leads to the Cournot equilibrium:

$$\begin{aligned}\min_{q,q^{CH2,S},q^{CH2,NS},q^{NH2},d^w,d^{w,H2}} \sum_e \Bigg(& c_e(q_e) + c_e^{NH2}\left(q_e^{NH2}\right) + \frac{\theta_0^w}{2} \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right)^2 + \frac{\theta_0^{w,H2}}{2} \\ & \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right)^2\Bigg) + \frac{\left(D_0^w - d^w\right)^2}{2\cdot\alpha_0^w} + \frac{\left(D_0^{w,H2} - d^{w,H2}\right)^2}{2\cdot\alpha_0^{w,H2}}\end{aligned} \tag{44}$$

Subject to (11) and (21) with $\theta_0^w = 1/\alpha_0^w$ and $\theta_0^{w,H2} = 1/\alpha_0^{w,H2}$. Moreover, the multipliers μ and μ^{H2} in (11) and (21) correspond to prices p and p^{H2} respectively.

Proof. As in [56], it can be proved that $\frac{\partial p}{\partial q_e} = \mathbf{1/\alpha_0^w}$ and $\frac{\partial p}{\partial q_e^{CH2,S}} = \frac{\partial p}{\partial q_e^{CH2,S}} = \frac{\partial p}{\partial q_e^{NH2}} = \mathbf{1/\alpha_0^{w,H2}}$. Therefore, by nulling the first-order derivatives of the profit functions $\hat{\boldsymbol{g}}_{\boldsymbol{e}}$, we can obtain:

$$\frac{\partial \hat{g}_e}{\partial q_e} = p - \theta_0^w \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1}\cdot\left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right) - c_e'(q_e) = 0 \tag{45}$$

$$\begin{aligned}\frac{\partial \hat{g}_e}{\partial q_e^{CH2,S}} = p^{H2} + FP^{H2} - p\cdot\eta^{-1} - \theta_0^{w,H2} & \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right) + \theta_0^w \cdot \eta^{-1} \\ & \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right) = 0\end{aligned} \tag{46}$$

$$\begin{aligned}\frac{\partial \hat{g}_e}{\partial q_e^{CH2,NS}} = p^{H2} - p\cdot\eta^{-1} - \theta_0^{w,H2} & \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right) + \theta_0^w \cdot \eta^{-1} \\ & \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right) = 0\end{aligned} \tag{47}$$

$$\frac{\partial \hat{g}_e}{\partial q_e^{NH2}} = p^{H2} - \theta_0^{w,H2} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right) - {c'}_e^{NH2}\left(q_e^{NH2}\right) = 0 \tag{48}$$

On the other hand, the Lagrangian function $\mathcal{L}$ of the quadratic optimization problem is:

$$\begin{aligned}\mathcal{L} = \sum_e \Bigg(& c_e(q_e) + c_e^{NH2}\left(q_e^{NH2}\right) + \frac{\theta_0^w}{2} \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right)^2 + \frac{\theta_0^{w,H2}}{2} \\ & \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right)^2\Bigg) + \frac{\left(D_0^w - d^w\right)^2}{2\cdot\alpha_0^w} + \frac{\left(D_0^{w,H2} - d^{w,H2}\right)^2}{2\cdot\alpha_0^{w,H2}} + \mu \\ & \cdot \left(d^w + \eta^{-1}\cdot\left(q_e^{CH2,S} + q_e^{CH2,NS} + q_{-e}^{CH2,S} + q_{-e}^{CH2,NS}\right) + Q_e^{PPA,s} + Q_{-e}^{PPA,s} - q_e - q_{-e}\right) + \mu^{H2} \\ & \cdot \left(d^{w,H2} + Q_e^{HPA} + Q_{-e}^{HPA} - q_e^{CH2,S} - q_e^{CH2,NS} - q_{-e}^{CH2,S} - q_{-e}^{CH2,NS} - q_e^{NH2} - q_{-e}^{NH2}\right)\end{aligned} \tag{49}$$

