

Barnes, Alex

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How proper measurement of low carbon hydrogen's carbon intensity can reduce regulatory risk

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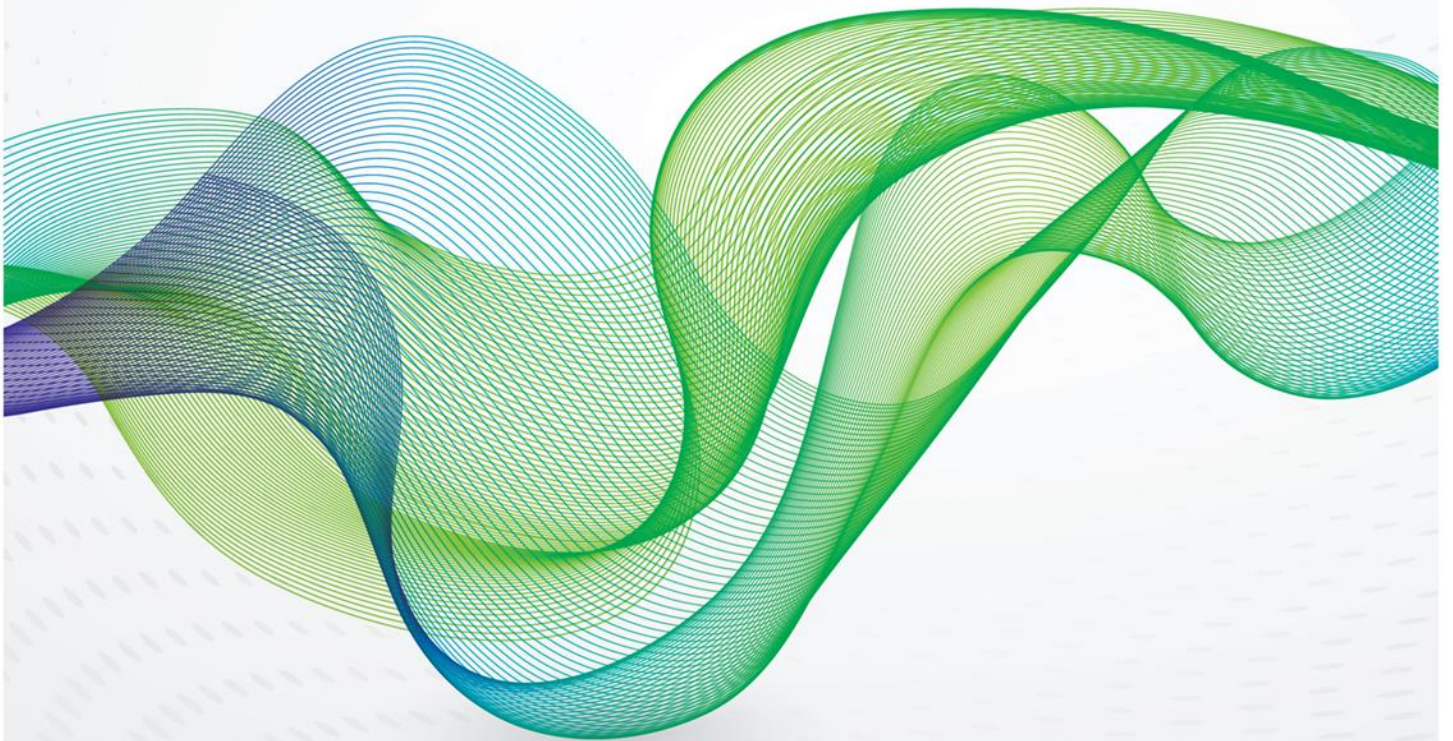
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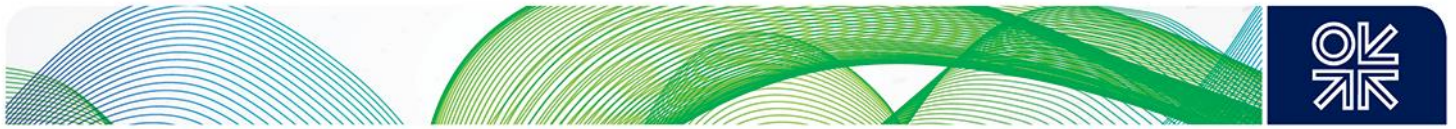
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June 2024

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Summary

Hydrogen with a low carbon intensity ('low carbon hydrogen')¹ is a means of decarbonising sectors of the economy which are not easily electrified. Hydrogen produced via electrolysis is also seen as a way of storing variable renewable electricity generated by wind or solar, and thereby overcoming some of the problems associated with intermittent renewable electricity generation. Key issues for policy makers are the high cost of low carbon hydrogen and its carbon intensity. Both vary considerably dependent on the production pathways used.

The dividing line between electrification and low carbon hydrogen as a means of decarbonisation is not clear cut. Technologies are evolving and there remains considerable uncertainty about how much hydrogen will be used and by which sectors. Electrolytic hydrogen is a less efficient use of electricity because of the conversion losses. Concerns that low carbon hydrogen may be a scarce resource mean that governments need to know not just that they are enabling deployment of low carbon hydrogen at the lowest cost (\$/kgH₂) but also that they are achieving the best result in terms of reduction of emissions (tCO₂abated/kgH₂) which will depend on the end use of the hydrogen as well as the hydrogen's low carbon intensity. Producers need to know that they comply with government definitions of low carbon hydrogen, whilst users need to show they are reducing emissions, and that they are doing this at lowest cost.

The current nomenclature based on colour or broad terms such as 'clean' or renewable are inadequate as they do not give any indication of the carbon intensity of the hydrogen, which is the key metric from a decarbonisation perspective. Different definitions with different carbon accounting mean it is difficult to compare either the cost of the hydrogen (\$/kgH₂) on a like for like basis, or the relative cost of emissions avoided for hydrogen (\$/tCO₂abated/kgH₂).

Calculating hydrogen's carbon intensity depends on the emissions included in the calculation (system boundary and scope) and this differs between jurisdictions. There are also different methodologies for calculating the emissions included. Upstream emissions include the production of any feedstocks (e.g. oil, natural gas, biomass including biogas, coal) and its processing and transportation to the hydrogen production plant. Upstream emissions will depend on the type of feedstock, the method and efficiency of production, and the distance, method and efficiency of transportation to the hydrogen production plant. The carbon intensity of feedstocks is likely to be very source specific.

Emissions from hydrogen production will be determined by the production process used and the energy used in that process. Electrolysers and CCS based technologies have different production efficiencies, costs and carbon capture rates. The key determinant of electrolytic hydrogen's carbon intensity is the carbon intensity of the electricity used. Renewable electricity is zero emissions but its intermittency results in higher Levelised Cost of Hydrogen (LCOH) due to lower electrolyser load factors. However, the carbon intensity of grid electricity varies considerably between countries based on the generation mix.

Electricity has to be balanced in real time i.e. the amount of electricity generated and supplied to the grid must equal the amount taken from the grid at any given moment to maintain system stability. Thus, the carbon intensity of hydrogen using grid electricity depends on the carbon intensity of the grid at the same time as hydrogen production. Additional demand from electrolysers can result in higher grid emissions if it results in more fossil fuel generation being used but electrolysers can help balance the grid by using 'surplus' renewable electricity which might otherwise be curtailed.

Temporal correlation measures the carbon intensity of hydrogen based on the electricity used in a given time period (e.g. half hour, hour, month, year). A shorter time period will more accurately reflect the requirement that electricity grids balance in real time, and that the carbon intensity of hydrogen is based on the carbon intensity of the electricity generated and used at the time of hydrogen production. Use of looser correlation rules in the EU, such as monthly correlation or system averaging, results in hydrogen production with carbon intensities which can be higher than high carbon hydrogen or fossil fuels. It

¹ In this paper low carbon hydrogen is defined as hydrogen with a significantly lower carbon intensity than hydrogen based on fossil fuels without CCS. Similarly low carbon electricity is defined as electricity significantly lower carbon intensity than electricity based on fossil fuels without CCS. Low carbon electricity therefore includes renewables (e.g. wind, solar, hydro, geothermal, biomass), nuclear and fossil fuel generation with CCS.

allows EU countries with much higher grid and hydrogen carbon intensities to meet EU requirements alongside those countries which have very low carbon intensities. The effect is magnified by the gearing effect of electrolyser efficiency. The least efficient electrolyser in Sweden using grid electricity still has a lower hydrogen carbon intensity than the most efficient electrolysers using grid electricity in all the other countries except France. The higher the carbon intensity of electrolytic hydrogen today, the more zero carbon electricity will be needed in future to remove emissions in future if negative emissions are required to remain within a carbon budget.

The impact of different temporal correlation periods varies considerably based on the grid. A US study² looking at the impact of hourly, weekly and annual correlation on grids in the western interconnection electricity system found looser correlation resulted in higher emissions but the LCOH was not necessarily proportionately higher. Allowing interaction between electrolyser projects and the grid can result in lower grid emissions, as shown by a study looking at the impact on hydrogen project design and economics, and power sector emissions using historic German electricity data.³ Using the study's data it can be seen that hourly correlation results in a higher LCOH but a greater reduction in emissions and at lower cost of emissions saved. Using data from a study on how to optimise low carbon hydrogen production at a Danish energy park,⁴ higher LCOH as a result of greater investment in renewable generation has a lower LCOH per kg of emissions reduction compared to only using Danish grid electricity.

Low carbon hydrogen faces high regulatory risk because it is entirely dependent on government intervention – whether subsidies or targets – to support its business case. It therefore needs to demonstrate that is good value for money in terms of reducing emissions. Proper accounting of carbon intensity using hourly correlation of the inputs is required as different rules give a misleading picture of the true cost of emissions reduction, and hence can lead to a misallocation of resources. A higher LCOH does not necessarily mean a high cost of emissions reduction. Stricter temporal correlation can also enable better integration between electrolyser and the grid, which can result in a lower LCOH and reduction in grid emissions. It could also lessen the need for additional requirements as electrolysers will have an incentive to ensure that any grid electricity they use is low carbon intensity. Strict temporal correlation rules combined with sliding scale support based on the carbon intensity of low carbon hydrogen, enable a simplification of the rules which reduces regulatory uncertainty for projects, both in terms of understanding the current rules, and the risk of future rule changes.

Proper comparison of low carbon hydrogen produced in different countries requires a common methodology for measuring emissions along the value chain, and a common nomenclature based on carbon intensity to avoid the confusion over terms. The common methodology could be based on the IPHE Methodology for Determining the Greenhouse Gas Emissions Associated with the Production of Hydrogen. This would still enable countries to set their own carbon intensity thresholds, the level of support to provide and how to provide it.

The reason d'être for low carbon hydrogen is that it will assist governments in their efforts to decarbonise their economies. This in turn depends on the cost effectiveness of low carbon hydrogen in doing so. If low carbon hydrogen fails to demonstrate this it risks losing the government support it needs for companies to invest in the sector, a major source of regulatory risk. Markets are best placed at managing those risks that can easily be internalised – financial costs, project implementation – but are less able to deal with externalities such as GHG emissions. Governments can enable markets to bring down the cost of low carbon hydrogen by providing a stable and clear regulatory framework. Crucially this includes proper accounting of low carbon hydrogen's carbon intensity, alongside common accounting standards and nomenclature. Only rigorous accounting standards, backed up by flexible government support based on carbon intensity, will enable investment in low carbon hydrogen supply, infrastructure and demand where it makes the most sense - both financially and environmentally.

² Ricks, Xu, Jenkins (2023) 'Minimizing emissions from grid-based hydrogen production in the United States.' Environmental Research Letters. Wilson Ricks et al 2023 Environ. Res. Lett. 18 014025

³ Ruhnau, Schiele (2023) 'Flexible green hydrogen: The effect of relaxing simultaneity requirements on project design, economics, and power sector emissions.' Energy Policy.

⁴ Sorrenti, Zheng, Singlitico, You (2023) 'Low-carbon and cost-efficient hydrogen optimisation through a grid connected electrolyser: The case of Green Lab Skive.' Renewable and Sustainable Energy Reviews.



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1. Introduction

In recent years there has been an increasing focus on the use of hydrogen with a low carbon intensity ('low carbon hydrogen') as a means of decarbonising sectors of the economy which are not easily electrified. Hydrogen produced via electrolysis is also seen as a way of storing variable renewable electricity generated by wind or solar, and thereby overcoming some of the problems associated with intermittent renewable electricity generation. There is already a significant hydrogen market where hydrogen is used in the oil refining process, or in the manufacture of chemicals and fertilisers. However virtually all this hydrogen is produced with a very high carbon intensity, and therefore not suitable as a means to decarbonise hard to electrify industry.⁵ It is therefore essential to differentiate between existing high carbon intensity hydrogen and low carbon hydrogen. The carbon intensity of low carbon hydrogen can also vary considerably depending on production pathway and the inputs used.

Low carbon hydrogen is a means (but only *a* means not *the only* means) to reduce Greenhouse Gas (GHG) emissions. Low carbon hydrogen is more expensive than the fossil fuels it is intended to replace, so government intervention of some form is required to encourage or mandate its use as a way of meeting decarbonisation targets. Low carbon hydrogen therefore has to compete with both existing fossil fuels and other means of decarbonisation. Governments will want to ensure that where it is used, low carbon hydrogen will result in the most cost-effective decarbonisation of the economy. They can only do this if they know not only the cost of hydrogen, but also its carbon intensity, and hence the cost of emissions reduction for each kg of hydrogen. The same applies to companies who may be considering using low carbon hydrogen.

