Remuneration Formats in Support Schemes for Hydrogen from Electrolysis: What to Incentivise and Why?

Paolo Mastropietro, Kenneth Bruninx, Rafael Cossent,

Antonio Bello, Pablo Rodilla

This article is a preprint. Please cite the published version:

https://doi.org/10.1016/j.ijhydene.2026.153775

REMUNERATION FORMATS IN SUPPORT SCHEMES FOR HYDROGEN FROM ELECTROLYSIS: WHAT TO INCENTIVISE AND WHY?

Paolo Mastropietro [a, *], Kenneth Bruninx [b], Rafael Cossent [a],
Antonio Bello [a], Pablo Rodilla [a]

[a] Instituto de Investigación Tecnológica, Universidad Pontificia Comillas, Rey Francisco 4, Madrid, Spain.

[b] Faculty of Technology, Policy and Management, TU Delft, Jaffalaan 5, Delft 2628 BX, Netherlands.

[*] Corresponding author. IIT, Universidad Pontificia Comillas, Rey Francisco 4, Madrid, Spain.
Tel.: +34 91 542 2800 ext. 2746. E-mail: <Paolo.Mastropietro@comillas.edu>

Abstract

Support mechanisms for low-carbon hydrogen are becoming increasingly widespread, with large amounts of public funding being invested to underpin the initial development of this new energy sector. A clear distinction has emerged in support schemes for hydrogen production through electrolysis, depending on whether remuneration is expressed per MW of electrolysis capacity or per kg of hydrogen produced. This dichotomy has led many experts to draw parallels with support schemes for renewable electricity generation and their distinction between capacity- and production-based mechanisms. This article contributes to this discussion by: i) providing a theoretical assessment of the similarities and differences between low-carbon hydrogen support schemes and other support mechanisms introduced in the electricity sector; and ii) developing a quantitative assessment based on simulations to explore the impact of selecting a remuneration format for hydrogen support, and to evaluate the economic signals sent to project developers by both remuneration formats.

Keywords

Hydrogen economy; Hydrogen subsidies; Support mechanism; Risk-hedging; Direct grant; Fixed premium; Variable premium.

1 INTRODUCTION AND STATE OF THE ART

Over the past decade, all proposed energy transition pathways have envisioned a pivotal role for low-carbon hydrogen [1][2][3]. In addition to serving as a sustainable feedstock for the chemical industry, low-carbon hydrogen is expected to facilitate the decarbonisation of numerous applications that cannot be electrified and to provide flexibility services to the power sector. However, the true potential of hydrogen as an energy vector is subject to significant uncertainty [4][5]. The discourse surrounding hydrogen has undergone cycles of escalation and decline over the past few decades [6][7], and some authors have already emphasised the discrepancy between current ambitions and the implementation of announced projects [8].

Nevertheless, current ambitions have been backed by a strong political commitment in many jurisdictions, which is materialising into support mechanisms for different elements of the low-carbon hydrogen supply chain [9][10][11]. Support mechanisms for low-carbon hydrogen have been introduced or are under development in the United States, the European Union, Great Britain, Australia, Canada, Japan, South Korea, India, Egypt, Germany, Denmark, the Netherlands, Portugal, Spain, Italy, Sweden and Romania [12]. Most of these support policies focus on hydrogen produced via electrolysis. These schemes are evolving rapidly from small demonstration programmes into large, complex support mechanisms intended to underpin the initial development of large-scale green hydrogen production. However, although academic literature contains numerous technoeconomic analyses of hydrogen projects, the design of support mechanisms for low-carbon hydrogen is strongly underrepresented in this literature. Hoogsteyn et al. [13] develop an equilibrium model to assess the impact that the remuneration format may have on the spot price of electricity. Mastropietro and Rodilla [14] stress the risk that support mechanisms introduces a regulatory segmentation in the low-carbon hydrogen market and argue for centralised hydrogen support mechanisms that bring together producers and end users in the same bidding process. Centralised double-sided auctions are also defended by Vázquez and Hallack [15].

It may be premature at this stage to make definitive recommendations on the design of support mechanisms for low-carbon hydrogen. Many of these schemes are still in the design phase or have only recently completed their first allocation rounds and there is no data to assess the effectiveness of different designs. Furthermore, many uncertainties remain in the hydrogen industry (regarding the scope of this energy vector, the role of certification, and the flexibility of off-taker contracts), which impact the optimal design. Until we can extract lessons learned from real-world policies, it is important to fill this knowledge gap by conducting model-based assessments, which allow us to address specific design elements of hydrogen support schemes that can have a stronger impact on the efficiency of the economic aid.

A clear distinction has emerged in support schemes for hydrogen production through electrolysis. Some governments have opted to offer direct grants covering part of the capital or total expenditure, with the economic aid expressed in terms of MW of electrolysis capacity (or, equivalently, a grant based on a percentage of capital expenditure). Examples include the US Inflation Reduction Act (IRA) 48 [16][1], the British Hydrogen Allocation Rounds (HAR) [18], the Dutch hydrogen auctions [19][20], the Romanian support scheme [21], and the Italian support mechanism for hydrogen valleys [22]. Other regulators have opted for long-term contracts and risk-hedging instruments, typically in the form of a fixed premium (e.g., the European Hydrogen Bank, EHB, auctions [23][24], the Danish Power-to-X scheme [25], the US IRA 45V [16] and the Indian incentive scheme for green hydrogen [26][27]) or a variable premium (e.g., the British Low Carbon Hydrogen Agreements, LCHA [28], and the Australian Hydrogen Headstart [29]) on low-carbon hydrogen sales. In these cases, the economic aid is expressed per kgH_2 (or, equivalently, in per MWh or GJ of hydrogen energy content).

The remuneration format of the support mechanism affects the operation of the electrolyser. When incentives are provided based on production, the willingness to pay for electricity of the electrolyser operator increases, resulting in a shift towards higher values of operating hours and production volumes. When economic aid is awarded through a competitive process, the selection of the remuneration format may alter the equilibrium among different projects. Several governments have considered this effect when designing their support schemes for hydrogen from electrolysis. For example, the Dutch Government [19] stated that ranking bids for economic aid per MW of electrolysis capacity "limits the risk of a single large project taking up the entire budget, as large projects may benefit from economies of scale enabling them to score favourably when ranking based on subsidies per unit of renewable hydrogen produced". The Dutch Government also explained that this award criterion "avoids excessive incentives for projects that will be run for as many full load hours as possible". This is perceived as an advantage, since, at this stage, electrolysers working at

---

[1] Both the IRA 48 and IRA 45V tax credits have undergone modifications with the enactment of the One Big Beautiful Bill Act [17], reducing their scope and expected impact.

full or high load on a continuous basis could increase electricity prices and greenhouse gas emissions from the power system.

Many experts have highlighted the similarities between this discussion and the one developed for support mechanisms for Renewable Energy Sources for Electricity (RES-E) [13][15], especially with regard to distortions in the short-term market. As low-carbon hydrogen support mechanisms, RES-E support schemes can provide incentives either per MW of installed capacity (capacity-based mechanisms) or per MWh of electricity produced (production-based mechanisms). Numerous academic papers and working documents have evaluated the advantages and disadvantages of these two different approaches to incentivising RES-E resources[2]. Huntington et al. [30] present a comprehensive classification of RES-E support schemes based on their design elements. They review the main inefficiencies that production-based mechanisms can generate, such as the incentive to maximise production and the subsequent impact on the occurrence of negative prices in the electricity market. However, they also stress that capacity-based support schemes may maximise renewable installed capacity without maximising clean generation or reducing greenhouse gas emissions. The authors propose a capacity-based support mechanism complemented by ex-post compensation defined for reference benchmark plants, a design inspired by an RES-E support scheme that was implemented in Spain in the past. Barquín et al. [31] also defend capacity-based support schemes, coupling this concept with a menu-of-contracts approach to define a bonus payment that favours installations with a higher market value. Schlecht et al. [32] focus on Contracts-for-Difference (CfDs) and analyses how their design, particularly in terms of contracted volume and settlement period, can distort electricity market prices. As an alternative, they propose implementing a “financial” CfD, which decouples payments from actual generation. Newbery has also proposed a similar contract [33], defending the introduction of a yardstick CfD in which the contracted volume in any hour is equal to the developer’s hourly forecast output per MW capacity, with a life specified in MWh/MW capacity. Kitzing et al. [34] also focus on CfD design, classifying CfD-based schemes as either generation-based or generation-independent CfDs, and highlighting the respective advantages and disadvantages in terms of electricity market

[2] The literature review on the design of RES-E support schemes could be much broader. The goal of this paragraph is only to highlight the most commonly cited drawbacks of production-based RES-E support schemes and the solutions proposed to solve them.

distortions. All these authors advance different proposals towards the same objective, i.e., decoupling support from an asset's production to avoid electricity market distortions.

