The EU Delegated Act on hydrogen **has arrived...**

In this article, we explore some of the insights Baringa has developed in advising our clients on the European Commission's long-awaited Delegated Act for Hydrogen.

Europe plans to consume 20 million tonnes per year of renewable hydrogen by 2030 as part of its RepowerEU proposals, aimed at reaching Net Zero by 2050 and increasing energy security in the wake of Russia's invasion of Ukraine. The Delegated Act is a crucial step in this ambition as it clarifies **what exactly makes renewable fuel *renewable*** by setting standards on how carbon intensive the supply chain – and in particular the production method – can be. This standard gives hydrogen producers the clarity they need to **optimise their project concepts** design around those rules and is a major policy step in unlocking the 20 mt of renewable hydrogen consumption the EU envisages. However, as most carbon emissions are either already or soon-to-be regulated within the EU, there is concern among industry participants that further regulating hydrogen is a step too far and imposes unfair restrictions on one part of the energy system.

Below we outline what these restrictions are and make the case that:

- The Emission Trading System (ETS) cap prevents electrolysis from increasing CO^2 emissions, and the requirements imposed by the Delegated Act could increase the carbon intensity and cost of hydrogen production
- In particular, the 'additionality' requirement will become increasingly hard to define in a defensible way and could lead to market distortions. If applied it should apply to all new electricity demand, not just electrolysers
- Spatial matching mistakenly assumes that it's good to locate production close to demand, and cross-sector impacts require more careful consideration

The Delegated Act's three pillars of renewable hydrogen: additionality, temporal correlation and geographical correlation

The draft laws have three key criteria hydrogen producers must meet to be deemed renewable, all of which are intended to reduce the risk that the targeted 80–100 GW wave hydrogen electrolysers built in the EU between now and 2030 slow down the decarbonisation of the power system:

1. Additionality	2. Temporal correlation	3. Geographical correlation
This means new hydrogen projects should support new renewable electricity projects unless the power system in question already runs on >90% renewables. The intent is to ensure building of renewable power keeps pace with building of electrolysers that draw on that power.	This means the hydrogen production from an electrolyser must be correlated to the output from the renewable power plant that is has contracted with. Hydrogen projects built after 2027 need to correlate their output to the hour, while projects built before 2027 need only correlate monthly. The intent is to prevent the electrolyser from drawing on the grid when renewable output is low and more fossil fuels are needed.	This means electrolysers and their renewable electricity sources must be in the same 'market' or price zone. Mostly this means building them in the same country. The intent is to avoid false economies where the 'saving' from building renewables in cheap locations (e.g. Spain) to serve high-demand areas (e.g. Germany) results in added congestion and cost to the electricity network, which has finite capacity to move electricity across borders.

How much do we think these constraints matter?

Whilst we welcome the positive intent behind the European Commission's proposals, we think there is a risk they could increase the cost of producing hydrogen via electrolysis with no benefit in terms of carbon emissions.

To illustrate this risk, we use Baringa's pan-European electricity model to assess the impacts of the proposals on the **production cost** and **carbon intensity** of the **additionality and temporal correlation** criteria. We estimate the levelised cost of hydrogen and resulting cost of carbon across **three scenarios**, using hydrogen produced and consumed in **Germany*** using **offshore wind** as an illustrative example.

The first "**Unrestricted and unhedged**" scenario allows the electrolyser to run solely in response to wholesale electricity market price, identifying the optimal running profile at which the levelised cost of hydrogen is minimised taking account of both capital and operating costs.

In the "**Additionality + temporal correlation**" scenario, where additionality is applied through contracting a renewable PPA equivalent in capacity to the electrolyser at a cost (or 'strike price') equivalent to the levelised cost of electricity (LCOE) of the renewable generator and the generator is not allowed to take additional power from the grid.

The **"Additionality, no temporal correlation" scenario** allows the electrolyser to take the power output from the renewable PPA, as in the **"Additionality + temporal correlation" scenario**, but can top this up with electricity from the grid if the day-ahead wholesale power price is below a €20 / MWh price trigger threshold.

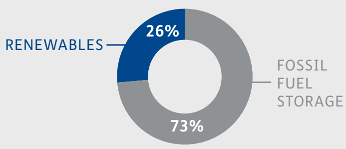
To gauge the impact of these criteria, we assess (i) **cost of hydrogen *as produced*** from the electrolyser, and (ii) the **cost of carbon** associated with drawing power from the grid associated with the electrolysers running profile. The latter captures the fact that if the electrolyser runs when there is a higher share of fossil fuel power in the grid, it should have a higher cost of carbon associated.

Our analysis (see infographic) shows that **both the cost and the carbon intensity of electrolytic hydrogen production is lower when the electrolyser operates without constraints** and can optimise against wholesale prices. Requiring both **additionality and temporal correlation increases the cost of hydrogen by 30%, and the carbon intensity by over 80%**. The cost of hydrogen storage – which has not been considered here as it is less certain what the cost will be – will add further costs to more uneven loads, particularly where there is a seasonal imbalance between supply and demand.