The requirement for government support or intervention means that low carbon hydrogen is subject to potentially high levels of regulatory risk (e.g. changes in levels of government support) and uncertainty (e.g. confusing or different rules in different jurisdictions). This paper examines the challenges facing stakeholders with regards to understanding hydrogen's carbon intensity; the confusing nomenclature applied to low carbon hydrogen; and the impact that different approaches to measuring carbon intensity can have on hydrogen costs and its actual carbon intensity. It then proposes ways in which regulatory risk can be reduced.

2. Challenges for stakeholders

Governments, producers and users all have an interest in a clear regulatory framework for low carbon hydrogen. As the case for low carbon hydrogen rests on its ability to decarbonise sectors which cannot be easily electrified with low carbon electricity, the carbon intensity of low carbon hydrogen is key, alongside its cost relative to both other decarbonisation solutions and current unabated fossil fuel use.

2.1 Policy makers

Policy makers face two key challenges concerning low carbon hydrogen:

- Its high cost compared to current hydrogen production and compared to the fossil fuels it aims to replace.
- Its carbon intensity and hence its ability to contribute to decarbonisation targets.

The IEA reports a range of costs for low carbon hydrogen depending on production pathway and location. Based on 2021 costs the IEA quotes a range of 1.0 to 3.0 USD/kg for hydrogen based on fossil fuels (natural gas reforming or coal gasification) without CCS, 1.5 to 3.6 USD/kg for fossil fuel based hydrogen with CCS, and 3.4 – 12 USD/kg for electrolysis using low emission electricity.⁶

⁵ Decarbonising existing hydrogen use should be a relatively easy policy goal as demand for the hydrogen already exists, and therefore does not require the same degree of change as companies which will need to switch from fossil fuels to hydrogen.

⁶ IEA (2023), *Global Hydrogen Review 2023*, IEA, Paris, Licence: CC BY 4.0. Pages 88 to 89.



There is also a wide range of carbon intensities for different hydrogen production pathways. The figures below also include upstream emissions associated with inputs such as the production and transportation of natural gas, coal or nuclear fuels. Based on IEA figures⁷ these are summarised in the table below:

Table 1: Carbon intensity of different hydrogen production pathways

	Range of carbon intensity (kgCO _{2e} /kgH ₂)
Steam Methane Reforming without CCS	10 – 13
Coal gasification without CCS	22 - 26
Steam Methane Reforming with CCS*	1.5 – 6.2
Coal gasification with CCS*	2.6 – 6.3
Electrolysis from grid-based electricity	0.5* – 24.0***
Nuclear electricity	0.1 – 0.3

*Assumes 93% capture rate

**Based on Swedish grid carbon intensity of 10g CO_{2e}/kWh.

***Based on global average carbon intensity of 460g CO_{2e}/kWh. In grids with carbon intensity above the global average the carbon intensity of hydrogen will be higher.

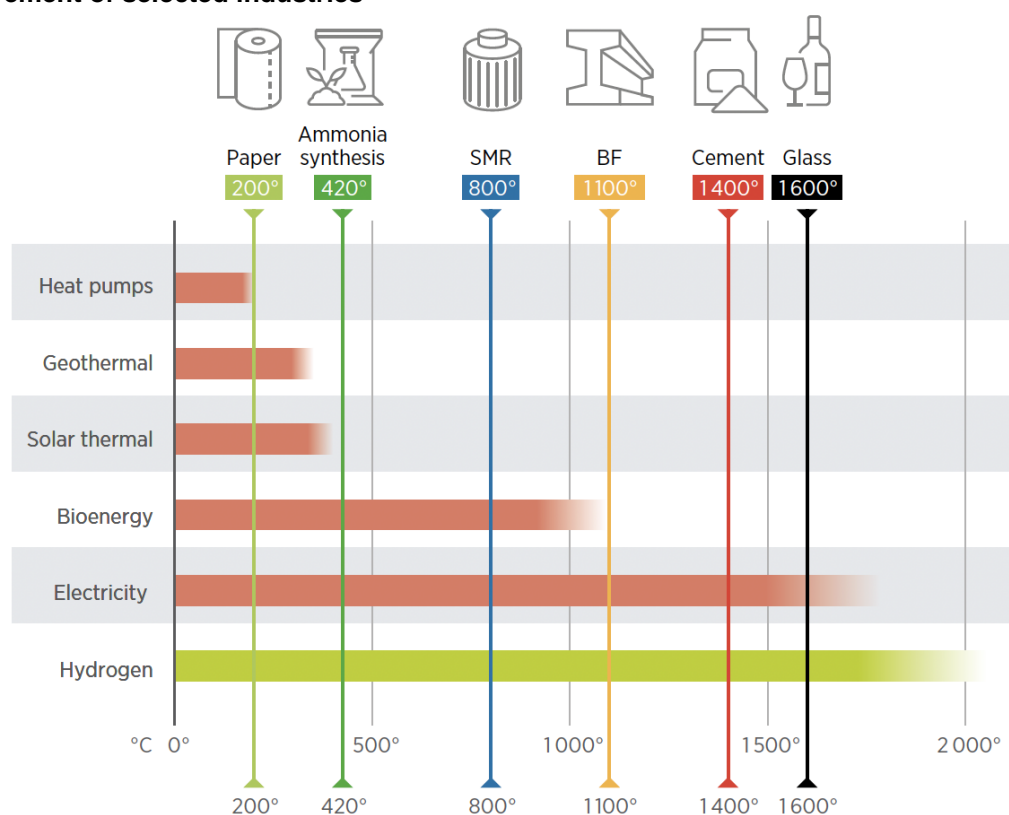
Government interventions to support low carbon hydrogen include mandatory targets such as the EU requirement that 42% of hydrogen used in industry by 2030 is based on renewable electricity (Renewable Fuels of Non-Biological Origin - RFNBOs), the UK subsidies for 'low carbon hydrogen' under the Hydrogen Production Business Model, or the US 45 V tax credits for 'clean hydrogen' under the Inflation Reduction Act.

The dividing line between electrification and low carbon hydrogen as a means of decarbonisation is not clear cut. Technologies are evolving and there remains considerable uncertainty about how much hydrogen will be used and by which sectors. IRENA notes that a 'range of options to produce high-temperature heat via electricity (with resistance, infrared, induction, microwave and plasma heating) exists and may be more energy-efficient than the burning of green hydrogen'.⁸ Figure 1 below compares different end use applications and their heat requirements compared to different sources of energy.

⁷ Ibid.

⁸ IRENA (2022) *Green hydrogen for industry. A guide to policy making*. Page 12.

Figure 1: Working temperatures for selected renewable heat technologies and temperature requirement of selected industries



Source: IRENA (2022), [Green hydrogen for industry: A guide to policy making](#), International Renewable Energy Agency, Abu Dhabi. Figure 1.3 Working temperatures for selected renewable heat technologies and temperature requirement of selected industries.

Hydrogen is also seen as a means of storing surplus renewable electricity until it is required. Obvious competitors for this include pumped hydro⁹ and batteries, whether utility or household scale. Other potential competitors include thermal storage. All these competing technologies have their advantages and disadvantages and different costs. Governments may not be best placed to decide in advance which technologies are most suitable given that many, like low carbon hydrogen, are not yet widely deployed.

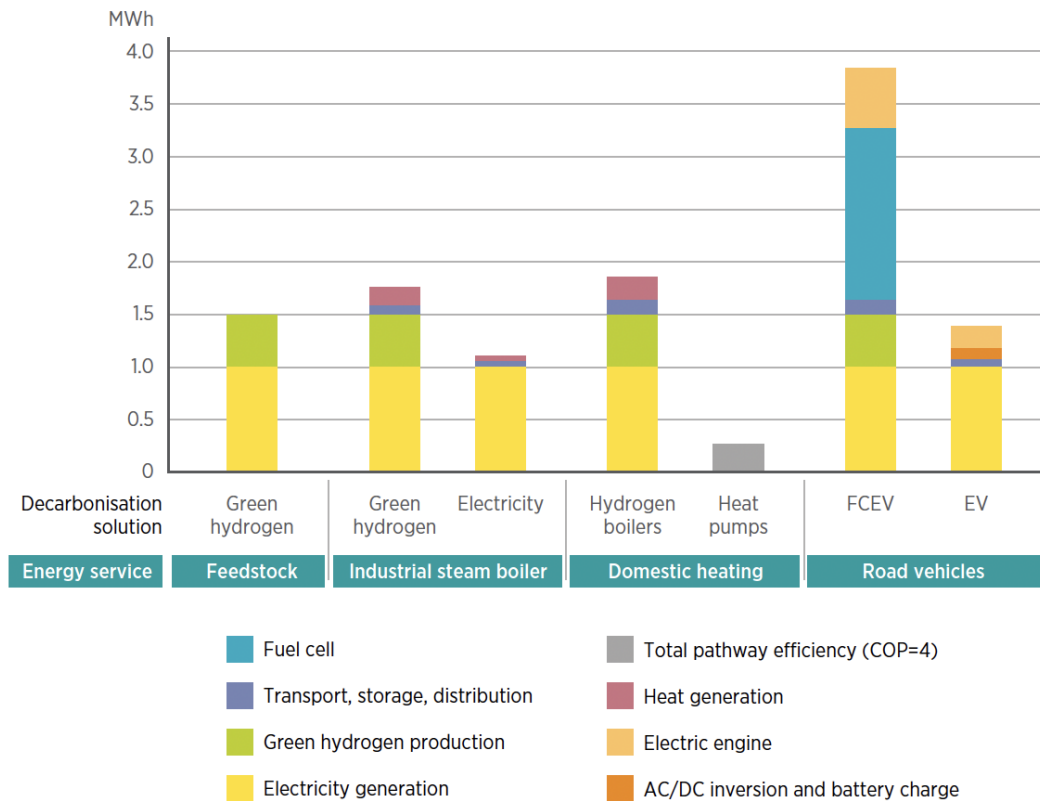
Electrolytic hydrogen not only competes with renewable electricity as a means of decarbonising certain end use sectors, but it may also compete with those end use sectors as a source of demand for renewable electricity itself, where the electrolyser's load factor is maximised. It can also benefit system efficiency if electrolysers utilise renewable electricity which would otherwise be curtailed, but this may reduce the electrolyser's load factor. Moreover, electrolytic hydrogen is a less efficient use of electricity because of the conversion losses. Whilst 1 kWh of renewable electricity can directly replace 1 kWh of fossil fuel fired electricity used to meet current demand, 1 kWh of renewable electricity will produce less than 1 kWh of usable hydrogen. IRENA says that "when electricity based alternatives are available the electrical efficiency pathway metric can be used to assess how much more electricity the use of hydrogen would entail compared to direct electrification. This can inform policy makers on the estimated additional power capacity needed to power a certain sector with green hydrogen."¹⁰ IRENA illustrates the point with Figure 2 comparing different uses of electricity and electrolytic hydrogen.

⁹ Electricity is used to pump water into an uphill reservoir at times of low electricity prices, and the water is released to generate electricity when prices are high.

¹⁰ IRENA (2022) [Green hydrogen for industry. A guide to policy making](#). Page 13.



Figure 2: Estimation of renewable electricity generation needed for 1 MWh by energy services and by transformation pathway



Source: IRENA (2022), [Green hydrogen for industry: A guide to policy making](#), International Renewable Energy Agency, Abu Dhabi. Figure i.3 Estimation of renewable electricity generation needed for 1 MWh by energy services and by transformation passage

Note: COP = coefficient of performance; EV = electric vehicle, FCEV = fuel cell electric vehicle

It takes time to decarbonise electricity grids via the deployment of low carbon electricity (nuclear or renewables) and the share of renewable energy on the grid also depends on the growth of demand relative to supply. If electrolyzers are competing for limited low carbon electricity, the deployment of electrolyzers may help or hinder decarbonisation of the grid (discussed in more detail below).