Similar discussions are being held regarding low-carbon hydrogen support, yet this literature is surprisingly thin. The main reference is Hoogsteyn et al. [13]. These authors develop an equilibrium model and show that mechanisms remunerating hydrogen production can distort spot prices of electricity and hydrogen more strongly than mechanisms that remunerate hydrogen production capacity.

Although support schemes for electricity storage are still less common than RES E support mechanisms, they can also provide valuable insights for providing economic aid to low-carbon hydrogen. As analysed in depth in [35], support for electricity storage can also be provided per MW or per MWh. However, both terms refer to the technical ability of the asset to provide capacity or energy at a given time, the two terms being linked by the storage duration. As per-MWh remuneration does not refer to the energy withdrawn or injected into the grid, the remuneration format, in the case of storage support, is not the most relevant parameter affecting the operation of the assets. The main dichotomy in storage support schemes is between direct grants (a one-off payment covering a portion of the capital expenditure) and financial contracts for risk hedging (yearly payments based on the assets' actual revenues and the gap for revenue adequacy). In the case of risk-hedging contracts, distortions to asset operation and market prices are usually avoided by using efficiently-operated reference plants to calculate the revenue gap to be covered by the support scheme (as in the mechanisms implemented in Greece and Hungary [35]).

This article aims to explore the impact of selecting a remuneration format for hydrogen support and to evaluate the economic signals sent to project developers by both remuneration formats. Section 2 provides a qualitative assessment and discussion of the parallelisms between RES-E and hydrogen support schemes to determine whether recommendations from one context can be applied directly to the other, or whether dissimilarities between the two domains impede this generalisation. Section 3 describes the simulation used in section 4 to compare the most widely used two remuneration formats in hydrogen support schemes (per-MW and per-kgH_2) and their impact on the operation of the electrolyser. Section 5 summarises the main findings of the article and indicates future research lines.

2 PARALLELISMS AND DISSIMILARITIES BETWEEN RES-E AND HYDROGEN SUPPORT

RES-E support schemes, like other support schemes in the electricity sector, have always struggled to strike a balance between multiple objectives. The main goal of these mechanisms has shifted from pure subsidy instruments to the reduction of the perceived risk to market agents (including volume and price risk) and to attract more investment in supported technologies. However, at the same time, the risk hedge should not completely insulate these resources from the market signals that are intended to guide the efficient operation of these assets. As shown in the chart on the left in Figure 1, the optimal support mechanism should encourage renewable resources to try to maximise their production when electricity prices are high and their energy can generate more value for the system (yellow arrow). Conversely, it should prevent these resources from producing when prices are negative (or from submitting offers with negative prices). A similar discussion applied to support mechanisms for electricity storage, which are becoming increasingly common, particularly in the European Union [35]. Once again, the optimal support mechanism (chart on the right in Figure 1) should incentivise these resources to charge during periods of low or negative electricity prices (red arrows), and to discharge when prices are higher (yellow arrows). While these statements may sound obvious, it has proven very complex to achieve these economic signals with support mechanisms that are intended to reduce risk exposure. Proof of this can be seen in the 15 occurrences of 16-hour-long episodes of negative prices in some of the EU-27 bidding zones in 2023, as highlighted by ACER [36]. The brief literature review presented in the introduction listed some proposals to avoid market price distortion arising from support mechanisms.

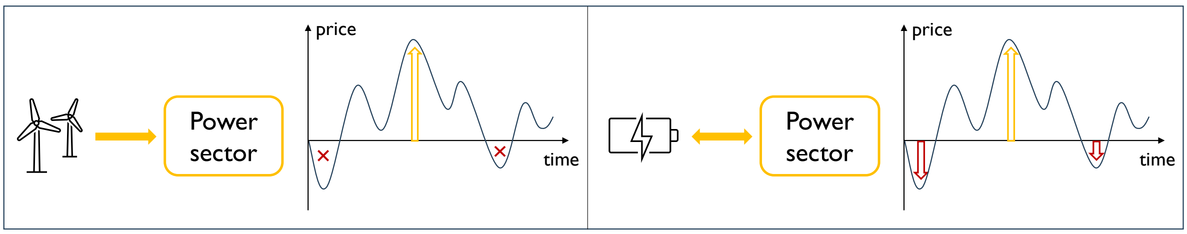

Figure 1. A system-beneficial operation of RES-E (left) and storage (right) resources in the power system; charts represent the evolution of the electricity market price over time.

The conceptual framework for low-carbon hydrogen support schemes is quite different and more complex. Unlike a RES-E resource or a storage asset, which respond to signals from the electricity market alone, an electrolyser interfaces with two different energy systems: it withdraws electricity from the power sector and sells low-carbon hydrogen in the hydrogen market (Figure 2)[3]. Another peculiarity is that the low-carbon hydrogen market, in which the electrolyser would sell its product, is still under development. Currently, there is almost no short-term market, and the long-term market does not yet demonstrate a significant liquidity. In the future, the hydrogen sector may have a market that operates similarly to today's gas market, with lower short-term volatility than the one experienced in the electricity market. For the time being, however, the low-carbon hydrogen market is dominated by support mechanisms and bilateral long-term offtake agreements, which define a long-term price for low-carbon hydrogen projects by combining off-taker prices and economic support (if remuneration is based on hydrogen production).

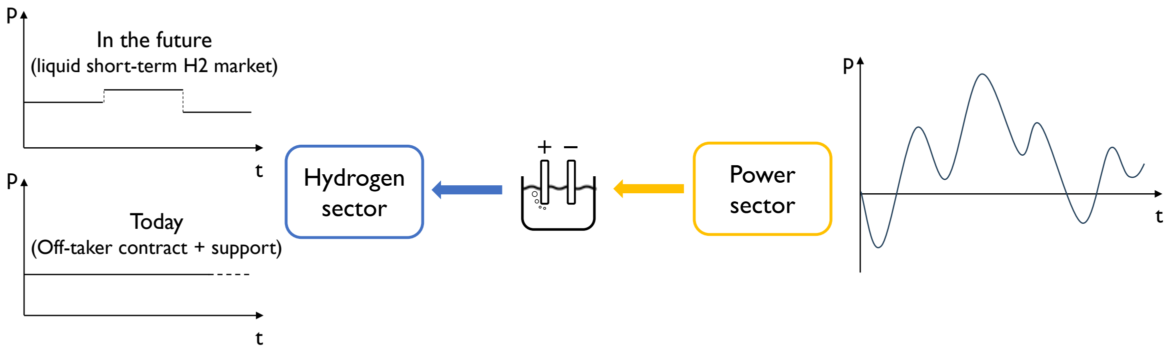

Figure 2. Operation of an electrolyser based on the electricity and hydrogen markets signals.

Exposure to two economic signals from two different domains, the electricity and the hydrogen markets, makes any assessment on the efficient operation of the electrolyser more complex. In the short term, and disregarding any restrictions imposed by off-taker contracts or fixed operational expenditure, the electrolyser should produce hydrogen whenever the revenue from hydrogen sales minus the cost of electricity purchases is greater than zero. This results in the equilibrium of the prices in the two markets presented in Equation 1, where p_{H_2} is the hydrogen market price, p_e is the electricity market price, and β is the electrolyser's average specific consumption. The same formula can also be expressed also as in Equation 2, which highlights the need for the sale price of hydrogen to exceed its marginal production cost.