	OPTIMAL REGIME: LOAD FACTOR	OPTIMAL REGIME: POWER PRICE	AVG. GRID CARBON INTENSITY OF ELECTROLYSER LOAD	ELECTROLYSER ECONOMICS: PRODUCTION	ELECTROLYSER ECONOMICS: CARBON	ELECTROLYSER ECONOMICS: TOTAL
ADDITIONALITY + TEMPORAL CORRELATION Electrolyser follows wind load by the hour	42%	€49 / MWh	136 kg CO^2 / MWh	3.7	1.0	4.7
ADDITIONALITY ONLY Electrolyser follows wind load but can top up with grid power	50%	€44 / MWh	127 kg CO^2 / MWh	3.2	0.9	4.1
UNRESTRICTED AND UNHEDGED Electrolyser responds to hourly grid prices	38%	€37 / MWh	75 kg CO^2 / MWh	3.1	0.6	3.6

ASSUMING €630 / kW CAPEX, FINANCED OVER 15 YEARS

USING €49 / MWh GERMAN OFFSHORE WIND PPA + IN 2030 WHEN GRID IS 73% RENEWABLE POWER



The analysis uses Baringa's reference case hourly power price projections for Germany. Baringa's power price projections are one of small number of 'bankable' projections that are trusted by infrastructure financiers used to underpin power asset debt and equity financing. The reference case is the market scenario which most closely represents current policy and stated ambition with regards to power system capacity mix and is typically either aligned with or more conservative than National Energy and Climate Plans with respect to growth of wind and solar generation capacity. 2030 is used for the hourly price series as it represents a time horizon that is a) beyond the proposed grandfathering date and b) can be compared against other capacity mix projections and NECP targets.

Electrolyser capex, efficiency and opex assumptions have been taken from Lazard and are based on 100 MW electrolyser capacity operating at 67% efficiency. We assume grid costs and environmental levies imposed on power consumers are exempted for electrolysers and we do not account for any revenues accruing from the electrolyser providing grid ancillary services.

Lesson 1: The ETS cap prevents electrolysis from increasing CO² emissions.

Grid electricity used to produce H2 in the EU is within the EU ETS, which has a fixed cap on emissions which declines in line with the EU's long-term targets. Therefore, any increase in electricity demand from **grid-connected electrolysis cannot lead to an increase in CO²** emissions within the EU – it will simply cause increased demand for EUAs. All else being equal, this will lead to an increase in the price of EUAs. **All electrolytic-H_2 produced in the EU from grid electricity is therefore inherently low carbon,** as it has not resulted in any increase in carbon emissions compared with the counterfactual. 'Additionality' requirements for electrolysers are effectively an **additional carbon tax on hydrogen producers**, which is not faced by other electricity users (such as data centres, bitcoin miners or electricity-intensive industries). It could be seen to represent a form of **cross-subsidy from electrolysers to GHG-emitting plants** within the EU ETS (e.g. coal power plants, large industrial emitters) – the electrolyser is being required to fund additional emissions savings, which will reduce the price of EUAs to the benefit of polluting industries.

Temporal correlation requirements could increase the carbon intensity and cost of hydrogen production.

Half-hourly wholesale prices are strongly correlated with the carbon emissions intensity of the electricity system, whereas the generating profile of any individual low-carbon asset will be less well correlated. From a carbon perspective, it is therefore better to optimise operation against wholesale prices in the market where your asset is located, rather than seeking to match the electrolyser's load with the output of specific renewable assets.

This effect is demonstrated by our analysis: requiring the electrolyser to follow the output of a particular renewable technology (offshore wind in our example) increased the LCOH by €0.9 / kg H_2 (30%), and the carbon intensity of electricity used for hydrogen production by 61 kg / MWh (80%).

This occurs because the electrolyser is restricted to following renewable output during some periods where prices and grid carbon intensity are low, but generation from offshore wind is also low (a mild, still Sunday in May), and vice versa when prices, grid carbon intensity and wind output are high (a windy weekday in January). Similar results have been seen in analysis by Ruhnau & Schiele (2022, 'Flexible green hydrogen', Econstor).

Note that in our analysis, the electrolyser follows the generating profile of the overall offshore wind fleet, whereas in practice the Commission's requirement would be to follow the profile of individual renewable assets, which would be even less well correlated with grid carbon intensity and wholesale prices. This could be partially mitigated through combining solar and wind projects in those (few) regions where this is possible, but this would still not fully offset the impact.

We therefore believe that a carbon **intensity limit would be a more effective way of classifying 'green hydrogen'** than a requirement for temporal matching with specific assets. This could be based on the carbon intensity of the grid electricity used for hydrogen production, measured on an hourly granularity. Our analysis suggests that carbon intensity will be minimised simply by operating the electrolyser in a way that minimises the LCOH production, although there is a risk that government support schemes might incentivise electrolyser operation at higher load factors than this, which could increase the carbon intensity of electricity used.