Governments will want to ensure they decarbonise their economies as quickly and as cheaply as possible. The former matters because every tonne of CO₂ emitted today uses up the carbon budget which means there is less time for the deployment of newer decarbonisation technologies before the threshold for 1.5C or 2.0C warming is met.¹¹ Once the threshold is exceeded, the need for carbon removals increases to bring the CO₂ in the atmosphere back down below the acceptable threshold – which in turn requires investment in either more renewable energy to power Direct Air Capture (DAC) or greater deployment of Bioenergy with Carbon Capture and Storage (BECCS) than otherwise be the case. In turn this raises increased feasibility and sustainability concerns¹² as DAC is itself a new and

¹¹ “Cumulative carbon emissions until the time of reaching net zero CO₂ emissions and the level of greenhouse gas emission reductions this decade largely determine whether warming can be limited to 1.5°C or 2°C (high confidence). . . If the annual CO₂ emissions between 2020–2030 stayed, on average, at the same level as 2019, the resulting cumulative emissions would almost exhaust the remaining carbon budget for 1.5°C (50%), and deplete more than a third of the remaining carbon budget for 2°C (67%)” IPCC, 2023: Summary for Policymakers. In: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland, pp. 1-34, doi: 10.59327/IPCC/AR6-9789291691647.001. Paragraphs B.5 and B.5.3

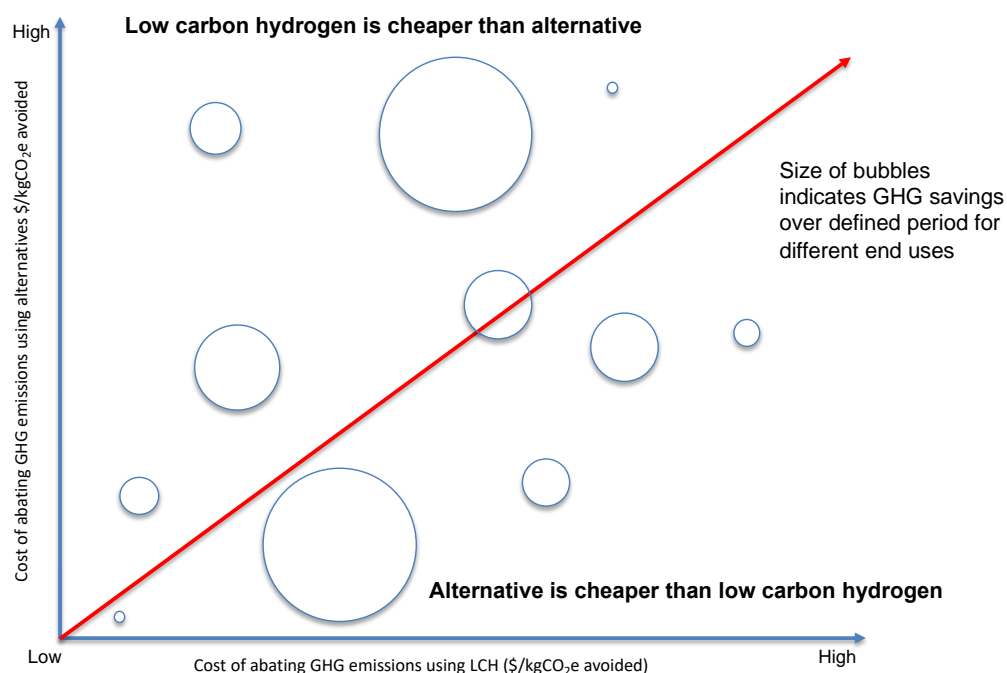
¹² Ibid. Paragraph B.7. “If warming exceeds a specified level such as 1.5°C, it could gradually be reduced again by achieving and sustaining net negative global CO₂ emissions. This would require additional deployment of carbon dioxide removal, compared to pathways without overshoot, leading to greater feasibility and sustainability concerns.”

costly technology, and there are limits on the availability of suitable biomass feedstocks for BECCS. DAC also requires large amounts of energy.¹³

There are concerns that low carbon hydrogen may be a scarce resource – limited by either the availability of low carbon electricity or Carbon Capture and Storage (CCS) infrastructure – and thus hydrogen use should be focussed on those sectors which need it most. Therefore, governments need to know not just that they are enabling deployment of low carbon hydrogen at the lowest cost (\$/kgH₂) but also that they are achieving the best result in terms of reduction of emissions – tCO₂abated/kgH₂ which will depend on the end use of the hydrogen as well as the hydrogen’s low carbon intensity. For example, replacing coke in steel making with hydrogen in a Direct Reduction of Iron (DRI) process will result in very high carbon abatement because of the high carbon intensity of coke. Replacing natural gas with hydrogen in high temperature heat may result in less carbon abatement because of the lower carbon intensity of natural gas but much will depend on the efficiency of the different processes used and the carbon intensity of the low carbon hydrogen itself.

Where supporting particular applications the potential reduction in emissions over a given time period is also a consideration, particularly if hydrogen demand requires investment which is time constrained e.g. when companies are considering the replacement of existing equipment. Large scale capital investments such as steel plants have long asset lives so it makes sense to convert to hydrogen at the appropriate point in the investment cycle. The trade-offs facing government can be illustrated in Figure 3 below.

Figure 3: Illustration of trade-offs between using low carbon hydrogen or other technologies to decarbonise



Lastly governments need to be able to compare hydrogen produced in different regions. International trade in low carbon hydrogen is seen as a way of connecting areas with plentiful low-cost renewables with those areas which need low carbon hydrogen. If importing governments are subsidising imports – for example bridging the gap between the imported cost of low carbon hydrogen and the cost of fossil fuel alternatives – they will need to know the carbon intensity of the imported hydrogen. They will also want to avoid ‘carbon leakage’ whereby lower carbon intensity hydrogen (or derivatives such as ammonia) is replaced by higher carbon intensity hydrogen imports, or industry which uses hydrogen such as chemicals moves abroad.

¹³ DAC requires between 6.6GJ and 9.5GJ of energy to capture one tonne of CO₂. Source: [IEA Direct Air Capture](#).

To counter this the EU has implemented a Carbon Border Adjustment Mechanism (CBAM) whereby eventually specific imported goods will have to show that they have already paid a carbon price equivalent to the EU ETS price for their GHG emissions via a carbon tax or ETS in their home jurisdiction, or they will have to pay for certificates to import their goods into the EU. The aim is that imports do not have a price advantage over indigenous production. Hydrogen was a last-minute addition to the CBAM mechanism which is being phased in between 1st October 2023 and 1st January 2026. Other products relevant to hydrogen include iron and steel, and fertilisers (including ammonia) as these either require hydrogen as part of their production or are sources of potential hydrogen demand e.g. DRI steel production. The CBAM requires measurement of the carbon intensity of the imports including any pre-cursors used in their production if the pre-cursors are also covered by CBAM. Therefore, a key determinant of the carbon intensity of imported DRI steel will therefore be the carbon intensity of the hydrogen used in the production process.

2.2 Hydrogen producers

Ultimately government policy will drive the low carbon hydrogen market, whether it is by the imposition of mandatory targets, tax breaks or subsidies. Producers will therefore need to ensure that they comply with the government definition of low carbon hydrogen, and that they can demonstrate compliance. Producers will also need to know that their proposed methods of hydrogen production (production pathways) comply with those which governments wish to support. Whilst production pathways based on electrolysis, methane reforming or gasification have been used commercially for many decades, other pathways are either less common or are at earlier stages of development. Pyrolysis has been used to produce hydrogen before but more as a by-product of carbon black production.

The UK Hydrogen Production Business Model (HPBM)¹⁴ which provides a subsidy for low carbon hydrogen requires compliance with the UK's Low Carbon Hydrogen Standard (LCHS)¹⁵ prevailing at the time that the contract for subsidy is agreed between the government and hydrogen project. The LCHS has evolved over time, and it is version 3 which is now in place, and the government has announced the first projects to be awarded subsidy under the HPBM as part of the first Hydrogen Allocation Round (HAR 1). Whilst the principles of the LCHS have remained the same between the first and third versions of the standard¹⁶, the LCHS has become more detailed and precise as understanding of the technical issues involved in low carbon hydrogen production has developed during discussions between producers and government. Key changes include refinement of the system boundary approach, inclusion of more production pathways, and inclusion of rules covering electricity storage.

The EU has set targets for Renewable Fuels of Non-Biological Origin (RFNBOs)¹⁷ which includes hydrogen produced via electrolysis, and its derivatives. The targets are set at an EU level and its therefore up to the Member States to develop policies which enable their industry to comply with the targets. As well as the targets, the definition of RFNBO and the relevant qualifying criteria are included in the main legislation¹⁸ and delegated acts including definitions of the type of electricity that is eligible to be used¹⁹ and the GHG savings compared to a fossil fuel comparator.²⁰ Companies which are applying for support via the EU Hydrogen Bank subsidy scheme or national schemes such as the German H2 Global programme will need to meet the RFNBO criteria. However, the development of the

¹⁴ <https://www.gov.uk/government/publications/hydrogen-production-business-model>

¹⁵ <https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria>

¹⁶ The first version was published in April of 2022, the second version was published in April 2023, and the third version in December 2023.

¹⁷ Revised Renewable Energy Directive. [Directive \(EU\) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive \(EU\) 2018/2001, Regulation \(EU\) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council](#)

¹⁸ *Ibid.*

¹⁹ [The Delegated Act on a methodology for renewable fuels on non-biological origin](#). 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 liquid and gaseous transport fuels of non-biological origin

²⁰ [The Delegated Act establishing a minimum threshold for greenhouse gas \(GHG\) emissions savings of recycled carbon fuels](#). Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels.



criteria has been slow and confusing. The original delegated acts should have been in place by 31st December 2021 but did not come into force until June 2023. This was because of protracted and complicated arguments between EU Member States, producers and the EU Commission over the original criteria proposed by the Commission. In particular, the original rules governing the definition of renewable electricity were rejected as being too restrictive. Even after the delegated acts were published, there continued to be confusion which required further discussion between the Commission and producers, resulting in the publication of clarifying Questions and Answers documents in July 2023 and then again in March 2024.²¹

The rules on RFNBOs will also apply to imports from outside the EU, and the EU has explicitly stated that it expects to import half of its renewable hydrogen requirements by 2030. Support schemes such as the German H2 Global programme are aimed at imports as well as EU produced hydrogen.

Further uncertainty for potential hydrogen producers wishing to sell low carbon hydrogen in the EU is likely to arise because of the need to define 'low carbon hydrogen'²² in the EU legal context – that is hydrogen which is not an RFNBO or based on biomass but based on non-renewable energy or feedstocks such as nuclear electricity or natural gas. The main legislation establishing low carbon hydrogen, the Hydrogen and Gas Decarbonisation Package, has recently been agreed,²³ but the exact criteria will not be in place until 2025 as part of a delegated act. The Hydrogen and Gas Decarbonisation Package is already behind schedule as it was originally proposed at the end of 2021, and the use of a delegated act creates further scope for confusion and delay if the experience of the RFNBO delegated acts is any guide.

Hydrogen producers in the US are facing similar uncertainty. The Inflation Reduction Act (IRA) gives generous tax breaks for 'clean' hydrogen which is defined as hydrogen with a carbon intensity equal or below 4kgCO₂e/kgH₂. The US Treasury published proposed rules defining 'clean hydrogen' on 26th December 2023.²⁴ These have become the subject of fierce debate,²⁵ just as they did when the EU was developing its delegated acts. Written comments were due by 26th February 2024, and a public hearing was held on 25th March 2024.

The Australian government has also been developing hydrogen standards but the main driver for this is very different from the UK, EU or US. Australia sees itself as a future major exporter of low carbon hydrogen, and therefore is more interested in ensuring it has a system which enables its hydrogen producers to demonstrate the carbon intensity of the hydrogen rather than set a defined standard. The Australian approach is based on a Guarantee of Origin scheme²⁶ for hydrogen which measures the GHG intensity of hydrogen produced but it does not set an emissions intensity threshold, unlike the US, UK and EU schemes. The aim is that importers can set the GHG intensity threshold that they will allow, whilst the Australian GO system enables producers to demonstrate that they meet that standard. The Australian measurement system is designed to be compatible with the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) methodology in order to reassure importers of the validity of the scheme. The Australian system is designed to be compatible with the overall National Greenhouse and Energy Reporting (NGER) system. This means that producers and their Australian customers will be able to demonstrate how much they are contributing to decarbonisation based on the actual carbon intensity of the hydrogen produced rather than be restricted to producing or using

²¹ https://energy.ec.europa.eu/document/download/21fb4725-7b32-4264-9f36-96cd54cff148_en?filename=2024%2003%2014%20Document%20on%20Certification.pdf

²² Note the EU definition of low carbon hydrogen is more restrictive than the term low carbon hydrogen used in this paper. In this paper low carbon hydrogen would include RFNBOs, biomass-based hydrogen and hydrogen derived from non-renewable sources. See Clarifying the nomenclature.

²³ [Fit for 55: Council signs off on gas and hydrogen market package](#). Council of the EU Press release 21 May 2024

²⁴ [Section 45V Credit for Production of Clean Hydrogen; Section 48\(a\)\(15\) Election to Treat Clean Hydrogen Production Facilities as Energy Property](#). U.S Department of the Treasury Internal Revenue Service. 26th December 2023.

²⁵ For example: " 'Green' hydrogen debate heats up ahead of tax-credit decision. Leaked details about rules governing billions of dollars in hydrogen subsidies have added fuel to an already fiery debate." Canary Media 6th December 2023; "Don't let the federal governments kill green hydrogen before it gets started." Forbes 1st August 2023; "US Treasury moves to restrict hydrogen tax breaks offered by the IRA. Democratic Senator Joe Manchin says new guidance will 'kneecap' sector critical to slashing emissions." Financial Times 22nd December 2023; "We can meet the US Treasury's strict standards for clean hydrogen — others can do it too": Air Products. Hydrogen Insight 26th March 2024.

²⁶ <https://www.dcceew.gov.au/energy/renewable/guarantee-of-origin-scheme>



hydrogen which meets a set standard. First discussions were held in 2021, with further consultation and trials in 2022 and 2023. Implementation is expected to take place in 2024.

Other countries such as China, Japan and South Korea are also developing hydrogen standards. Ultimately there will be standards in all countries which have low carbon hydrogen as part of their decarbonisation efforts. The challenge for producers is keeping track of the various standards and definitions which will determine the viability of their projects.

2.3 Hydrogen users

Users face a similar challenge to that of governments, namely showing that the hydrogen they use results in lower emissions overall in the economy. Direct use of hydrogen as a fuel, whether combusted or in fuel cells, does not result in CO₂ emissions. (Combustion of hydrogen in gas turbine can lead to NO_x emissions). If final energy users were to switch from fossil fuels to high carbon hydrogen, they would simply be moving emissions from the point of use to the point of hydrogen production, or worse increase emissions overall because of process inefficiencies. Whilst much of the focus of recent efforts has been on the support of low carbon hydrogen production, without demand there is little incentive for investment in production. Future users of hydrogen face the challenges of investing in equipment to move from fossil fuels to hydrogen, for example replacing blast furnaces with Direct Reduction of Iron (DRI) for virgin steel making or enabling burners to use hydrogen instead of natural gas. Users will need to weigh up both the capital costs of the investment required and the commodity cost of the hydrogen versus alternatives.