[3] Electrolysers may also operate stand-alone, with a dedicated renewable power plant. However, since the main objective of this article is to evaluate the impact of different remuneration formats on both the hydrogen and electricity markets, our focus is on grid-connected electrolysers.

$$\frac{p_{H_2}}{\beta} - p_e > 0 \qquad \text{Equation 1}$$

$$p_{H_2} > p_e \cdot \beta \qquad \text{Equation 2}$$

As there is currently no short-term price signal in the hydrogen market, the market price is represented by the off-taker contract price plus any production-based incentives. Figure 3 illustrates the application of Equation 1 to the price charts presented in Figure 2. The left-hand chart in Figure 3 shows the hydrogen market price, which does not vary in the short term, the negative of the electricity market price, and the sum of these two terms. The right-hand chart in Figure 3 shows an efficient operation of the electrolyser, producing hydrogen only when Equation 1 is met (periods with blue arrows, when the curve is higher than zero). Given a hydrogen off-taker contract price, a hydrogen support per kgH_2, and an electricity market price, the only inefficient electrolyser's operation is the one that forces hydrogen production at a cost higher than the price it would be remunerated at in the hydrogen market, including the economic aid.

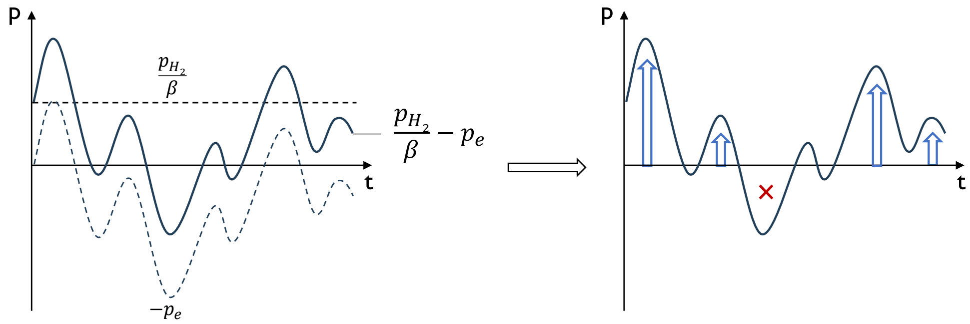

Figure 3. Economic equilibrium in the operation of the electrolyser

This assumption should not be affected by signing a long-term contract that fixes the electricity price, such as a Power Purchase Agreement (PPA) with a renewable power plant. While a PPA does alter the long-term price equilibrium, prompting an investment decision for the electrolyser only if the revenue from hydrogen sales minus the cost of electricity purchased at the PPA price exceeds the capital expenditure (Equation 3, where EED stands for Expected Electricity Demand), it should not impact the short-term equilibrium. In fact, if selling its PPA position in the electricity market brings higher revenues than selling hydrogen at the relevant price (Equation 4), the electrolyser operator should do so, resulting in the same equilibrium defined in Equation 1 and the same efficient operation represented in the right-hand chart in Figure 3.

Long term (investment)	$\left(\frac{p_{H_2}}{\beta} - p_{PPAe}\right) \cdot EED > CAPEX$	Equation 3
Short term (operation)	$\frac{p_{H_2}}{\beta} - p_{PPAe} > p_e - p_{PPAe}$ $\frac{p_{H_2}}{\beta} - p_e > 0$	Equation 4

The off-taker contract price and the hydrogen support mechanism define the price at which the electrolyser would be willing to buy electricity and produce hydrogen, i.e., its utility function in the electricity market. Provided the electrolyser's operation complies with this utility function, it cannot be labelled as inefficient from an economic perspective. A support scheme that provides an incentive per kg of hydrogen produced would shift the curve depicted in Figure 3 upwards and increase operating hours, but it would not result in an operation in the electricity market that could be identified as less economically efficient. Distortions to economic efficiency may arise from other elements of the support scheme or the off-taker contract that are beyond the scope of this article, such as restrictions on the hydrogen production volume within a given settlement period or restrictions imposed by certification schemes[4]. For example, if the electrolyser has to deliver a specific volume of hydrogen during a year of very high electricity prices, it may be forced to produce hydrogen at a cost higher than its market value[5], thus violating its utility function in the electricity market.

This analysis also reminds us that, as they sit at the intersection of two different energy sectors, electrolysers are subject to double price risk (with the volume risks being correlated). While the hydrogen support scheme may provide a hedge against hydrogen price risk (e.g., through a variable premium over the hydrogen price or a hydrogen CfD), it

---

[4] Restrictions on the hydrogen volume are common in low-carbon hydrogen support schemes [24][28]. Enrolment in the support scheme may be also require certification, such as that for Renewable Fuels of Non-Biological Origin (RFNBOs) [37] or for low-carbon hydrogen and fuels [38]. In this article, we do not argue against these elements of the low-carbon hydrogen support scheme, which may be necessary at this stage in the development of the low-carbon hydrogen sector. We only mention here their potential impact on an economic-efficient operation of the electrolyser responding only to price signals.

[5] This is especially true in this initial stage, when the price in the hydrogen market is not strongly correlated with the electricity market price. Hydrogen market value is currently driven by off-taker contracts and the off-takers' willingness to pay is more related to price of hydrogen from steam methane reforming.

generally has no impact on the electricity price risk. The only support scheme that could protect the electrolyser from both price risks would be one with a variable premium that always covers any difference between the electricity purchase price and the hydrogen sale price, in all relevant settlement periods[6]. A support scheme based on this incentive could also require a hydrogen off-taker contract and an electricity PPA, as well as introducing strict volume requirements, closing all commercial positions. However, the economic efficiency of such a support scheme would be questionable, since it would insulate the electrolyser completely from the economic signals conveyed by the hydrogen and electricity markets. If the power system undergoes a period of stress that results in sustained prices (such as that experienced in Europe in 2022), the electrolyser operating under this hypothetical support scheme would maintain its electricity demand unaltered. While this operation may be feasible in the early stages of low-carbon hydrogen development, it is not suitable for the large-scale deployment of hydrogen as an energy vector.

In summary, although there are some parallelisms between the RES-E and hydrogen support schemes and the operational incentives they send to supported resources, these similarities are limited by the greater economic complexity of operating an electrolyser, which sits at the intersection of the electricity and hydrogen sectors, and by the current underdevelopment of the low-carbon hydrogen short- and long-term markets. Regardless of whether remuneration is provided per MW of electrolysis capacity or per kg of hydrogen produced, most of distortions introduced by the hydrogen support scheme affect the hydrogen sector, potentially prompting the electrolyser to produce hydrogen at a cost higher than its market value. However, this risk is currently difficult to assess, since there is no liquid short-term market for low-carbon hydrogen. Conversely, if the electrolyser operates in the electricity market in accordance with its utility function, as defined by the off-taker contract and the support mechanism, this operation cannot be considered economically inefficient.

In summary, one of the main distinctions in support schemes for low-carbon hydrogen from electrolysis concerns the remuneration format, either per MW or per kgH_2. As the similarities between RES-E and low-carbon hydrogen support schemes are limited by the nature of the electrolyser business model and the current status of the hydrogen market.

---

[6] Similar incentives have been introduced in the British Low Carbon Hydrogen Agreements, LCHA [28], and the Australian Hydrogen Headstart [29]. However, the low frequency of recalculations of the variable premium limits the inefficiencies mentioned in this paragraph.

Therefore, it is not possible to directly translate the lessons learned from the electricity sector (capacity-based vs. production-based support) to the nascent low-carbon hydrogen sector. The remainder of the article presents a quantitative assessment of the impact that selecting a remuneration format may have on electrolyser operation and economic equilibrium between different projects in auctions for economic aid.