Thus, its first-order KKT conditions are:

$$\frac{\partial \mathcal{L}}{\partial q_e} = c_e'(q_e) + \theta_0^w \cdot \left(q_e - Q_e^{PPA,s} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right) - \mu = 0 \tag{50}$$

$$\begin{aligned}\frac{\partial \mathcal{L}}{\partial q_e^{CH2,S}} = -\theta_0^w \cdot \eta^{-1} \cdot \Big(q_e - Q_e^{PPA,s} - \eta^{-1} & \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\Big) + \theta_0^{w,H2} \\ & \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right) + \mu\cdot\eta^{-1} - \mu^{H2} - FP^{H2} = 0\end{aligned} \tag{51}$$

$$\frac{\partial \mathcal{L}}{\partial q_e^{CH2,NS}} = -\theta_0^w \cdot \eta^{-1} \cdot \left(q_e - Q_e^{PPA,S} - \eta^{-1} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS}\right)\right) + \theta_0^{w,H2} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right) + \mu \cdot \eta^{-1} - \mu^{H2} = 0 \tag{52}$$

$$\frac{\partial \mathcal{L}}{\partial q_e^{NH2}} = c_e'^{NH2}\left(q_e^{NH2}\right) + \theta_0^{w,H2} \cdot \left(q_e^{CH2,S} + q_e^{CH2,NS} - Q_e^{H2,off} - Q_e^{HPA} + q_e^{NH2}\right) - \mu^{H2} = 0 \tag{53}$$

$$\frac{\partial \mathcal{L}}{\partial d^w} = -\frac{\left(D_0^w - d^w\right)}{\alpha_0^w} + \mu = 0 \tag{54}$$

$$\frac{\partial \mathcal{L}}{\partial d^{w,H2}} = -\frac{\left(D_0^{w,H2} - d^{w,H2}\right)}{\alpha_0^{w,H2}} + \mu^{H2} = 0 \tag{55}$$

As can be seen, the first order optimality conditions of the Cournot equilibrium defined in (45)-(48) and (6) and (18) coincides with the first-order KKT conditions of the optimization problem iff μ and μ^{H2} correspond to prices p and p^{H2}. Moreover, μ and μ^{H2} correspond to prices p and p^{H2} since (8) and (9) evaluated at those prices coincides with (54) and (55) when clearing μ and μ^{H2}. This proves the result.

Corollary I. Equivalency without SMs

The proof is straight forward applying the lemma since:

$$b_e^{H2}\left(q_e^{CH2}, q_e^{NH2}, p, p^{H2}\right) = \hat{b}_e^{H2}\left(q_e^{CH2}, 0, q_e^{NH2}, p, p^{H2}; 0,0\right) \tag{56}$$

Corollary II. Equivalency for the fixed premium SM

The proof is straight forward applying the lemma since:

$$b_e^{H2}\left(q_e^{CH2,S}, q_e^{CH2,NS}, q_e^{NH2}, p, p^{H2}\right) = \hat{b}_e^{H2}\left(q_e^{CH2,S}, q_e^{CH2,NS}, q_e^{NH2}, p, p^{H2}; 0,0\right) \tag{57}$$

Corollary III. Equivalency for the PhOT SM

The proof is straight forward applying the lemma since:

$$b_e^{H2}\left(q_e^{CH2}, q_e^{NH2}, p, p^{H2}\right) = \hat{b}_e^{H2}\left(q_e^{CH2}, 0, q_e^{NH2}, p, p^{H2}; Q_e^{HPA}, 0\right) \tag{58}$$

Corollary IV. Equivalency for the FinOT SM

The proof is straight forward applying the lemma since:

$$b_e^{H2}\left(q_e^{CH2}, q_e^{NH2}, p, p^{H2}\right) = \hat{b}_e^{H2}\left(q_e^{CH2}, 0, q_e^{NH2}, p, p^{H2}; Q_e^{HPA}, 0\right) \tag{59}$$

Appendix B. Input data

Table 4 gathers the main system data used in the case studies while Table 5 collects data of the main electrolyzers in Spain and Portugal.

Table 4. Main system data

Iberian system, 2030	Value	Ref.
Wind capacity [GW]	74.44	[59], [60]
Solar PV capacity [GW]	76.79	[59], [60]
Nuclear capacity [GW]	2.05	[50]
CCGT capacity [GW]	27.44	[50]
Total electrolysis capacity [GW]	15.33	[52] [62], [63], [64]
SMR capacity [ton H_2/d]	2437.4	[50]
Batteries capacity [GW]	8	[59], [60], [69], [70]
Charge and discharge battery efficiency [%]	90	[71]
Hydrogen storage capacity [ton]	17250	[60]
Loss coefficient [%/hour]	0.04	[58]
CO_2 price [€/ton CO_2]	93.05	[50]
TTF NG price [€/MWh]	48.88	[50]

Battery capacities were allocated to agents in proportion to their RE capacities, while hydrogen storage was distributed according to their electrolyzer capacities, as defined in (41). The initial and final SoC of the batteries was set to 50% of their maximum capacity. Regarding hydrogen storage, both the initial and terminal LoH in the tanks were fixed to zero. This assumption avoids accounting for hydrogen that was not physically produced within the year, thereby preventing distortions in the hydrogen dispatch results. For simplicity, hydrogen storage was assumed to operate with ideal charging and discharging efficiencies, i.e.: $\eta^{ch,H2} = \eta^{dis,H2} = 100\%$.