Users are policy 'takers' i.e. the need for users to demonstrate the carbon intensity of the hydrogen they use depends on the policy framework within which they operate. In a system where GHG emissions are taxed (e.g. a carbon tax) or regulated (e.g. an Emissions Trading Scheme) at point of production, a hydrogen user may not need to know the carbon intensity of the hydrogen. Although carbon taxes and emissions trading schemes exist in a number of jurisdictions, their application is far from universal, with governments' relying on a mix of policy instruments to encourage decarbonisation. Where this is focussed on users, for example requiring a sector such as transport to reduce its GHG intensity, then users will need to be able to demonstrate how much the hydrogen they are using reduces emissions or ensure the hydrogen they buy meets government standards. The same applies to hydrogen derivatives such as ammonia, methanol or synthetic fuels (hydrocarbons). As well as the additional emissions from the production and transport of the derivatives, the source of carbon used in methanol and synthetic fuels will determine the overall GHG intensity of the derivative.²⁷

The common thread is that governments, producers, users and importers all need to know the carbon intensity of hydrogen, as well as its cost. If there is an agreed methodology for measuring the intensity it enables governments and users to compare the carbon intensity of different producers and then make an informed choice of which source of hydrogen to use. It is therefore important to understand how to measure hydrogen's carbon intensity.

3. Clarifying the nomenclature

As might be expected in nascent market, there is as yet no agreed and internationally recognised nomenclature for low carbon hydrogen. Rather, policy makers and market participants follow the Humpty Dumpty approach to terminology,²⁸ whereby the meaning of the words used depends on who is using them.

²⁷ This is covered in the EU [Delegated Act establishing a minimum threshold for greenhouse gas \(GHG\) emissions savings of recycled carbon fuels](#).

²⁸ " 'When I use a word,' Humpty Dumpty said in rather a scornful tone, 'it means just what I choose it to mean — neither more nor less.' 'The question is,' said Alice, 'whether you can make words mean so many different things.' 'The question is,' said Humpty Dumpty, 'which is to be master — that's all.' " Lewis Carroll, *Through the Looking Glass*.

3.1 The colour of hydrogen.

Initially much of the discussion on hydrogen definitions focused on the production method, with the following broad categories:

- Black hydrogen – based on gasification of black coal without carbon capture and storage (CCS)
- Brown hydrogen - based on gasification of brown coal / lignite without CCS
- Grey hydrogen - based on methane reforming without (CCS)
- Green hydrogen - based on electrolysis using renewable electricity
- Blue hydrogen - based on methane reforming combined with carbon capture and storage
- Pink hydrogen - based on electrolysis using nuclear electricity
- Turquoise hydrogen - based on pyrolysis of methane
- White hydrogen - naturally occurring hydrogen found in geological deposits

3.2 Clean, renewable or low carbon hydrogen

An alternative approach is the use of terms such as ‘clean’, ‘renewable’, or ‘low carbon.’ Such terms are used in the legislation in different jurisdictions to support the development of low carbon hydrogen. However, the terms are jurisdiction specific. They have different carbon intensity thresholds, different means of measuring the carbon intensity of hydrogen, and include different production pathways. The definitions for US ‘clean’ hydrogen, EU ‘renewable’ hydrogen based on RFNBOs, and EU and UK ‘low carbon’ hydrogen can all include hydrogen based on nuclear or renewable electricity.

These different requirements are illustrated in the Table 2 below. Explanation of the different criteria are discussed later in the paper.

Table 2: Comparison of different hydrogen definitions

Criteria	EU Renewable Fuels of Non-Biological Origin (RFNBO) ²⁹	EU Low Carbon Hydrogen ³⁰	UK Low Carbon Hydrogen ³¹	US Clean Hydrogen Production Standard ³²
Carbon intensity limit	28.2 gCO ₂ e/MJ 3.4 kgCO ₂ e/kgH ₂	28.2 gCO ₂ e/MJ 3.4 kgCO ₂ e/kgH ₂	20.0 gCO ₂ e/MJ 2.4 kgCO ₂ e/kgH ₂	33.4 gCO ₂ e/MJ 4.0 kgCO ₂ e/kgH ₂
System boundary	Well to wheel	Well to wheel	Well to production gate	Well to production gate
Scope Emissions included in carbon intensity calculation	Scope1, Scope 2, partial Scope 3 (upstream and downstream emissions)	tbc	Scope1, Scope 2, partial Scope 3 (upstream emissions only.)	Scope1, Scope 2, partial Scope 3 (upstream emissions only.)

²⁹ Based on [EU Delegated regulation for a minimum threshold for GHG savings of recycled carbon fuels and annex](#) and [EU Delegated regulation on Union methodology for RFNBOs](#).

³⁰ Based on low carbon hydrogen definition in [DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal markets for renewable gas, natural gas and hydrogen](#) and [EU Delegated regulation for a minimum threshold for GHG savings of recycled carbon fuels and annex](#). Note that details on the low carbon hydrogen definition will be decided in a future delegated act.

³¹ Based on [UK Low Carbon Hydrogen Standard Version 3, December 2023](#).

³² Based on U.S. Department of the Treasury Proposed 45V tax credit rules. [Federal Register/Vol. 88, No. 246/Tuesday, December 26, 2023/Proposed Rules](#).



Production method	Non biomass based e.g. electrolysis based on renewable electricity	Non-renewable based e.g. electrolysis using nuclear electricity, fossil fuel based with CCS	Electrolysis Fossil gas reforming with CCS Biogenic gas reforming Biomass gasification Waste (biogenic, fossil or mixed) gasification Gas splitting producing solid carbon	SMR or ATR with CCS Coal gasification with CCS Biomass gasification with CCS Electrolysis
Proof of connection to electricity	Direct connection or PPA or connected to grid where 90% of electricity is renewable in past year or grid has carbon footprint of less than 18g CO ₂ e/MJ	tbc	Direct connection or PPA or grid connection	Energy Attribution Certificates allowed
Temporal Correlation	Monthly until 31 st December 2029 and hourly from 1 st January or if the grid electricity price is equal to or lower than €20/MWh or lower than 36% of the EU ETS price	tbc	Half hourly	Annual until 31 st December 2028, hourly thereafter.
Electricity Additionality	Yes. Renewable generation must have come into operation no more than 36 months before the electrolyzers unless grid is already > 90% renewable or has a carbon footprint of less than 18gCO ₂ e/MJ.	tbc	No	Yes. Electricity generation must have come into operation no more than 36 months before the electrolyser
Geographic correlation	In same grid zone or neighbouring grid zone if price in neighbouring grid zone is lower than zone	tbc	N/A as GB has single electricity grid	Yes – EAC must refer to generation in the same region as the hydrogen production



Definitions based on colour or broad terms such as ‘clean’ or renewable make for a useful journalistic shorthand, but are inadequate from a government, producer or user perspective. Such broad terms do not give any indication of the carbon intensity of the hydrogen, which is the key metric from a decarbonisation perspective. Even if one knows the carbon intensity metric for each jurisdiction, the different measurement criteria mean that it is not possible to compare either the cost of the hydrogen (\$/kgH₂) on a like for like basis, or the relative cost of emissions avoided for hydrogen (\$/tCO₂abated/kgH₂). Whilst the EU definition includes the emissions associated with transport and storage of low carbon hydrogen, the UK and US definitions do not. This means that the latter two are not capable of comparing the relative cost of emissions avoided for domestically produced low carbon hydrogen with those of imports. (It should be noted that, unlike the EU, the UK and US frameworks are designed to support domestic production and use only and therefore do not consider trade aspects. The EU explicitly expects to import low carbon hydrogen.)

Lack of a common nomenclature creates confusion which inhibits market development. This is perhaps best illustrated by a footnote to the recent COP 28 Declaration of Intent on Clean Hydrogen:

“Based on language in its national legislation, the United States uses the term “clean hydrogen” rather than “low-carbon hydrogen,” and understands “low-carbon” in this document and others as inclusive of hydrogen produced with renewable energy, nuclear energy, or carbon capture and sequestration, but not inclusive of hydrogen produced with unabated fossil energy including natural gas.”³³

4. Measuring hydrogen’s carbon intensity

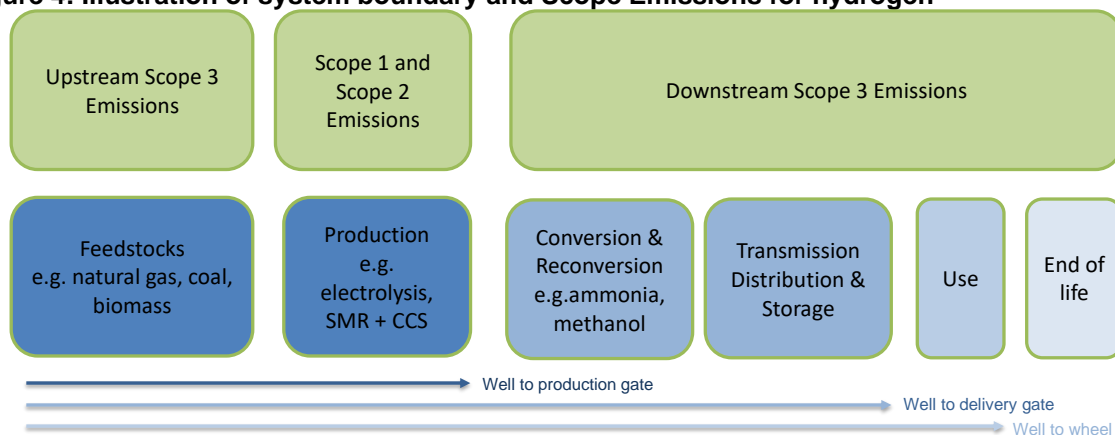
There are two steps to determining hydrogen’s carbon intensity. The first is which emissions in the value chain to include in the calculation. The second step is how to calculate the values of the different sources of emissions i.e. the emissions calculation methodology.

4.1 System Boundary and Scope Emissions.

The decision on which emissions to include is partly determined by the system boundary – emissions within the system boundary are included in the calculation, whilst those outside it are not. A related concept is that of Scope Emissions which differentiates emissions according to whether they are a direct or indirect result of a company’s activities.

The system boundary for hydrogen production and the different Scope Emissions can be illustrated as follows (see Figure 4).

Figure 4: Illustration of system boundary and Scope Emissions for hydrogen



Source: Adapted from [UK Low Carbon Hydrogen Standard](#).

³³ COP28 Declaration of Intent On Mutual Recognition Of Certification Schemes For Renewable And Low-carbon Hydrogen And Hydrogen Derivatives COP 28 UAE. 6th December 2023.



The blue boxes illustrate the different processes involved in hydrogen production:

- Production of feedstocks required e.g. natural gas or biogas for methane reforming.
- The hydrogen production process e.g. electrolysis, methane reforming.
- Conversion of the hydrogen into hydrogen carriers (e.g. Liquid Organic Hydrogen Carriers) or derivatives (e.g. ammonia) for the purposes of transport, and if required reconversion back into hydrogen.
- Transmission, distribution and storage of hydrogen, for example in pipelines or pressurised containers, to the point of use.
- End use of the hydrogen for example in boilers or fuel cells.
- End of life disposal of equipment.

The different system boundaries are often described using terms such as ‘well to gate’ or ‘well to wheel.’

- ‘Well to factory gate’ includes emissions derived from the production and transport of inputs used in the production process (e.g. generation of electricity or production of natural gas) and emissions from the production process itself up to the point where the hydrogen is ready to be transported from the ‘factory gate’ to end users. Emissions associated with the production and transport of inputs are sometimes referred to as ‘upstream’ emissions.
- ‘Well to customer gate’ may include emissions resulting from the transportation of hydrogen, including any conversion and reconversion to and from hydrogen carriers to the customer if the ‘gate’ in question is the customer’s factory gate i.e. the point where the hydrogen is delivered to the customer.
- ‘Well to wheel’ includes the same emissions as ‘well to gate’ but adds in emissions from the transportation (including any conversion and reconversion to and from hydrogen carriers) and then use of the hydrogen or hydrogen derivatives. Emissions produced between the ‘gate’ and the ‘wheel’ are sometimes referred to as ‘downstream’ of the production process.

The above approach can be adjusted for hydrogen derivatives such as methanol, ammonia or synthetic fuels which are then used in their own right rather than as a means to transport hydrogen. Some derivatives would have emissions associated with their end use. In the case of both methanol (CH_3OH) and synthetic fuels such as synthetic aviation fuel ($\text{C}_{11}\text{H}_{22}$), e-methane (CH_4) or synthetic diesel ($\text{C}_{12}\text{H}_{23}$) there would be CO_2 emissions at the point of use, unlike hydrogen (H_2) or ammonia (NH_3). In this case the carbon intensity of the hydrogen derivative would depend on the source of the carbon used in their production. Fossil fuel-based CO_2 captured using CCS would have a high carbon intensity because its use would simply be delaying the release of the CO_2 into the atmosphere. If the use of the derivatives included CCS at the point of use, then the carbon intensity would be lower depending on the efficiency of the CCS process, as this would form a ‘closed loop’ for the CO_2 emissions. Carbon sourced from DAC or BECCS would also have a lower carbon intensity as the CO_2 emitted from combustion of the derivative would have already been captured from the atmosphere.

Scope Emissions are based on the Greenhouse Gas Protocol Corporate Accounting and Reporting Standard³⁴ and are classed as follows:

- Scope 1 emissions: A production pathway’s direct GHG emissions
- Scope 2 emissions: GHG emissions associated with the generation of electricity outside of the hydrogen production facility, heating/cooling, or steam purchased for own consumption.
- Scope 3 emissions: A production pathway’s indirect GHG emissions other than those covered in scope 2. This can include emissions from the upstream production of natural gas, manufacturing of equipment used in the production or transportation of hydrogen or emissions

³⁴ [GHG Protocol Corporate Accounting and Reporting Standard Revised Edition March 2004. Chapter 4.](#)



from the use of the hydrogen and its emissions. Scope 3 emissions are the Scope 1 or 2 emissions of other companies.