3 MATERIALS AND METHODS

The quantitative analysis is based on a simulation of the economic performance of an electrolyser that purchases electricity from the market and sells hydrogen to an off-taker at a set price. This exercise enables calculating the economic gap required for the project to be viable, as well as the economic aid that the electrolyser would need from the support scheme, expressed on a per-MW and a per-kgH_2 basis. The economic aid is also assessed through a sensitivity analysis of parameters affecting the electrolyser's economic performance (installed capacity, average specific consumption and hydrogen sale price). The impact of errors in the prediction of electricity prices and the signing of a PPA in the electricity market is also evaluated by repeating the simulations with different assumptions.

Table i presents the main technoeconomic variables of the electrolyser used in the simulation. These data were interpolated from those used for the reference projects in the national assessments submitted to the European Commission for approval of the support scheme [19][20][25]. The hydrogen selling price in Table i represents the willingness to pay by a potential off-taker. This price does not allow for cost recovery, meaning the electrolyser requires economic support to bridge the financial viability gap.

Table i. Technoeconomic variables of the electrolyser

Electrolyser installed capacity	50	MW
Investment costs	2523	€/kW
Fixed operation costs	100	€/kWe·year
Average specific consumption	58	kWh/kgH_2
Hydrogen selling price	3	€/kgH_2
Weighted average cost of capital	8	%

To simulate the operation of the electrolyser in the electricity market, we use a 10-year price time series corresponding to the day-ahead electricity market price in the Spanish bidding zone between 2015 to 2024 (Figure 4). During this period, the Spanish electricity market experienced normal operating conditions and pricing, as well as stress events that caused short-term price spikes (e.g., in January 2021 due to an extreme weather event) and long-term sustained price increases (e.g., the price crisis since 2022). This variability enables us to assess the economic performance of the electrolyser in changing conditions. The price time series is used as an exogenous variable, i.e., it does not vary in response to the operation of the electrolyser.

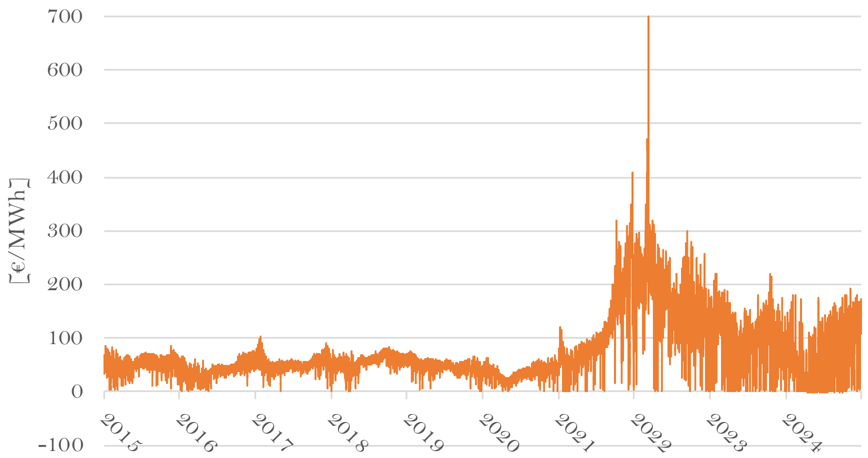

Figure 4. Electricity price curve used in the simulation, corresponding to the Spanish day-ahead market price; data from Red Eléctrica de España [39]

The algorithm behind the simulation decides, for each hour within the 10-year time horizon, whether the electrolyser will produce hydrogen at full load, depending on the hydrogen sale price (plus any per-kgH_2 support) and the average specific consumption, as per Equation 1. If the support is provided per MW of electrolysis capacity, the algorithm calculates the net present value of the cash flow and determines the initial grant required to bring it to zero. If the support is provided per kg of hydrogen produced, the subsidy affects the operation of the electrolyser (see Equation 1) and the algorithm must determine the unitary subsidy required to bring the net present value of the cash flow to zero. The simulation is run over the 10-year time horizon, which also represents the electrolyser's useful life and the duration of the support scheme[7], if paid on a per-kgH_2 basis.

[7] While 10 years is a reasonable duration for a hydrogen subsidy (it is the time horizon during which the EHB premium is paid [23][24]), electrolysers' useful life can reach 20-25 years. For the purposes of this article, we have set the useful life at 10 years to have a consistent timeframe for the main variables under study. Depending on forecasts of the evolution of the hydrogen price, setting a larger useful life can increase or decrease the required economic aid, but the effect is the same for both remuneration formats.

It should be noted that the aim of this case study is not to simulate the real-life operation of an electrolyser or to provide an accurate technoeconomic analysis on low-carbon hydrogen production. Rather, it is intended to evaluate the impact of altering the remuneration format of the hydrogen support scheme, and we apply many simplifications that help us focusing on this objective. Therefore, results presented in Section 4 should be read in support to the theoretical discussion presented in Section 2. In addition, as mentioned in Section 2, we have intentionally not modelled any restrictions arising from the off-taker contract or the certification scheme. Similarly, we have not modelled electricity or hydrogen storage. Adding these layers of complexity would make the results more difficult to interpret, and the aim of this article is to examine the basic impact of selecting a certain remuneration format. Furthermore, this research is intended to provide recommendations for designing a low-carbon hydrogen support scheme. These are long-term mechanisms, and it is unclear whether these restrictions would still be in place in the long term[8].

4 RESULTS AND DISCUSSION

4.1 Base Case

Before presenting the base case results, it is important to highlight the relationship between economic aid and the equivalent full load hours of electrolyser operation. Figure 5 illustrates how full-load hours fluctuate based on the level of economic aid for the electrolyser and the electricity market prices outlined in section 3. When economic aid is provided per MW of electrolyser capacity, operating hours are independent of the economic aid and remain constant at a value determined by the electricity market price and the hydrogen sale price (off-taker contract). Conversely, when economic aid is provided per kg of hydrogen produced, an increase in aid results in higher operating hours, in accordance with the equilibrium defined by Equation 1. In this case study, this effect saturates at economic aid

[8] At this early stage in the development of the low-carbon hydrogen supply chain, many of the off-take contracts stipulate strict production volume requirements, which could result in inflexible electrolyser operation. This is due to the current lack of infrastructure, with electrolysers being developed to supply the decarbonisation of a specific industrial facility, which usually does not have access to alternative sources of low-carbon hydrogen. If the hydrogen economy grows and low-carbon hydrogen becomes a real energy vector, it is likely that many of these restrictions and physical contracts will disappear, as has happened in other energy sectors (electricity and gas).

values larger than 15 €/kgH_2, after which the electrolyser operates at full capacity throughout the year.

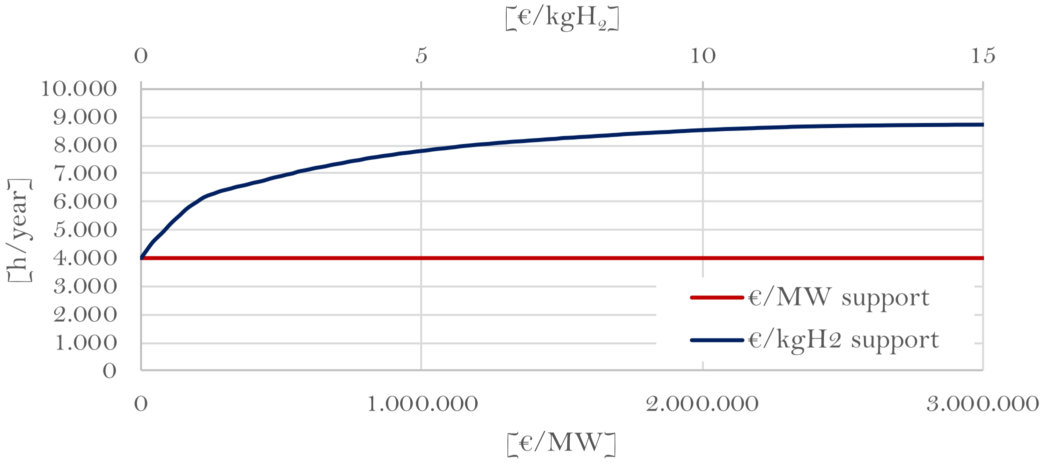

Figure 5. Relationship between the economic aid (on a per-MW and a per-kgH_2 basis) and the equivalent full load hours; average over the 10-year time horizon

Bearing in mind this relationship, we can now analyse the simulation results for the base case, presented in Table ii. If the economic gap of the electrolyser over the 10-year time horizon were expressed per MW of electrolyser capacity, the electrolyser would operate at full load for an average of 4 017 hours per year, produce 34,63 kton of hydrogen per year and require economic aid of 2,75 M€ per MW. If economic aid were provided per kg of hydrogen produced, the electrolyser would optimise its production to require the lowest possible subsidy. It would operate for an average of 7 356 full load hours, almost doubling its hydrogen production to 63,41 ktonH_2, requiring an economic aid of 3,54 €/kgH_2. As mentioned in section 3, these values represent the economic aid that brings the net present value of the project to zero.

