ASSESSING THE IMPACT OF LOW-CARBON HYDROGEN REGULATION IN THE EU

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Overview

Achieving the Paris Agreement's objective of limiting global temperature rise to 1.5°C and attaining net-zero emissions necessitates effective decarbonization options, among which hydrogen emerges as a pivotal solution [1], [2]. Recognizing this imperative, the European Union (EU) has set ambitious hydrogen targets through regulatory measures, underscoring hydrogen's role in the energy transition [3-4]. while the potential role of "low-carbon" hydrogen to decarbonize the economy is recognized, the hydrogen economy is struggling to take off. More than 600 projects have been announced in the EU, but only 10% advanced to final investment decision stage [5]. To kick-start the hydrogen economy, Hydrogen production costs must be kept sufficiently low to stimulate demand and initiate production at scale, which in turn supports the deployment of necessary infrastructure. However, this expansion must not come at the cost of increased emissions. This is where regulation plays a crucial role, it can help manage the trade-off by guiding investments toward low-emission hydrogen production methods. The regulation shapes the market development, the costs and can lead to decrease of CO_2 emissions. [6-8]

This paper contributes to the literature by addressing regulatory uncertainties essential for achieving climate targets and kick-starting the hydrogen economy. It provides insights into the EU hydrogen market, including grid-based and gas-based production pathways. We examine how regulatory frameworks impact overall system-level emissions, production costs, supply chain competition and hydrogen production volumes. Specifically, we analyze the impact of CO_2 accounting for grid-based electrolytic hydrogen and the CO_2 thresholds defining low-carbon hydrogen on cost-optimal production strategies, leading to policy recommendations.

Methods

We couple two models: an electricity market model that represents the future European electricity system, including hydrogen production and exchange (hereafter, electricity model) and an international hydrogen trade model that incorporates hydrogen imports and gas production (hereafter, import model) and is an adaptation of [9]. The modelling allows to comprehensively assess the economics and competition between the different production routes of clean hydrogen and accounts for variations in technology costs, energy economics, hydrogen infrastructure, and demand across different years.

Our analysis models the period from 2030 to 2050 in five-year intervals, employing an iterative approach without assuming perfect foresight, with an hourly resolution. We assume an exogenous hydrogen demand for each country of the EU that must be met at each timestep. Our modelling framework represents the demand and supply balance of electricity and hydrogen at the country level in the EU and includes trade flows from potential exporting countries outside the EU.

Electricity Model. This model is a linear programming model of the electricity market which optimizes system operations and capacity expansion under a total system cost minimization. The electricity model is an energy system capacity expansion and economic dispatch that optimizes the electricity system investment, retirement, operational decisions to minimize the global costs of the system for each year between 2030 and 2050 with a 5-years timestep. The model formulation is designed to replicate the investment and operational outcomes by a benevolent social planner, while being subject to physical and policy constraints. The results can be interpreted as the ones emanating from a pure and perfectly competitive electricity market. It is composed of two linked modules. The first one, the power module incorporates investment and operations decisions by modelling the equilibrium between the electrical demand and the production, it represents the day-ahead commitment of each power plant unit based on their marginal costs and technical constraints. The market price is deduced from the marginal value of the supply and demand constraint. The second one, the hydrogen module, models the equilibrium between hydrogen demand and hydrogen production. As one production route considered for hydrogen production is grid-based electrolysis, the hydrogen module is linked to the power module through the electrical load of the grid-connected electrolyzers.

Import model. The import model investigates the prospective global hydrogen market by evaluating the renewable and low-carbon hydrogen production potential of countries outside Europe and identifying supply and trade patterns to Europe. Utilizing linear programming, the model determines the most cost-effective methods to meet hydrogen demand and generates a yearly supply cost curve for each European country, which subsequently serves as an input (parameter) for the electricity model.

Results

Our results show that the different supply routes are complementary at the EU level, and imports are required to bridge the supply gap both in the short term and long term. Grid-based hydrogen production gradually grows to a dominant share in the EU hydrogen mix thanks to global grid decarbonization, enabling the grid's carbon intensity to fall below the required threshold, while gas-based hydrogen production follows the development of CO2 infrastructure.

Considering a yearly average EF and a maximum carbon intensity of 3.38 $kgCO_2eq/kgH_2$, the average LCOH across all supply routes in the EU is of 3.62€/kgH_2 in 2030 and 2.82€/kgH_2 in 2050. In 2030, 57% of the demand is be met through domestic electrolytic hydrogen, 8% of the demand is supplied by gas-based production and 35% by import from international trades. In the long term, as CO_2 infrastructure becomes fully available and global production costs decrease, the hydrogen demand is met by 55% domestic electrolytic hydrogen, 32% gas-based hydrogen, and 14% imports.

Compared to the rigid yearly annual emission factor (EF) to count grid-based emissions, an hourly EF encourages electrolyzer operations at times when renewables or nuclear power generation dominate the electricity mix, boosting electrolytic low-carbon hydrogen production. The hourly marginal EF allows for emission reduction at the system level, entailing 16 $MtCO_2eq$ reduction over the period 2030-2050. This reduction comes at a small cost for hydrogen production, with a slight increase of the average levelized cost of hydrogen (LCOH) from 3.62€/kgH_2 to 3.66€/kgH_2 in 2030 and from 2.82€/kgH_2 to 2.89€/kgH_2 in 2050. Using an hourly average EF leads to lower emission reduction compared to the hourly marginal EF, with additional 11 $MtCO_2$ emitted over the period, while the LCOH decreases by only 1%.

Compatibility with the EU's net-zero target would require the carbon intensity threshold of "low-carbon" hydrogen to decrease from 3.38 to 1$kgCO_2eq/kgH_2$ in 2050. Adopting a decreasing threshold would yield cumulative GHG emission savings of up to 157 MtCO2eq from 2030 to 2050, as compared to a static threshold. Gas-based low-carbon hydrogen supply would then peak by the mid-2040s and accounts for only around 9% of EU hydrogen supply by 2050. It allows to achieve nearly 157 $MtCO_2eq$ over the period, leading to LCOH of 3.62€/kgH_2 in 2030 and 2.96€/kgH_2 in 2050.

Conclusions

In this article, we focus on key regulatory items critical for the deployment of the clean hydrogen economy. We evaluate scenarios with varying carbon accounting methods and thresholds for classifying hydrogen as "low carbon", analyzing their impact on emissions, production costs, and the viability of different hydrogen pathways.

Developing the low-carbon fuels regulation and certification scheme will require delicate trade-offs between multiple objectives. The regulation will have implications on (i) EU hydrogen and power GHG emissions, (ii) EU industrial competitiveness – through access to low-cost hydrogen supply, (iii) EU dependency on hydrogen and natural gas imports and (iv) on the take-off of the EU hydrogen industry. In these considerations, environmental integrity must remain at the forefront, ensuring that the hydrogen produced is genuinely low-carbon and aligns with the European Climate Law. Towards 2050, decreasing threshold is the only way to rule out any production based on fossil gas with still significant upstream emissions and from electricity grids with residual emissions.

Similarly, enforcing an hourly marginal EF leads to environmental benefits at little extra cost. It would enforce the operation of electrolyzers according to the carbon intensity of the grid, improving system flexibility and creating market opportunities that would otherwise have been blocked with an accounting method based on annual averages.

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