Countries have taken different approaches to setting the system boundary and also which Scope Emissions to include. For example, the US and UK use a 'well to production gate' approach whilst the EU uses a 'well to wheel' approach. The UK, EU and US include upstream Scope 1 and Scope 2 emissions but only the EU includes downstream Scope 3 emissions. None of them include Scope 3 emissions resulting from the manufacture of equipment used in the production of hydrogen.

4.2 Emissions calculation methodology

For each stage in the system boundary, and for different hydrogen production processes, the emissions calculation methodology sets the rules for how the overall carbon intensity of the hydrogen is calculated. The aim is to have a standardised approach to ensure comparability of different hydrogen production and use pathways. Examples of methodologies include:

- The two EU delegated acts governing RFNBOs.³⁵
- The UK Low Carbon Hydrogen Standard.
- The IPHE Methodology for Determining the Greenhouse Gas Emissions Associated with the Production of Hydrogen.³⁶
- The US Hydrogen GREET model³⁷

Just as different financial accounting approaches can lead to different results (e.g. impact of treatment of depreciation on profit and loss), different methodologies may lead to different results for the carbon intensity of hydrogen. However, there are some common themes which are explored below.

4.3 Measuring upstream emissions

Upstream emissions will include the production of any feedstocks (e.g. oil, natural gas, biomass including biogas, coal) and its processing and transportation to the hydrogen production plant. As well as the direct CO₂ emissions from energy used in the production process, there may be fugitive methane emissions resulting from the production of oil, natural gas, biogas or coal, or from the transportation of natural gas or biogas / biomethane. Natural gas transported as LNG will generally have a higher carbon intensity than natural gas transported via pipeline because of the higher energy requirements of liquefaction, transportation and regasification. The distance and method of coal transportation will also impact its carbon intensity. For shipping, whether of coal or LNG, the type of fuel used in shipping and the efficiency of the ship's engines, as well as the shipping distance, will impact the calculation. Thus, upstream emissions will depend on the type of feedstock, the method and efficiency of production, and the distance, method and efficiency of transportation to the hydrogen production plant. The carbon intensity of feedstocks is likely to be very source specific.

The IEA has calculated the impact of upstream emissions (including both production and transportation of the natural gas³⁸) for natural gas reforming as 2.4 kgCO_{2e}/kg_{H₂} based on a median upstream emissions value of 15kgCO_{2e}/GJ_{NG}. However, the range of upstream emissions is between 4.5 kgCO_{2e}/GJ_{NG} and 28 kgCO_{2e}/GJ_{NG} which implies a range of 0.7 kgCO_{2e}/kg_{H₂} and 4.5 kgCO_{2e}/kg_{H₂}. For coal gasification the IEA estimates that 20% of emissions are related to the production and transportation of coal to the hydrogen production plant which vary between 6 and 23 kgCO_{2e}/GJ_{COAL}.³⁹

³⁵ [EU Delegated regulation for a minimum threshold for GHG savings of recycled carbon fuels and annex and EU Delegated regulation on Union methodology for RFNBOs.](#)

³⁶ <https://www.iphe.net/iphe-wp-methodology-doc-jul-2023>

³⁷ https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf

³⁸ In the IEA's terminology these are upstream (production) and midstream (processing and transportation) emissions for natural gas, but these count as upstream emissions from a hydrogen value chain perspective.

³⁹ IEA (2023), [Global Hydrogen Review 2023](#), IEA, Paris, Licence: CC BY 4.0. Pages 88 to 89.

The challenge for governments, producers and users is whether the upstream emissions are measured, and the reliability of the measurements. Where source specific measurements are not available, governments may use default emission factors which is the approach taken by the UK, EU and US for upstream natural gas emissions.

4.4 Measuring hydrogen production emissions

Emissions from hydrogen production will be determined by the production process used and the energy used in that process. Different forms of electrolysis have different efficiency rates (i.e. how many kWh of electricity are required to produce a kWh of hydrogen) as well as different energy requirements to make the process work (e.g. high temperature electrolysis versus low temperature electrolysis). Where the production process relies on CCS, the rate of capture of the CCS process will also be important. For example, SMR + CCS has a lower capture rate compared to ATR + CCS, as well as requiring more energy to produce a given quantity of hydrogen. However, ATR + CCS has a higher capex cost.⁴⁰ Hydrogen may also be produced as a by-product of industrial processes such as the Chlor Alkali process. Therefore, it is necessary to decide how to attribute the emissions from the process to the chlorine, caustic soda and hydrogen produced.

Methane reforming technologies are mature, as they have been in use for many years for producing high carbon hydrogen, and therefore are unlikely to become significantly cheaper or more efficient. By contrast electrolyzers are expected to improve significantly as a result of 'learning effects' as the technology is deployed more widely, and economies of scale in both the electrolyser production process and the size of the electrolysers themselves. Other technologies such as pyrolysis may also become more competitive. The carbon intensity cost benefit analysis for different types of hydrogen production is therefore likely to change over time.

5. Measuring the carbon intensity of electricity used in electrolysis.

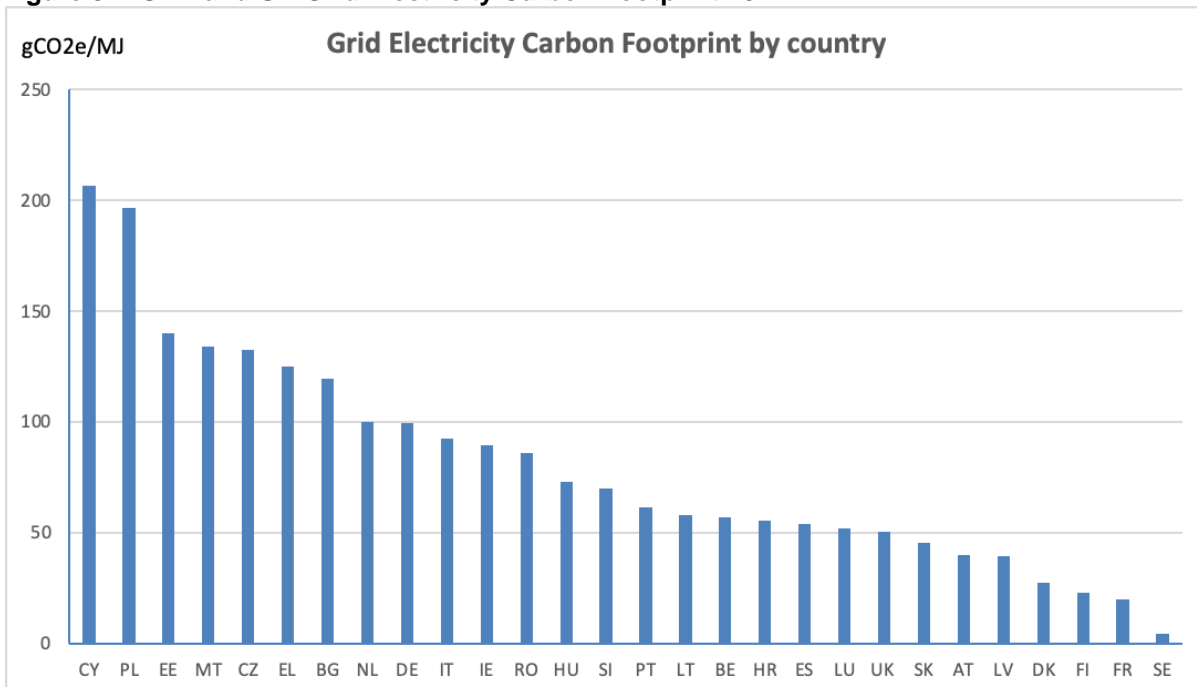
For electrolytic hydrogen the key determinant of hydrogen's carbon intensity is the carbon intensity of the electricity used. Electricity from renewables (e.g. hydro, wind, solar, biomass) or nuclear will have zero emissions. However, wind and solar are intermittent, and have lower potential availability than other generation, depending on the number of hours that the wind or sun are available in the generator's location. Hydro or nuclear which are both dispatchable (i.e. can be called on as required within their technical limits) and their availability depends on more predictable factors such as reservoir levels or fuel availability. Even so nuclear generation is not considered as flexible as gas fired turbines, and hydro can be affected by low reservoir levels caused by droughts.

The availability and dispatchability of zero carbon electricity affects the economics of electrolysers because of the high capex costs of electrolysers. A lower availability of zero carbon electricity leads to a lower load factor for the electrolyser, and hence a higher Levelised Cost of Hydrogen (LCOH) for the hydrogen produced. This may be offset by a lower electricity price when there is plenty of wind and solar available, as this is often associated with low electricity prices due to the low marginal costs of wind and solar generation. However, if electrolysers take electricity from the grid in order to boost the electrolyser load factor, the carbon intensity of the hydrogen produced will be determined by the carbon intensity of electricity supplied to the grid. Most countries do not yet have generation mixes which are fully zero carbon (via a mix of renewables and nuclear), and therefore their carbon intensity varies considerably. Figure 5 below illustrates the different carbon intensities of electricity grids in the EU 27 and the UK.

⁴⁰ Source: UK Department for Business Energy & Industrial Strategy. [Hydrogen Production Costs 2021 Annex.](#)



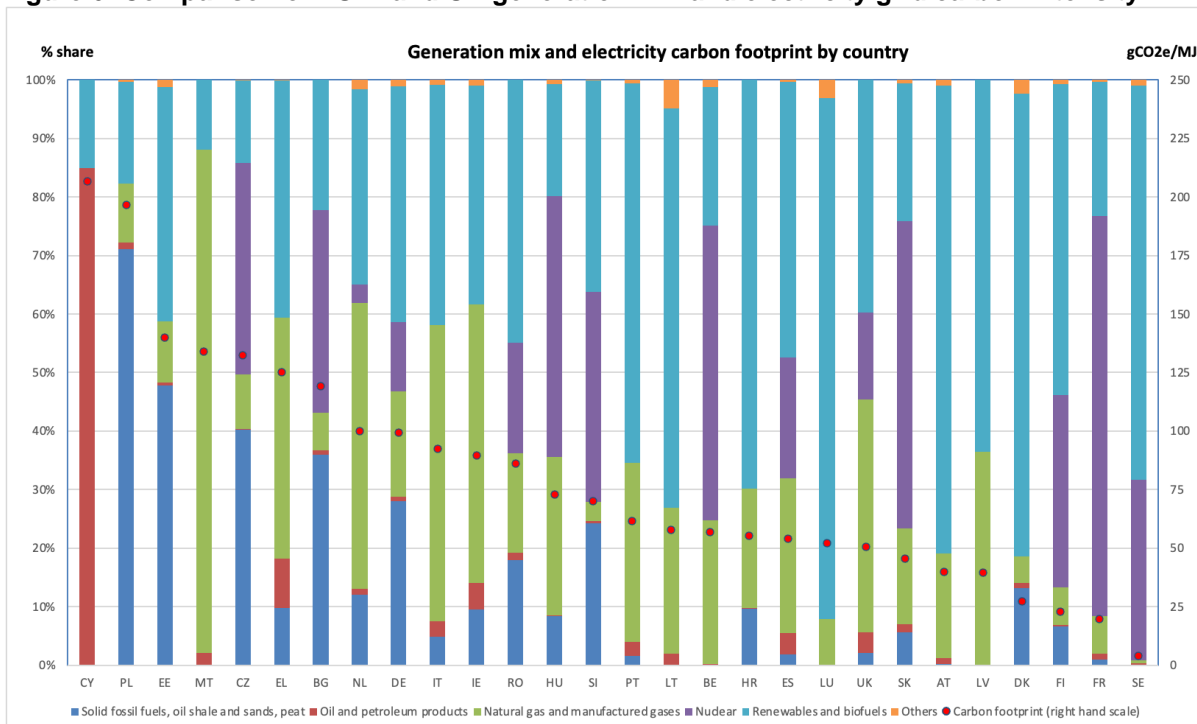
Figure 5: EU 27 and UK Grid Electricity Carbon Footprint 2021



Source: : EU Energy Statistical Pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics

Note that these are the carbon intensities for electricity generated during a year. The carbon intensity during any shorter period, such as a month, day or hour, will be different depending on the generation available at that point in time. The generation mix also varies widely between country. Figure 6 below shows compares the annual generation mix of the EU 27 + UK with the carbon intensity.

Figure 6: Comparison of EU27 and UK generation mix and electricity grid carbon intensity



Source: EU Energy Statistical Pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics

This shows how it is not just the share of zero carbon electricity in the mix which is important in determining the carbon intensity of grid electricity but also what makes up the rest of the electricity mix. For example, the UK and Germany (DE) have a very similar share of zero carbon electricity (nuclear and renewables) but the greater share of coal in the German mix means it has a significantly higher overall electricity carbon intensity. Italy (IT) has a lower zero carbon electricity share than Germany but uses a lot less coal than Germany and therefore has a slightly lower carbon intensity. Czechia (CZ) has a much higher share of zero carbon electricity than the Netherlands (NL) but because Czechia uses a lot of coal rather than natural gas as in the Netherlands, Czechia's electricity has a considerably higher carbon intensity.

It is easy to measure the carbon intensity of hydrogen where electrolyzers are only directly connected to their generation source as it is easy to correlate the electricity used with the hydrogen produced. The picture becomes more complex if electrolyzers are connected to the grid, either as well as a direct connection to their main generation source or if they are relying solely on the grid to provide the electricity. This is because of the way electricity grids work, and the generation mix associated with different grids.