Table ii. Economic aid required in the base case depending on the remuneration format

	€/MW support	**€/kgH_2 support**
Average full-load hours [h]	4 017	7 356
Total electricity demand [GWh]	2 009	3 678
Total hydrogen production [ktonH_2]	34,63	63,41
Discounted total electricity costs [M€]	51,78	129,29
Discounted total hydrogen revenues [M€]	74,05	288,99
Economic aid [€/MW]	2 748 588	-
Economic aid [€/kgH_2]	-	3,54
Discounted aid intensity [€/kgH_2]	3,97	2,47

The simulation also enables the calculation of the discounted aid intensity by dividing the discounted economic aid by the total hydrogen production. As shown in Table ii, the per-kgH_2 remuneration format requires a larger economic aid, but it prompts the electrolyser to produce larger volumes of hydrogen, and the aid intensity is lower if compared with an economic aid provided on a per-MW basis.

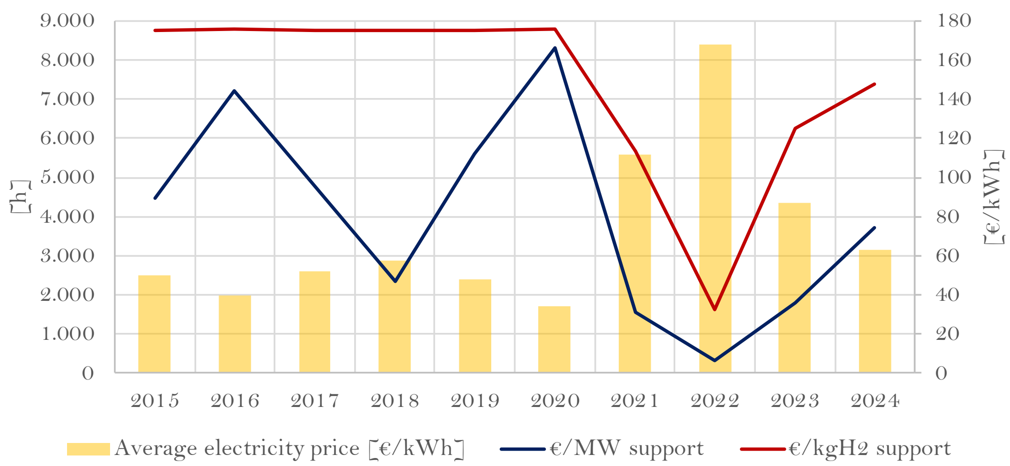

Figure 6. Relationship between the average electricity price (yellow columns and right axis) and the equivalent full load hours for per-MW (blue line) and per-kgH_2 (red line) remuneration formats

Figure 6 shows the yearly disaggregation of the relationship between full load hours and the average electricity price for both remuneration formats. As expected, full load hours are higher in years with lower electricity prices. In 2022, with an average electricity price of 168 €/MWh, operating hours were at their lowest: 327 hours for remuneration per MW and 1 641 hours for remuneration per kgH_2. However, operating hours are significantly higher when the subsidy is provided per kg of hydrogen produced, with the electrolyser running at full capacity throughout 2017-2019.

4.2 Sensitivity analyses

Sensitivity analyses have been conducted on the base case to evaluate how the economic aid, expressed on a per-MW and per-kgH_2 basis, fluctuates with specific technoeconomic variables of the electrolyser and which projects may benefit from one remuneration format over another. Figure 7 shows the results of a sensitivity analysis of the electrolyser's installed capacity. Economic aid is recalculated for installed capacities from 5 to 150 MW. Economies of scale are accounted for using a polynomial function[9] from [40].

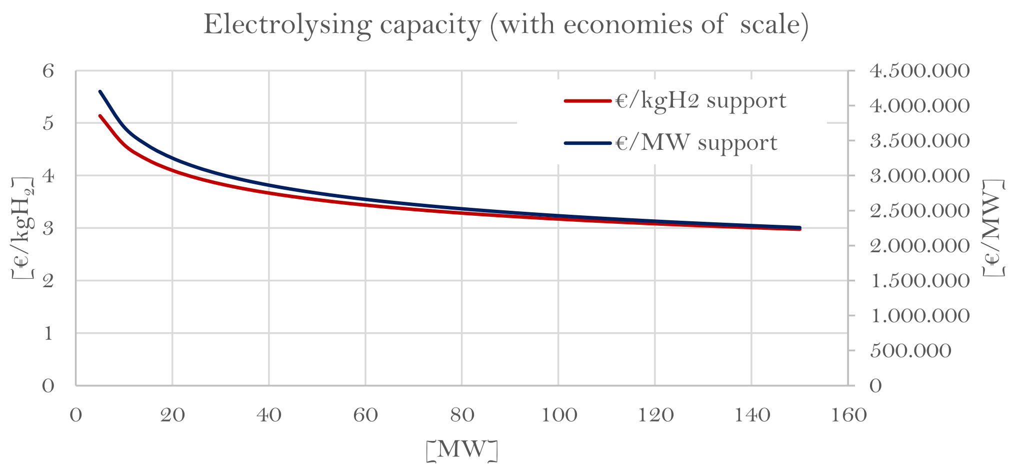

Figure 7. Sensitivity analysis of the electrolyser capacity, taking into account economies of scale

The results invalidate the hypothesis that ranking bids for economic aid by MW of electrolysis capacity limits the advantage of larger projects that benefit from economies of scale. Projects with larger installed capacity are indeed favoured, since they can bid for lower economic aid than smaller projects. However, the effect is very similar for the two remuneration formats, which both show the same decreasing trend.

[9] The formula proposed in [40] uses a CAPEX scaling factor equal to $x^{-0,1976}$, where x stands for the electrical rated power of the electrolyser.

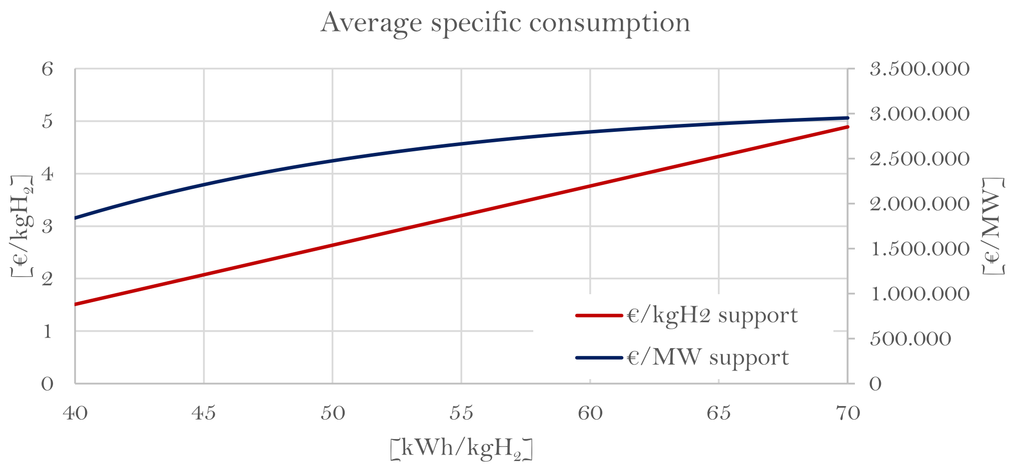

Figure 8. Sensitivity analysis of the average specific consumption

Figure 8 shows the results of a sensitivity analysis of the average specific consumption. With both remuneration formats, a project with lower average specific consumption (i.e., higher conversion efficiency) requires less economic aid. However, the two curves do not have the same shape. Within the typical electrolyser specific consumption range (50 to 60 kWh/kgH_2), a per-kgH_2 remuneration format gives a greater advantage to projects with lower average specific consumption.