Table 5. Agents' electrolyzers portfolio

Agent	Location	Electrolyzer capacity (MW)	Source of electricity			Dedicated RE capacity (MW)		Technology
			Grid	PPA	DC	Solar (MW)	Wind (MW)	
Agent 1	Spain	850	No	Yes	Yes	1200	18	PEM
Agent 1	Spain	28	No	Yes	No	0	0	PEM
Agent 1	Spain	151	Yes	Yes	No	0	0	PEM
Agent 1	Portugal	137	Yes	No	No	0	0	PEM
Agent 2	Spain	100	No	No	Yes	0	611	PEM
Agent 2	Spain	215	Yes	Yes	No	0	0	PEM
Agent 3	Spain	2280	No	Yes	Yes	950	500	PEM
Agent 3	Spain	30	Yes	Yes	No	0	0	PEM
Agent 4	Spain	1000	No	Yes	Yes	500	500	PEM
Agent 4	Spain	500	Yes	Yes	No	0	0	PEM
Agent 4	Portugal	101	Yes	No	No	0	0	PEM
Agent 4	Portugal	500	Yes	Yes	No	0	0	PEM
Agent 5	Portugal	500	Yes	Yes	No	0	0	PEM
Agent 5	Portugal	1000	Yes	No	No	0	0	PEM
Agent 5	Portugal	8	No	Yes	Yes	15	0	PEM
Agent 5	Spain	415	No	Yes	Yes	144	34	PEM
Agent 5	Spain	120	No	Yes	No	0	0	PEM
Agent 5	Spain	1160	No	No	Yes	1972	1750	PEM
Agent 5	Spain	3703	Yes	Yes	No	0	0	PEM
Agent 5	Spain	650	No	Yes	Yes	1200	0	AEL
Agent 5	Spain	1332	No	Yes	No	0	0	AEL
Agent 5	Spain	550	Yes	No	No	0	0	AEL

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Appendix C. Economic results

The impact of the SMs on incomes, costs and profits is summarized in Table 6, Table 7 and Table 8, respectively. These results should be interpreted with caution, since they depend on simplifying assumptions and other economic elements, such as taxes or depreciation, that have not been included. In the *PhOT* it was assumed that the HPA price equals the yearly average wholesale hydrogen price, and in the *FinOT* the same assumption was considered for the strike price. In the *FP* case, the additional incomes come from the premium multiplied by the amount of subsidized green hydrogen. On the cost side, RE from dedicated facilities is assumed to have negligible operating cost, and hydrogen from PPAs is treated as an exogenous input at $L_e^{PPA,H2}$=40.9 €/MWh, as in [52].

In Table 6, the row "Additional from SM" refers to income obtained outside the wholesale market: i.e.: the premium in *FP*, government-backed contracts in *PhOT*, and the CfD in *FinOT*. Empty cells indicate that there is no additional income from SMs in the corresponding case.

Table 6. Incomes breakdown [M€]

M€	NoSub	RA	FP	PhOT	FinOT	Quota
Total	17271	17267	18072	17343	17291	17246
Electricity sector	5314	5312	5405	5533	5516	5499
Hydrogen sector	11957	11955	12667	11810	11776	11747
Green H_2 (wholesale market)	7642	7711	7751	762	7821	7839
Additional from SM			754	7118	0	
Gray H_2	4315	4245	4162	3930	3955	3908

Table 7. Costs breakdown [M€]

M€	NoSub	RA	FP	PhOT	FinOT	Quota
Total	6509	6651	6859	7545	7420	7421
Electricity sector	545	531	611	731	709	701
Hydrogen sector	5964	6120	6248	6814	6710	6720
Green H_2 from grid	3339	3495	3624	4190	4086	4096
Green H_2 from PPA	307	307	307	307	307	307
Gray H_2	2317	2317	2317	2317	2317	2317

Table 8. Profits breakdown [M€]

M€	NoSub	RA	FP	PhOT	FinOT	Quota
Total	10763	10616	11213	9798	9872	9825
Electricity sector	4769	4780	4795	4802	4807	4798
Hydrogen sector	5993	5836	6419	4996	5065	5027

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