Electricity has to be balanced in real time i.e. the amount of electricity generated and supplied to the grid must equal the amount taken from the grid at any given moment to maintain system stability. As demand for electricity rises and falls during the day, grid operators will call on or stand down different generators to ensure that supply and demand balance. An alternative is to incentivise demand to increase or decrease so that supply and demand can balance. Either way, the carbon intensity electricity supplied to the grid will depend on the generators which supply the grid at that point in time. The carbon intensity of the grid can vary considerably over any given period of time depending on the generation available.

There is growing interest in electricity storage to store electricity produced when prices are low and use it when prices are high. Examples include the large-scale utility battery provided by Tesla in Victoria,⁴¹ Australia or pumped hydro.⁴² The carbon intensity of the stored electricity will depend on the carbon intensity of the electricity used at the time of storage.

Adding new sources of demand for electricity such as electrolyzers may impact the generation mix. For example, a new electrolyser connecting to the grid will increase demand for electricity generation. If this additional generation is supplied by fossil fuel generation, the carbon intensity of the grid will increase. Even if the electrolyser contracts with an existing renewable generator, which is already supplying the grid, the effect is the same if the demand which has been displaced by the electrolyser is met via fossil fuel generation. Only if the additional demand on the grid is met by additional zero carbon generation will a higher grid electricity carbon intensity be avoided. Otherwise, the effect is that the electrolyser is 'robbing Peter to pay Paul' in terms of zero carbon electricity. That is, hydrogen can show it has a low carbon intensity based in zero carbon electricity only at the expense of increasing the carbon intensity of electricity used by others.

The generation mix can give an indication as to how additional electricity demand will be supplied but many factors will determine the actual outcome, for example generation availability and the relative costs of fuels (e.g. coal vs. gas) as well as the prevailing carbon price if one is applied to generation (e.g. the EU and UK Emissions Trading Systems). If the growth of overall electricity demand (including but not only electrolyser demand) is more than the growth in zero carbon electricity generation, the additional generation required will cause the grid to have a higher carbon intensity that would otherwise be the case.

The case for electrolytic hydrogen is often based on its ability to use 'surplus' renewable electricity which would otherwise be curtailed because there is insufficient demand. In a market-based system an excess of electricity generation over demand will lead to very low or even negative prices, which should increase

⁴¹ [Victorian Big Battery](#) – a 300MW / 450 MWh battery consisting of 210 Tesla Megapacks.

⁴² For example the [Coire Glas pumped hydro project](#) in Scotland which will be the first new pumped hydro project in the UK for 40 years with a potential capacity of up to 1500 MW and energy storage of 30 GWh.

demand. However, if the increase in demand is insufficient to match supply, then generation will need to be curtailed. The grid operator will have stood down dispatchable generation (e.g. fossil fuel based) first, but there may still be an excess of wind or solar generation which has to be curtailed. Hydrogen can act as a form of renewable energy storage whereby the excess renewable generation can be converted to hydrogen which is stored. However, this requires that the electrolyser be located in the same grid zone as the curtailed generation. Had there been sufficient interconnection with a neighbouring grid zone, the excess generation in the first grid zone would have been exported to the neighbouring grid until either there was insufficient generation to meet demand and additional electricity generation was despatched, or there was still excess generation which would be curtailed.

5.1 Temporal correlation, additionality and geographic correlation

The above issues have led to considerable discussion over requirements for 'temporal correlation' and 'additionality' and 'geographic correlation' or 'deliverability.' The first is the requirement that the carbon intensity for hydrogen be measured based on the electricity used in a given time period (e.g. half hour, hour, month, year). The second is that hydrogen projects be able to demonstrate that any zero-carbon electricity they use is from a new source ('additional') to avoid the 'robbing Peter to pay Paul' effect. The third is that the electrolyser be in the same grid zone as the generation or that the electrolyser is capable of receiving the electricity generated i.e. there must not be transmission constraints between the generator and the electrolyser.

5.2 Comparing hourly and monthly temporal correlation

In the case of temporal correlation, the time period used is important. A shorter time period will more accurately reflect the requirement that electricity grids balance in real time, and that the carbon intensity of hydrogen is based on the carbon intensity of the electricity generated and used at the time of hydrogen production. A short time period means that electrolyser utilisation will need to match the availability of zero carbon generation or take electricity from the grid. However, grid electricity may have a high carbon intensity which in turn will increase the carbon intensity of the hydrogen, depending on the share of grid electricity in the production of hydrogen for a given time period. A longer time period makes it easier for electrolysers to 'average out' the intermittency of renewable generation, and thereby achieve a higher load factor.

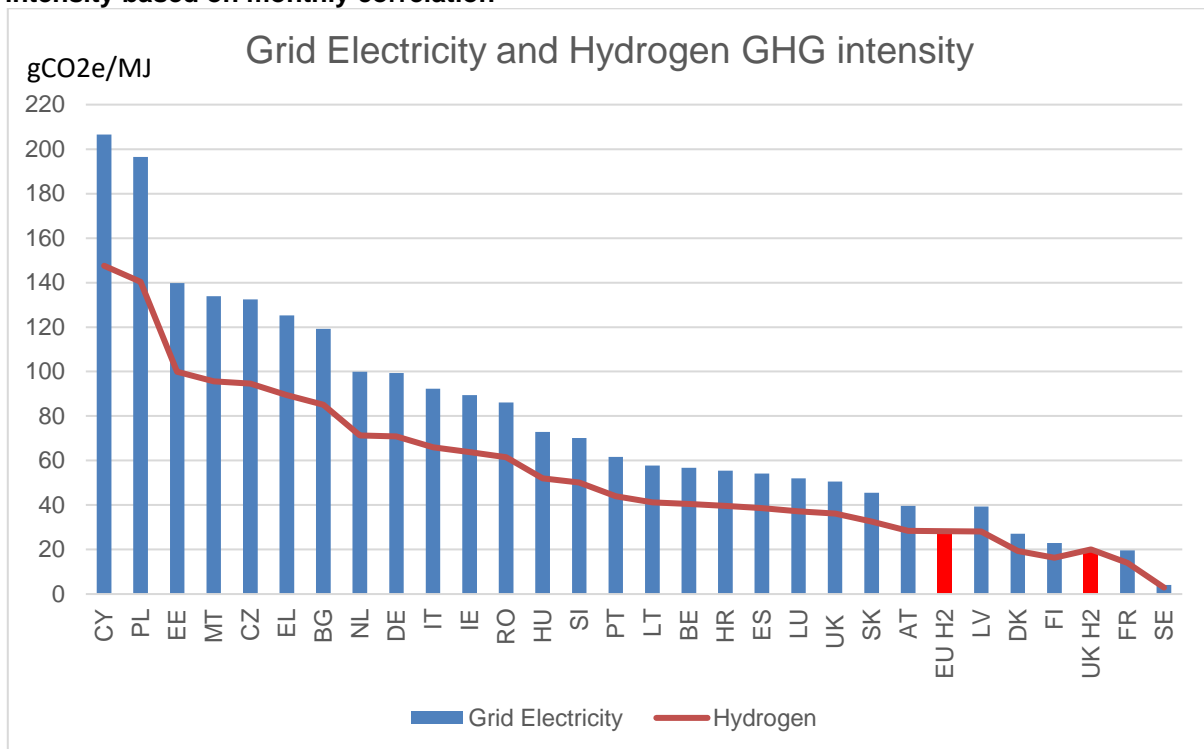
When the EU Commission was consulting on its proposed rules for electrolytic hydrogen using renewable electricity,⁴³ many respondents argued that temporal correlation rules based on a short time period would mean that hydrogen would be higher cost because of the low load factors of renewable generation and hence low utilisation of the electrolysers. As a compromise the EU rules allow a longer temporal correlation period of one month until 2030 – so long as the electricity used by the electrolyser in that month matches that generated by renewable sources in the same month, all the electricity used by the electrolyser would count as renewable and hence have zero emissions.

To illustrate the effect this has, imagine a case where the renewable generation is a solar farm with capacity of 2 MW and the sun shines reliably for 12 hours a day. Based on a 31-day month this would produce 744 MWh of electricity. Using monthly correlation an electrolyser could run 24 hours a day for 31 days so long as it was using only 1 MW of electricity per hour, and still use the same amount of renewable electricity as that generated. However, for 12 hours a day the electrolyser would be using electricity from the grid when the sun was not shining. Of the 744 MWh consumed by the electrolyser, 372 MWh would be grid electricity and 372 MWh renewable. The carbon intensity of the hydrogen produced would vary depending on the carbon intensity of the grid electricity generated at the time of production, which in turn would depend on the generation units on the system at that time. However, the impact can be illustrated more simply if one assumes that the grid electricity carbon intensity is the annual average carbon intensity.

⁴³ <https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/7046068-Production-of-renewable-transport-fuels-share-of-renewable-electricity-requirements- en>



Figure 7: Comparison of EU27 and UK 2021 grid electricity and electrolytic hydrogen carbon intensity based on monthly correlation



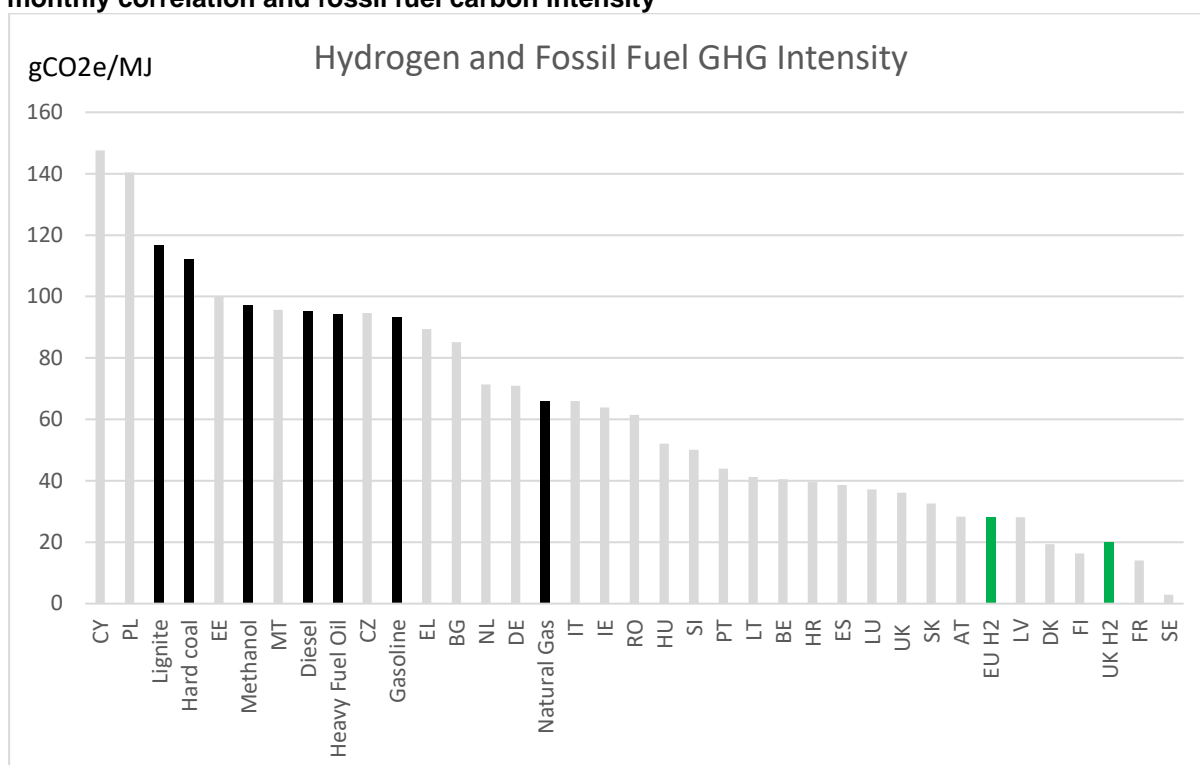
Source: Author's calculations, EU energy statistical pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics.

Figure 7 compares the carbon intensity of electricity for the EU 27 and the UK (blue bars), and the hydrogen carbon intensity thresholds of the EU and UK (red bars).⁴⁴ It then shows that carbon intensity of hydrogen produced using 50% renewable electricity and 50% grid electricity, as in the example above, but applying the average carbon intensity of grid electricity instead of treating it as zero emissions under the EU monthly temporal correlation rules. As can be seen very few countries would meet the EU hydrogen standard if the carbon intensity of grid electricity is included.

The impact of the different grid carbon intensities on the ability of any hydrogen to help decarbonise the economy can be shown by comparing the hydrogen carbon intensities shown in Figure 7 above, with those of fossil fuels (Figure 8).

⁴⁴ Note the comparison of the UK and EU carbon intensity thresholds is not exact because of different system boundaries.

Figure 8: Comparison of EU27 and UK 2021 electrolytic hydrogen carbon intensity based on monthly correlation and fossil fuel carbon intensity



Source: Author’s calculation, EU energy statistical pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics, EU delegated act on GHG savings.

Whilst hydrogen produced in countries with low carbon intensity grids can represent considerable carbon savings compared to fossil fuels, in a significant number of countries the savings are minimal or negative. For example, hydrogen produced in Sweden has a carbon intensity 96% less than natural gas, and in France it is 79% less. However, hydrogen produced in Germany would have a carbon intensity 7% greater than that of natural gas, whilst hydrogen produced using grid electricity in Poland would have a carbon intensity more than double that of natural gas.