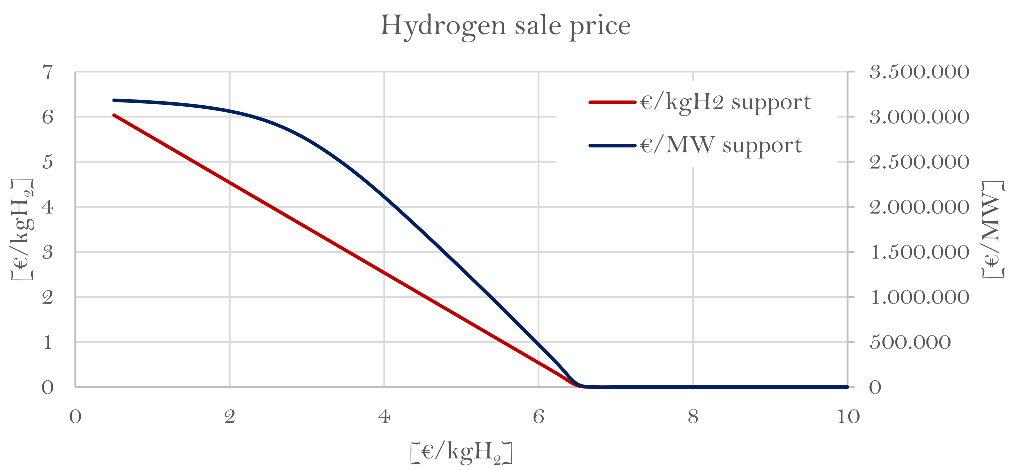

Figure 9. Sensitivity analysis of the hydrogen sale price

Figure 9 shows the results of a sensitivity analysis of the hydrogen sale price. With both remuneration formats, projects that sign off-taker contracts at higher hydrogen prices obviously require less economic aid. For hydrogen sale prices higher than 6,5 €/kgH_2, no support is required. As in the previous case, the curves have different shapes. While the per-kgH_2 economic aid decreases linearly with hydrogen sale price, the per-MW economic aid internalises the change in the operating hours differently, presenting a softer decrease for hydrogen sale prices lower than 3 €/kgH_2 and a harder decrease afterwards.

4.3 Exposure to errors in price projections

The simulation based on a 10-year electricity price curve also allows us to how the remuneration format affects the electrolyser's exposure to errors in electricity price projections. If the electrolyser calculates the required economic aid based on this curve, the incentives per MW or per kgH_2 would be as shown in Table i for the base case. By fixing these incentives and simulating the operation of the electrolyser with different price curves, we can evaluate its exposure to forecast errors by calculating the net present value of all its cash flows. For this case study, we consider electricity price curves showing a 50% decrease or increase compared to the original prices. The results are shown in Table iii.

Table iii. Electrolyser exposure to errors in the forecast of electricity prices

	Real electricity prices = 100% forecast		Real electricity prices = 150% forecast		Real electricity prices = 50% forecast	
	€/MW support	€/kgH_2 support	€/MW support	€/kgH_2 support	€/MW support	€/kgH_2 support
Economic aid [M€/MW]	2,75	-	2,75	-	2,75	-
Economic aid [M€/kgH2]	-	3,54	-	3,54	-	3,54
Average full-load hours [h]	4 017	7 356	1 467	6 345	7 150	8 543
Net present value [M€]	**0**	**0**	**-12,36**	**-57,67**	**+45,81**	**+75,45**

If the actual electricity prices are equal to the forecast used to calculate the economic aid, the operating hours will be as shown in Table ii for the base case, and the net present value of the project will be zero for both remuneration formats.

If electricity prices are 50% higher than those used in the forecast to calculate the economic aid, the electrolyser is forced to reduce its operating hours. However, with a per-MW incentive, the electrolyser receives the economic support regardless of its actual production and can reduce its operating hours in response to the real prices. Conversely, with a per-kgH_2 incentive, the electrolyser receives support for its hydrogen production and must maintain operating hours at a higher level to receive the subsidy. The net present value is negative for both remuneration formats, but the economic loss is greater for the per-kgH_2 support.

If electricity prices are 50% lower than those used in the forecast to calculate the economic aid, the electrolyser increases its operating hours to take advantage of the lower prices. The net present value is positive with both remuneration formats, but the economic profit is larger with the per-kgH_2 support, as this allows the electrolyser to adjust its production volume to achieve higher revenues.

Analysing the range in which the project's net present value varies for a ±50% change in electricity prices reveals that the range is much larger for per-kgH_2 support (133 M€) than for per-MW support (58 M€). This may sound counterintuitive, given that a per-kgH_2 incentive, such as a fixed or variable premium on hydrogen production, is intended to better mitigate the risk for electrolysers. However, as mentioned in section 2, this risk-hedging tool protects the electrolyser from the hydrogen price risk but does not hedge against electricity price or volume risk. This simple case study shows that the electricity price risk is similar for both remuneration formats, but a per-kgH_2 incentive increases the electrolyser's exposure to the volume risk, since the economic aid it receives is proportional to the volume of hydrogen produced. This remuneration format may require ex-post compensation based on the operation of a reference electrolyser, as proposed for RES-E support schemes (section 1).

4.4 The impact of electricity PPAs

The numerical case study can also be used to evaluate the impact of a PPA contract on the operation of the electrolyser and the required economic aid, as well as to verify some of the hypotheses presented in section 2. The base case simulation is repeated assuming that the electrolyser has signed a PPA[10] for the provision of electricity at a price of 50 €/MWh (the average electricity price over the simulation's 10-year horizon is 71 ,06 €/MWh). In this case, in addition to deciding whether to produce hydrogen or not, the electrolyser must also decide whether to retain or sell its PPA position in the electricity market. The results are shown in Table iv.

[10] Just as restrictions on volume production were not modelled for hydrogen, volume restrictions have not been considered for the PPA either. The PPA is modelled as a purely financial contract at a certain price.

Table iv. Economic aid required with a 50-€/MWh PPA depending on the remuneration format

	€/MW support	**€/kgH₂ support**
Average full-load hours [h]	4 017	6 877
Total electricity demand [GWh]	2 009	3 438
Total hydrogen production [ktonH$_2$]	34,63	59,28
Discounted total electricity costs [M€]	71,58	122,00
Discounted total hydrogen revenues [M€]	74,05	227,67
Discounted total PPA sale revenues [M€]	68,46	54,04
Economic aid [€/MW]	1 775 429	-
Economic aid [€/kgH$_2$]	-	2,41
Discounted aid intensity [€/kgH$_2$]	2,56	1,71

With both remuneration formats, the PPA reduces the required economic aid, which decreases from 2,75 M€/MW to 1,77 M€/MW and from 3,54 €/kgH$_2$ to 2,41 €/kgH$_2$. This is simply because, in this case study, the PPA is signed at a price significantly below the electricity market price over the time horizon considered in the simulation. As we are not modelling hydrogen volume restrictions, the electrolyser can decide to sell its PPA position when the electricity price is high. In the simulation, the electrolyser generates substantial revenue from selling the PPA with both remuneration formats.

With a per-MW incentive, the electrolyser operates exactly in the same way as in the base case, with an average of 4 017 full-load operating hours. This confirms that a long-term financial contract that fixes the electricity price, as shown in Equation 4, does not alter the operation of the electrolyser. Conversely, with a per-kgH$_2$ incentive, the electrolyser's operation is affected by the PPA. With this remuneration format, the electrolyser optimises its production to require the lowest possible subsidy and the PPA alters this optimisation. Since the required incentive is lower, the operating hours decrease from 7 356 to 6 877.