Lesson 2: ‘Additionality’ will become increasingly hard to define and could lead to market distortions. If applied it should apply to all new electricity demand, not just electrolysers.

The policy and market arrangements used to incentivise deployment of renewables vary significantly between member states. In recent years, the falling costs of renewables have led to a move away from explicit subsidies in many member states towards mechanisms that provide price stability (including requirements in some countries to pay back to consumers at times of high wholesale prices), or access to leases on sites.

There are also significant differences in the policy and market frameworks in different countries, including in the types of charges that different asset types need to pay. There are likely to be further significant changes to policy, regulation and markets over the next 5-10 years, with an increasing move away from subsidy towards requirements for new renewables projects to pay back to consumers at times of high electricity prices.

This makes it very hard to define ‘subsidy’ or ‘additionality’ in a way that applies consistently across different member states and is robust enough to withstand future changes in market arrangements within and between countries. This creates a **risk that additionality requirements for electrolysers will lead to market distortions between member states.**

As an example, in the Netherlands, new offshore wind farms do not have to pay offshore grid costs, which means they stand a better chance of being financed without PPAs or government revenue support mechanisms. This means that potentially there is a larger pool of unsubsidised offshore wind projects in the Netherlands available to sign PPAs with electrolysers than in other member states, but these PPAs are not directly stimulating additional renewable deployment as the projects would have been viable to build without a PPA.

Why just electrolysers...

Additionality requirements go to the question of who should be responsible for ensuring that new low-carbon generation is developed to meet demand and carbon targets – governments and regulators, or energy consumers? In most markets, it is seen as the responsibility of governments and regulators to ensure there’s a suitable policy, regulatory and market framework to incentivise development of new generating infrastructure to meet demand.

One can just as easily argue that other large power consumers, such as data centres, bitcoin mining or electricity-intensive industries, should be more directly involved in infrastructure investment, but if so, this should be consistent across all sources of demand, not one specific sector.

In contrast, green hydrogen will be an essential vector for supporting decarbonisation of other parts of the economy, as well as providing a form of long-duration storage within the electricity sector that will facilitate integration of a higher penetration of renewables. It is therefore inconsistent and risks potentially perverse outcomes to require electrolysers to directly support new low-carbon generation but not to place the same requirements on other electricity-intensive industries.

IIn our illustrative example, the cost of additionality to production is €0.5 / kg when considering the difference in cost between the “Unrestricted and unhedged” and “Additionality, no temporal connection” scenarios. This could be even more costly in a system where existing renewables are cheaper than new ones, as is likely to be the case in the 2030s, once the share of renewables is very high in many member states and price cannibalisation of renewables coming off subsidies is a factor. For this reason, project developers may be hoping the rules on additionality are relaxed sufficiently for hydrogen producers to contract with older renewable assets.

1. Note that the tender process for offshore wind in the Netherlands means that some projects may offer below market price power to electrolysers as an incentive for winning seabed leases – thereby subsidising hydrogen production.

Lesson 3: Spatial matching mistakenly assumes that it's good to locate production close to demand, and cross-sector impacts require more careful consideration

While not analysed in our illustrative example, **spatial matching requirements may increase carbon intensity of hydrogen production** compared with optimising the location of the electrolyser and generation separately.

To minimise the cost of abatement, electrolysers (and other new sources of demand) should preferentially be in regions with the lowest grid carbon intensity – e.g. those with surplus low-carbon generating capacity. Conversely, to maximise carbon savings, new low-carbon generation should be in regions with higher grid carbon intensity – e.g. those with lower penetration of low-carbon generation. Therefore, **the ideal location of the new demand and generation is likely to be on different grid regions**, and a 'spatial matching' requirement may lead to worse outcomes in terms of the cost of carbon abatement.

Cross-sectoral interactions need to be managed with care...

Emissions from electrolytic H_2 production are within scope of the EU ETS, but the end use of green H2 will be split between multiple sectors, including those within the EU ETS (e.g. heavy industry), those in the potential 'new ETS' (road transport fuels and heating) and potentially those outside of any ETS. This creates a risk that, due to multiple and different carbon prices, price signals distort decisions about the downstream uses.

For example, if electrolytic H_2 that does not meet eligibility requirements has to pay the carbon price in the 'new ETS' for road and heating fuel, that could favour use cases that fall outside of the ETS sectors, even if these are less of a priority for decarbonisation.

If you are interested in hearing more, please get in touch with our hydrogen experts.

Alastair Davies
Alastair.Davies@baringa.com

Alex Weir
Alex.Weir@baringa.com

Nimo Bergstrom
Nimo.freitag@baringa.com

Shane Heffernan
Shane.heffernan@baringa.com

Find out more:
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