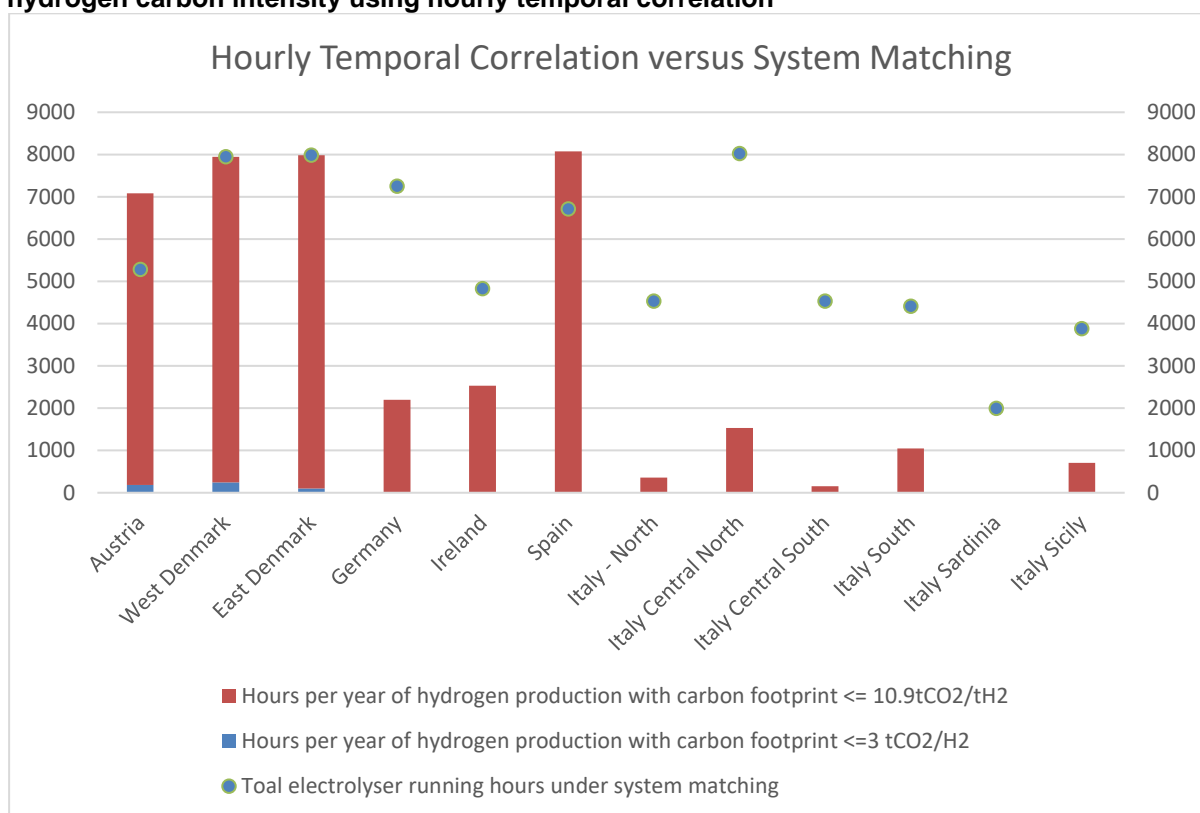
5.3 Comparing hourly correlation with average system matching.

Using approaches other than strict temporal correlation can result in higher electrolyser utilisation at the expense of higher hydrogen carbon intensity. A 2021 study by Bellona⁴⁵ looked at the application of a system level matching whereby electricity generation is counted as renewable if share of renewable generation is higher than the average share for the grid based two years prior to the year in question (Figure 9). Thus, if the average share for renewable generation was 10% in Year X, so long as renewable generation during a given period in Year X+2 was above 10%, the all the electricity used in electrolysis would be counted as renewable even though most of it could be fossil fuel based. The analysis looked at how many hours an electrolyser could run under the system matching rules, and how many of those hours would have met a carbon intensity of ≤ 3 tCO₂/H₂ (the EU Taxonomy standard⁴⁶) or ≤ 10.9 tCO₂/H₂ (the equivalent of methane reforming of natural gas without CCS). The analysis was based on hourly generation and demand for 2020 for 6 EU Member States – Austria, Denmark, Germany, Ireland, Spain and Italy. Both Denmark and Italy have more than one grid zone, so the study looks at the results for each sub-national grid.

⁴⁵ Bellona (2021) ‘Cannibalising the Energiewende? 27 Shades of Green Hydrogen.’

⁴⁶ [EU taxonomy for sustainable activities](#). The EU taxonomy allows financial and non-financial companies to share a common definition of economic activities that can be considered environmentally sustainable and includes different screening criteria for environmental objectives for different activities including hydrogen production.

Figure 9: Comparison of carbon electrolyser running hours under system matching and hydrogen carbon intensity using hourly temporal correlation



Source: Adapted from Bellona (2021) 'Cannibalising the Energiewende? 27 Shades of Green Hydrogen' and Bellona (2021) 'Impact Assessment of RED II Delegated Act on Electrolytic Hydrogen CO₂ Intensity. Technical Annex: Countries Data Deep Dive.'

Using grid electricity only a few hours of electrolytic production is possible when hourly correlation is used if the EU Taxonomy standard is to be met: 181 hours in Austria, 243 hours in West Denmark and 101 hours in East Denmark (blue bars). Hydrogen produced using grid electricity could still match or beat the emissions from hydrogen produced using methane reforming without CCS when applying hourly correlation (orange bars). The 'cleaner' the grid the more hours when this can be achieved. However, the system matching approach enables hydrogen producers to claim many more hours when their hydrogen meets the EU Taxonomy Standard (blue dots). In all countries the number of hours allowed under System Matching exceeds the actual hours when the Taxonomy Standard is met. In Germany, Ireland and Italy the number of hours also exceeds the hours when hydrogen has the same or lower carbon intensity as methane reforming without CCS – which means for many hours hydrogen would be produced with higher emissions than if methane reforming is used.

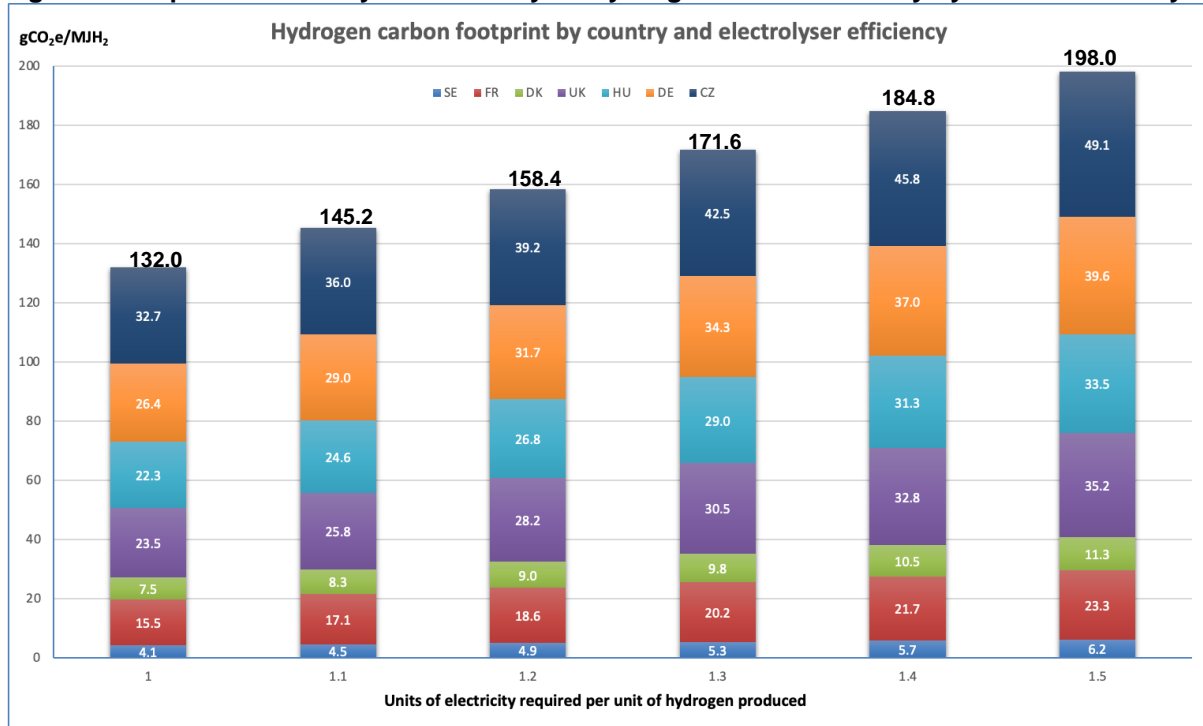
5.4 Interaction of electrolyser efficiency with temporal correlation

The efficiency of the electrolyser also has an impact on the unit cost and carbon intensity of the hydrogen produced. A higher efficiency will reduce unit costs, as it uses less electricity to produce a unit of hydrogen. It will also have a beneficial effect on the carbon intensity of hydrogen because of the gearing effect that electrolyser efficiency has on the hydrogen carbon intensity. For an electrolyser which requires 1.4 MJ of electricity to produce 1 MJ of hydrogen, the carbon intensity of the hydrogen will be 1.4 times that of electricity in terms of gCO₂e/MJ. For a given carbon intensity of electricity the carbon intensity of hydrogen produced will be 17% higher than that of hydrogen produced by a more efficient electrolyser which requires only 1.2 MJ of electricity to produce 1 MJ of hydrogen. However, the gearing effect also means that the amount of additional carbon emitted is considerably more in a country where the electricity used has a higher carbon intensity compared to a country with a lower carbon intensity. Figure 10 below shows the total carbon intensity by country in gCO₂e/MJ and by electrolyser efficiency,



here shown as the MJ of electricity required to produce one MJ of hydrogen. A selection of European countries with a range of electricity carbon intensities was chosen to illustrate the impact of electrolyser efficiency on their hydrogen carbon intensities.

Figure 10: Impact of electrolyser efficiency on hydrogen carbon intensity by selected country



Source: Author's calculations, EU energy statistical pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics.

Table 3 below shows examples of different efficiency levels and electricity required to produce hydrogen.

Table 3: Electrolyser efficiency rates and electricity consumption per unit of hydrogen produced

MJ of Electricity required to produce 1 MJ of hydrogen	Implied Electrolyser Efficiency
1.0	100%
1.1	91%
1.2	83%
1.3	77%
1.4	71%
1.5	67%

Source: [UK Department of Business, Energy and Industrial Strategy \(BEIS\) Hydrogen Production Costs 2021 Annex](#). The Annex gives a range of electrolyser efficiencies for three different technologies – Alkaline, Proton Exchange Membrane (PEM) and Solid Oxide Electrolysis (SOE) – as they are expected to evolve over time. Note that SOE can have an efficiency of 100% in terms of electricity used but also requires heat for the reaction. For simplicity's sake this has not been included separately but the carbon intensity of the heat used would also need to be taken into consideration to calculate the total carbon intensity of the hydrogen produced.

The first column on the left shows the carbon intensity of the electricity and assumes an electrolyser efficiency of 100% i.e. 1 MJ of electricity produces 1 MJ of hydrogen. Alternatively, it can be considered as the baseline comparison for the additional carbon intensity of grid electricity in the selected countries



compared to using zero carbon electricity. The remaining columns show the carbon intensity of hydrogen for different electrolyser efficiencies. The columns are cumulative so that each section shows the additional carbon intensity of each country compared to the country which precedes it in terms of lower carbon intensity.

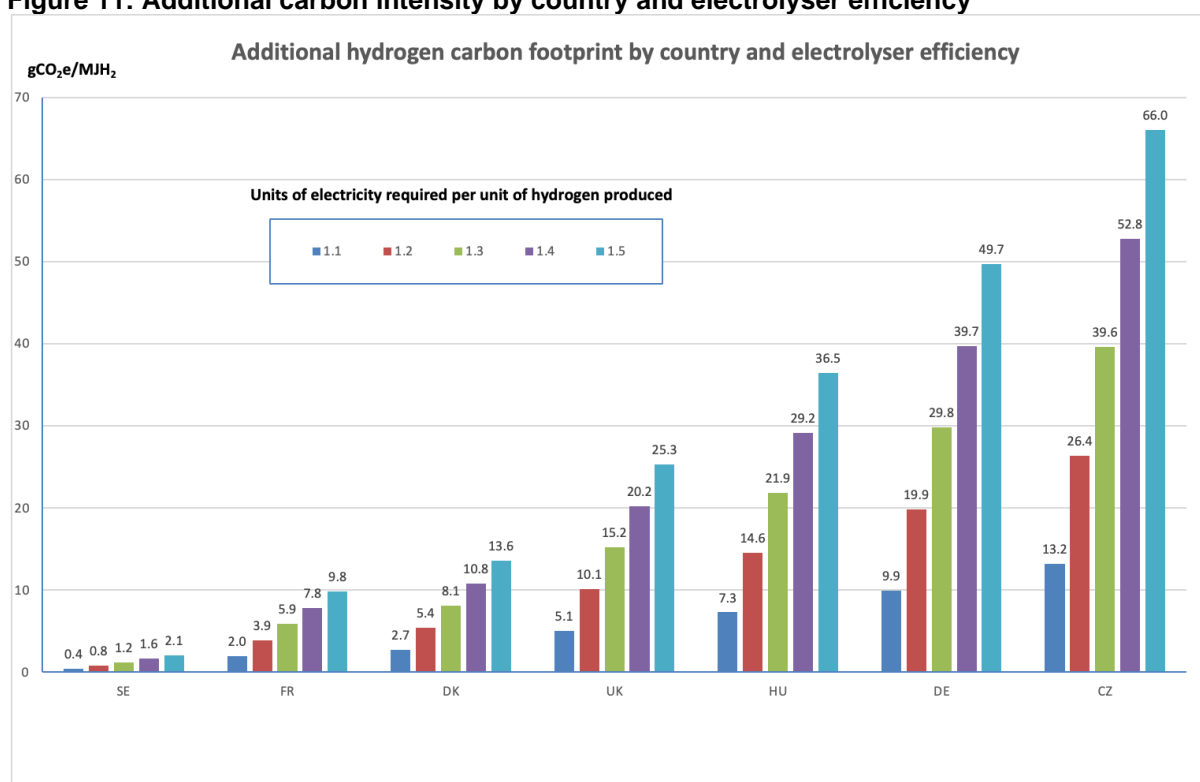
In the first column on the left, Sweden has a very low carbon intensity for its electricity grid of only 4.1 gCO₂e/MJ. France has an electricity carbon intensity of 19.6 gCO₂e/MJ which is 15.5 gCO₂e/MJ higher than Sweden. Denmark has an electricity carbon intensity of 27.1 gCO₂e/MJ which is 7.5 gCO₂e/MJ higher than France and 23.0 gCO₂e/MJ (7.5 + 15.5) higher than Sweden. In this sample Czechia has the highest electricity carbon intensity at 132 gCO₂e/MJ, 32.7 gCO₂e/MJ higher than Germany, and 127.9 gCO₂e/MJ higher than Sweden (32.7 + 26.4 + 22.3 + 23.5 + 7.5 + 15.5).