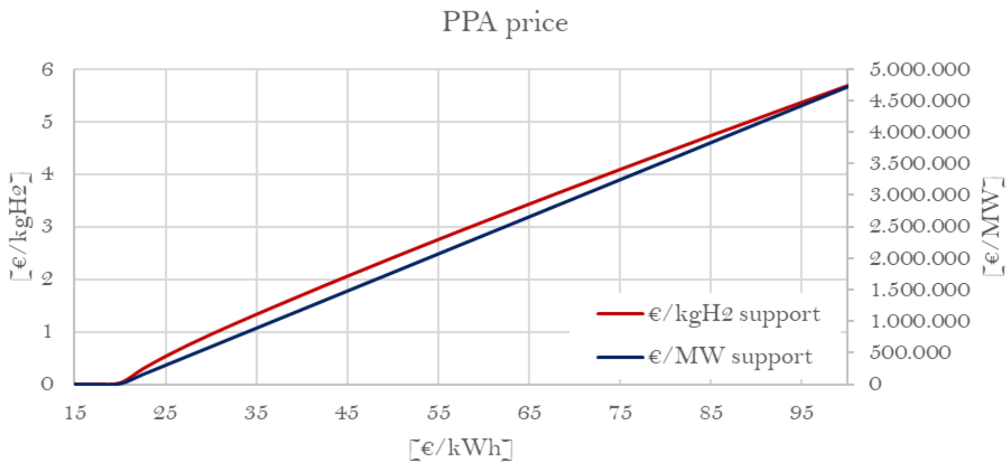

Figure 10. Sensitivity analysis of the PPA price

Figure 10 shows the results of a sensitivity analysis of the PPA price. As expected, lower PPA prices for electricity provision result in less economic support being required. For PPA prices below 20 €/MWh, the electrolyser requires no economic support. For higher PPA prices, the per-MW economic aid increases linearly, while the per-kgH_2 economic aid increases according to a different function. However, the effect is very similar.

5 CONCLUSIONS AND FUTURE WORK

Many jurisdictions around the world have introduced support mechanisms for low-carbon hydrogen, and billions of euros of public funding will soon flow into the nascent hydrogen sector. Most of these schemes target hydrogen produced by electrolysis and can be divided into incentives for electrolysis capacity (€/MW support) and subsidies for hydrogen production (€/kgH_2 support). This dichotomy resembles that which characterised the deployment of support mechanisms for Renewable Energy Sources for Electricity (RES-E), the subdivision of which into capacity-based and production-based support has been widely analysed in the academic literature.

However, the greater complexity of an electrolyser's business model limits the possibility of applying the lessons learned from RES-E support mechanisms to the hydrogen sector. Unlike a RES-E project, an electrolyser has positive variable costs, and its operating expenses typically dominate its cost structure. As it sits at the intersection of the electricity and the hydrogen markets, an electrolyser is exposed to the price risks of both. A hydrogen subsidy expressed per kg of hydrogen produced can reduce the exposure to the risk arising from the hydrogen market, but not the exposure to the electricity price risk. Such a subsidy could generate distortions in the hydrogen market, causing the electrolyser to produce hydrogen at a cost higher than its intrinsic market value. Nevertheless, the low-carbon hydrogen market does not rely on a liquid short-term market capable of producing an economic signal reflecting the actual market value of this energy vector. Currently, the market price of low-carbon hydrogen is being defined by long-term off-taker contracts and hydrogen support schemes. Provided the electrolyser operates within the electricity market according to the utility function created by the prices in these contracts, it cannot be considered inefficient from an economic standpoint.

This article presents a quantitative assessment of the impact that choosing a remuneration format can have on electrolyser operation and economic equilibrium across different projects. As expected, the outcome of the numerical case studies demonstrates that the choice of the remuneration format does affect electrolyser operation,. With a per-MW incentive, electrolyser operation is entirely dependent on the balance between the electricity purchase price and the hydrogen sale price (as well as the specific consumption). With a per-kgH_2 incentive, however, the electrolyser must optimise its operation and hydrogen production to require the lowest possible subsidy, which results in an increase in equivalent full-load operating hours. However, our case studies also demonstrate that the per-kgH_2 remuneration format requires a lower discounted aid intensity than economic aid provided on a per-MW basis.

The sensitivity analyses show that the economic aid required by a project, both per-MW and per-kgH_2, exhibit very similar trends in response to variations in the installed electrolyser capacity, average specific consumption, hydrogen sale price, and the price of the Power Purchase Agreement (PPA) for the electricity consumption. Signing a PPA does not affect the operation of the electrolyser if the aid is provided per MW. However, with a per-kgH_2 incentive, the PPA and the revenues it may generate when electricity prices are high do affect the subsidy required for the electrolyser to be viable, and therefore its operation. The case studies also analysed how the two remuneration formats affect the electrolyser's exposure to errors in electricity price projections. An electrolyser with a per-kgH_2 incentive is more exposed to this risk, demonstrating that, while a risk-hedging contract on hydrogen production protects the electrolyser from the hydrogen price risk, it does not hedge against electricity price or volume risk.

This assessment does not provide any clear indication of the most suitable remuneration format for low-carbon hydrogen support schemes. The answer probably depends on the rationale behind introducing the scheme. Support mechanisms in energy markets typically address specific externalities, i.e., costs or benefits that are not reflected in the market price of a product or service, or market failures (e.g., missing markets for risk hedging). In the case of low-carbon hydrogen, these schemes may target innovation externalities by accelerating the development of the supported technology, thereby reducing its cost and promoting its adoption. They may also target environmental externalities by favouring the supported technology over competitive technologies due to its lower emissions. When assessing RES-E support mechanisms, Özdemir et al. [41] argued that capacity-based support results in greater investment and is more effective at reducing technology costs. In contrast, production-based support is more cost-effective when the objective is to achieve targets for renewable energy penetration or emission reduction. The discussion on low-carbon hydrogen may be similar at this stage. If the objective of hydrogen support schemes is to reduce the cost of producing hydrogen through electrolysis, incentives per MW may introduce fewer distortions in both the electricity and hydrogen sectors. However, if the goal is to foster the production of low-carbon hydrogen to replace hydrogen of fossil origin and reduce final emissions, incentives per kgH_2 may be the most efficient option. As different externalities must be addressed at this stage in the development of the hydrogen economy, it is also possible to combine the two remuneration formats, as is done in the British HAR [18], where projects compete for a risk-hedging contract, but selected projects also receive a 20% CAPEX grant.

The analysis presented in this article has several limitations. The simulation model used in this article was intentionally kept as simple as possible to focus on the effects under study, without accounting for many technical or regulatory elements whose impact could not be isolated in the results. However, future research should urgently explore the impact of other elements of the off-taker contract or the hydrogen support mechanism, such as restrictions on the production volume within a given settlement period or those imposed by certification schemes. While these commercial and regulatory requirements (and the potential distortions they introduce) may be justified during the initial phase of hydrogen industry development, they may not be suitable for the large-scale deployment of electrolysers. Future research should also repeat the analyses presented here using an enhanced model of the electrolyser that more accurately reflects its technical characteristics and that includes other elements such as electricity and hydrogen storage. Another area of research worth exploring is how different remuneration formats can be efficiently combined within the same hydrogen support scheme. From a theoretical point of view, it would also be interesting to analyse support schemes for cogeneration and extrapolate recommendations for the hydrogen sector. Like electrolysers, cogeneration assets operate at the intersection of two energy markets, so there may be more similarities between the two business models, allowing for a more direct application of the lessons learned.

ACKNOWLEDGMENTS

The research presented in this article was partially developed in the framework of the ONESYSTEM research project (grant CPP2022-009711), funded by MICIU/AEI /10.13039/501100011033 and by the European Union NextGenerationEU/PRTR. Paolo Mastropietro, Antonio Bello, and Pablo Rodilla would like to thank the Spanish Ministry of Science and Innovation and the Spanish State Research Agency.

REFERENCES

[1] IEA, International Energy Agency, 2021. Net Zero by 2050: A Roadmap for the Global Energy Sector. Revised version, October 2021. Report.

[2] IRENA, International Renewable Energy Agency, 2023. World Energy Transitions Outlook 2023: 1.5°C Pathway. ISBN: 978-92-9260-527-8. Report.

[3] United States Department of State and the United States Executive Office of the President, 2021. The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050. Working document.

[4] European Hydrogen Backbone, 2021. Analysing Future Demand, Supply, and Transport of Hydrogen. Report.

[5] Liebreich, M., 2022. The Unbearable Lightness of Hydrogen. BloombergNEF article.

[6] Sperling, D., Cannon, J. S., 2004. Hydrogen Hope or Hype. In: The Hydrogen Energy Transition, Academic Press, ISBN: 978-0-12-656881-3, pp. 235-239.

[7] Yap, J., McLellan, B., 2024. Exploring Transitions to a Hydrogen Economy: Quantitative Insights from an Expert Survey. International Journal of Hydrogen Energy, vol. 66, pp. 371-386.

[8] Odenweller, A., Ueckerdt, F., 2025. The Green Hydrogen Ambition and Implementation Gap. Nature Energy, vol. 10, pp. 110-123.

[9] IEA, International Energy Agency, 2023. Global Hydrogen Review 2025. Report.

[10] Pleshivtseva, Y., Derevyanov, M., Pimenov, A., Rapoport, A., 2023. Comparative Analysis of Global Trends in Low Carbon Hydrogen Production Towards the

Decarbonization Pathway. International Journal of Hydrogen Energy, vol. 48, iss. 83, pp. 32191-32240.

[11] Pleshivtseva, Y., Derevyanov, M., Pimenov, A., Rapoport, A., 2023. Comprehensive Review of Low Carbon Hydrogen Projects Towards the Decarbonization Pathway. International Journal of Hydrogen Energy, vol. 48, iss. 10, pp. 3703-3724.

[12] Mastropietro, P., Rodilla, P., 2025. A taxonomy of Support Mechanisms for the Low-carbon Hydrogen Supply Chain. International Journal of Hydrogen Energy, vol. 105, pp. 169-178. DOI 10.1016/j.ijhydene.2025.01.275.

[13] Hoogsteyn, A., Meus, J., Bruninx, K., Delarue, E., 2025. Interactions and Distortions of Different Support Policies for Green Hydrogen. Energy Economics, vol. 141, art. 108042.

[14] Mastropietro, P., Rodilla, P., 2025. Support Mechanisms for Low-Carbon Hydrogen: The Risks of Segmenting a Commodity Market. Energy Policy, vol. 202, art. 114605. DOI 10.1016/j.enpol.2025.114605.

[15] Vazquez, M., Hallack, M., 2024. Auctions to Reveal Consumers' Willingness to Pay for Low-Carbon Hydrogen Projects: Combining Lessons from Renewables and Natural-Gas Industries. Clean Energy, vol. 8, iss. 4, pp. 103-110.

[16] ICCT, International Council on Clean Transportation, 2024. Understanding the proposed guidance for the Inflation Reduction Act's Section 45V Clean Hydrogen Production Tax Credit. Report.

[17] United States Committee on Ways and Means, 2025. The One, Big, Beautiful Bill. Working document.

[18] DESNZ, Department for Energy Security & Net Zero, 2023. Price-based competitive allocation for low carbon hydrogen production - Call for evidence on the future policy framework for allocation of the Low Carbon Hydrogen Production Business Model. Working document.

[19] European Commission, 2023. State Aid SA.101998 (2023/N) – the Netherlands. Hydrogen production through electrolysis. Working document. Page 19.

[20] European Commission, 2024. State Aid SA.110068 (2024/N) – the Netherlands Hydrogen production through electrolysis 2024. Working document.

[21] European Commission, 2022. State Aid SA.102003 (2022/N) – RRF Romania. Scheme to support capacity for renewable hydrogen production. Working document.

[22] European Commission, 2023. State Aid SA.106007 (2023/N) – Italy. TCTF: RRF - Italy: Support for the development of hydrogen valleys. Working document.

[23] European Commission, 2025. Nearly €1 billion awarded to boost development of renewable hydrogen. Press release.

[24] European Commission, 2024. European Hydrogen Bank auction provides €720 million for renewable hydrogen production in Europe. Press release.

[25] European Commission, 2023. State Aid SA.103648 (2022/N) – Denmark. State aid measure to support the industrialization and upscaling of the production of PtX. Working document.

[26] Government of India, Ministry of New and Renewable Energy, 2023. Scheme Guidelines for Implementation of "Strategic Interventions for Green Hydrogen Transition (SIGHT) Programme - Component II: Incentive Scheme for Green Hydrogen Production (under Mode 1)" of the National Green Hydrogen Mission. Working document.

[27] Government of India, Ministry of New and Renewable Energy, 2023. Scheme Guidelines for Implementation of "Strategic Interventions for Green Hydrogen Transition (SIGHT) Programme - Component II: Incentive for Procurement of Green Ammonia Production (under Mode 2A)" of the National Green Hydrogen Mission. Working document.

[28] Government of the United Kingdom, 2022. Agreement for the Low Carbon Hydrogen Production Business Model - Heads of Terms. Working document.

[29] ARENA, Australian Renewable Energy Agency, 2023. Hydrogen Headstart Guidelines. Working document.

[30] Huntington, S.C., Rodilla, P., Herrero, I., Batlle, C., 2017. Revisiting Support Policies for RES-E Adulthood: Towards Market Compatible Schemes. Energy Policy, vol. 104, pp. 474-483.

[31] Barquín, J., Rodilla, P., Cossent, R., Batlle, C., 2017. Obtaining Best Value for Money in RES Auctions: a Capacity-Based with an Embedded Menu of Contracts Approach. Working paper IIT-17-177A.

[32] Schlecht, I., Maurer, C., Hirth, L., 2024. Financial Contracts for Differences: The Problems with Conventional CfDs in Electricity Markets and How Forward Contracts Can Help Solve Them. Energy Policy, vol. 186, art. 113981.

[33] Newbery, D., 2023. Efficient Renewable Electricity Support: Designing an Incentive-compatible Support Scheme. The Energy Journal, vol. 44, no. 3.

[34] Kitzing, L., Held, A., Gephart, M., Wagner, F., Anatolitis, V., Klessmann, C., 2024. Contracts-for-Difference to Support Renewable Energy Technologies:

Considerations for Design and Implementation. FSR Research Project Report 2024/03.

[35] Mastropietro, P., Rodilla, P., Batlle, C., 2024. A Taxonomy to Guide the Next Generation of Support Mechanisms for Electricity Storage. Joule, vol. 8, pp. 1196-1204. DOI 10.1016/j.joule.2024.03.015.

[36] ACER, European Union Agency for the Cooperation of Energy Regulators, 2025. Progress of EU Electricity Wholesale Market Integration. Report.

[37] European Commission, 2024. Consolidated text: Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable fuels of non-biological origin.

[38] European Commission, 2025. Commission Delegated Regulation of 8.7.2025 supplementing Directive (EU) 2024/1788 of the European Parliament and of the Council by specifying a methodology for assessing greenhouse gas emissions savings from low-carbon fuels. Draft.

[39] Red Eléctrica de España, 2025. Esios online platform. https://www.esios.ree.es/en#.

[40] Agora Industry and Umlaut, 2023. Levelised Cost of Hydrogen: Making the Application of the LCOH Concept More Consistent and More Useful.

[41] Özdemir, Ö, Hobbs, B.F., van Hout, M., Koutstaal, P.R., 2020. Capacity vs Energy Subsidies for Promoting Renewable Investment: Benefits and Costs for the EU Power Market. Energy Policy, vol. 137, art. 111166.