The remaining columns show the impact of the gearing effect of different electrolyser efficiencies. So, for an electrolyser requiring 1.1 MJ of electricity per MJ of hydrogen produced, Sweden emits 4.5 gCO₂e per MJ of hydrogen, and France emits 17.1 gCO₂e more compared to Sweden. Denmark emits 8.3 gCO₂e more per unit of MJ of hydrogen than France and 25.4 gCO₂e more than Sweden. Czechia emits 145.2 gCO₂e/MJ which is 36.0 gCO₂e/MJ more than Germany and 140.7 gCO₂e/MJ more than Sweden.

For an electrolyser which requires 1.5 MJ of electricity Sweden emits 6.2 gCO₂e per MJ of hydrogen, and France emits 23.3 gCO₂e more than Sweden. Denmark emits 11.3 gCO₂e more per MJ of hydrogen than France and 34.6 gCO₂e more than Sweden. Czechia emits 198.0 gCO₂e/MJ which is 49.1 gCO₂e/MJ more than Germany and 191.8 gCO₂e/MJ more than Sweden.

Another way of looking at the figures is to compare the additional carbon intensity for different electrolysers in the same country (Figure 11).

Figure 11: Additional carbon intensity by country and electrolyser efficiency



Source: Author's calculations, EU energy statistical pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics.

Hydrogen produced using grid electricity in a 1.5 electrolyser in Sweden has a carbon intensity which is 2.1 gCO₂e/MJ more than zero carbon electricity because of the lower than 100% efficiency of the electrolyser. The equivalent figure for France is 9.8 gCO₂e/MJ, 13.6 gCO₂e/MJ for Denmark, 25.3



gCO₂e/MJ for the UK, 36.5 gCO₂e/MJ for Hungary, 49.7 gCO₂e/MJ for Germany and 66.0 gCO₂e/MJ for Czechia.

The amplifying effect of electrolyser efficiency on the underlying carbon intensity of the source electricity is stark. The gap between the most efficient and least efficient electrolyser in terms of additional carbon intensity is only 1.7 gCO₂e/MJ in Sweden (2.1 minus 0.4) but a massive 52.8 gCO₂e/MJ in Czechia (66.0 minus 13.2). Even in a country with a relatively low electricity carbon intensity such as France the difference is 7.8 gCO₂e/MJ, four and a half times that in Sweden. This shows that the impact of hydrogen in terms of reducing GHG emissions depends not only on the efficiency of the electrolysers used, but also on the location of those electrolysers. The least efficient electrolyser in Sweden using grid electricity still has a lower carbon intensity than the most efficient electrolysers using grid electricity in all the other countries except France. The second most efficient electrolyser in Czechia using grid electricity would have a carbon intensity higher than all electrolysers using grid electricity in Sweden, France, Denmark and the UK.

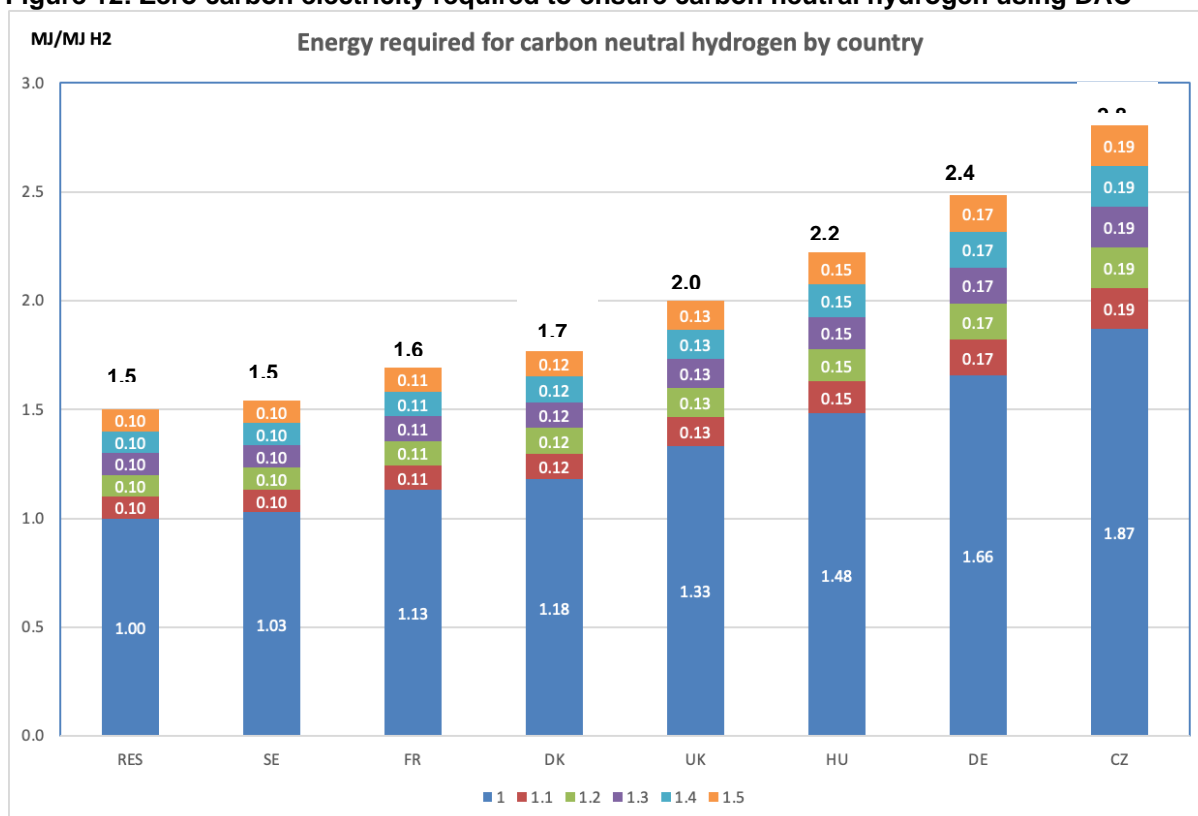
5.5 Impact of looser temporal correlation rules on future renewable energy needs

Another way of looking at the issue is to consider how much zero carbon energy is required to ensure that the hydrogen produced is 'net zero' i.e. there are no emissions associated with its production or any emissions are subsequently captured so that there is no net increase of GHG in the atmosphere. Allowing higher carbon intensity for hydrogen today only makes sense if it allows a faster reduction in emissions tomorrow so that countries remain within the carbon budget. If this does not happen carbon removals will be required. Estimating how much energy is required to ensure that hydrogen production is truly carbon neutral within a 2050 timeframe enables decision makers to understand how much zero carbon zero electricity they may require to stay within the carbon budget.

It is possible to estimate the amount of energy that is required to make hydrogen carbon neutral by calculating the energy required by Direct Air Capture (DAC) combined with permanent storage of the CO₂. DAC takes CO₂ directly from the atmosphere using solid or liquid absorbents but is currently energy intensive. According to the IEA liquid absorbent-based DAC (L-DAC) requires 6.6 GJ of energy to remove 1 tonne of CO₂, whilst solid absorbent based DAC (S-DAC) requires 9.5 GJ of energy to remove 1 tonne of CO₂. Bioenergy with Carbon Capture and Storage (BECCS), which can also create 'negative emissions' if the CO₂ emissions from using biomass is permanently captured, is not considered here because of the complexity of the issues concerning sustainability and availability of biomass. Also BECCS is less than 100% efficient because not all the emissions are captured, so BECCS itself involves some residual emissions.

For the selected countries, the higher the carbon intensity of the grid electricity used and / or the lower the efficiency of the electrolyser, the more CO₂ will need to be captured and hence the higher zero energy requirements per MJ of hydrogen produced. Policy makers can make a choice between investing in the zero-carbon electricity *before* starting hydrogen production to minimise the carbon intensity of hydrogen, or after starting hydrogen production in order to develop the hydrogen supply chain more quickly. The trade-offs involved in such a decision are complex as they involve considerations such as the time it takes to deploy additional zero carbon electricity (e.g. renewables or nuclear), the emissions savings of the hydrogen produced compared to existing fossil fuel use (e.g. using hydrogen in DRI in steel making versus use of coke in blast furnaces), the timing of investment decisions in hydrogen production and use, and likely costs of the different pathways (e.g. currently DAC is very expensive compared to wind and solar electricity generation).

Figure 12: Zero carbon electricity required to ensure carbon neutral hydrogen using DAC



Source Author's calculations, EU energy statistical pocketbook and country datasheets 2023 edition, UK Digest of Energy Statistics, IEA.

Figure 12 shows the energy required for carbon neutral hydrogen by country compared to an electrolyser which uses 100% renewable electricity (RES). For an electrolyser which is 100% efficient (the blue areas of each bar) the RES electrolyser only requires 1 MJ of energy to produce 1 MJ of carbon neutral hydrogen. This represents the base case. Sweden requires 1.03 MJ of energy to produce 1 MJ of carbon neutral hydrogen. Although Sweden has very low carbon intensity electricity, it still emits some CO₂, so 0.03 MJ of energy is required for L-DAC removal of the residual emissions if grid electricity is used to produce the hydrogen. At the other end of the scale a 100% efficient electrolyser in Czechia would require the 1.87 MJ of energy overall as an additional 0.87 MJ of energy would be required to remove the CO₂ emissions associated with the original hydrogen production based on Czech grid electricity. Note this assumes that the additional energy required for DAC compared to the base case is zero carbon energy, otherwise additional energy would be required to make the DAC process itself carbon neutral. The choice is between investing in sufficient zero carbon energy today so that there are no emissions (the RES case) or using grid electricity today and adding additional zero carbon electricity at some point in the future to remove emissions resulting from using grid electricity.

The amount of zero carbon energy required obviously increases as electrolyser efficiency decreases. The additional energy required is represented by the red, green, purple, turquoise and orange areas of each bar. The bold figures above each bar represents the cumulative total. So an electrolyser using 100% renewable electricity but which is only 67% efficient uses 1.5 MJ of energy to produce 1.0 MJ of carbon neutral hydrogen. The same electrolyser in Czechia would ultimately require 2.81 MJ of energy to produce carbon neutral hydrogen – 1.5 MJ of grid electricity and an additional 1.31 MJ of zero carbon energy to remove the CO₂ emissions associated with that grid electricity.

5.6 Comparing hourly, weekly and annual temporal correlation

The impact of additional electricity demand from electrolysers can be illustrated by modelling a system to gauge the impact of adding more electricity demand from electrolysers. As with temporal correlation

the results will very much depend on the grid concerned. A US study⁴⁷ looked at the impact of electrolyser demand on the US Western Interconnection electricity system which comprises 6 zones – Northern California, Southern California, WECC North, New Mexico & Arizona, Pacific Northwest and Wyoming & Colorado. The study looked at impact of additional electrolyser demand through to 2030 under five different scenarios and compared this to the proposed US 45V standard for clean hydrogen:

- No requirements – electrolysis demand uses grid electricity and there are no additional requirements of temporal correlation requirements.
- 100% hourly matching with zero carbon generation i.e. hourly temporal correlation so that electricity used in the hour hydrogen is produced must equal the zero-carbon electricity procured in the same hour.
- 100% weekly matching with zero carbon generation i.e. weekly correlation so that electricity used over the week the hydrogen is produced must equal the zero-carbon electricity procured in the same week. The effect is similar to monthly correlation (explained above) but the shorter time period makes it less favourable for electrolyser utilisation.
- 100% annual matching i.e. annual correlation so that electricity used over the year the hydrogen is produced must equal the zero-carbon electricity procured in the same year. The effect is similar to monthly correlation (explained above) but the longer time period makes it more favourable for electrolyser utilisation.
- Net Zero Short Run Marginal Emissions (Net Zero SRMEs) – hydrogen emissions are based on the amount grid emissions would increase as a result of the additional electricity demand.

Emissions were classed as Attributional and Consequential. The former is effectively the carbon intensity of the hydrogen produced, whilst the latter measures the additional grid emissions caused by the additional electricity demand of the electrolyser.

In the No Requirements scenario, the hydrogen carbon intensity would exceed the 45V requirement in all zones because the carbon intensity of the grid is too high. Emissions would also be higher than using methane reforming in 3 of the zones because the marginal generation used to meet electrolyser demand was fossil fuel based.

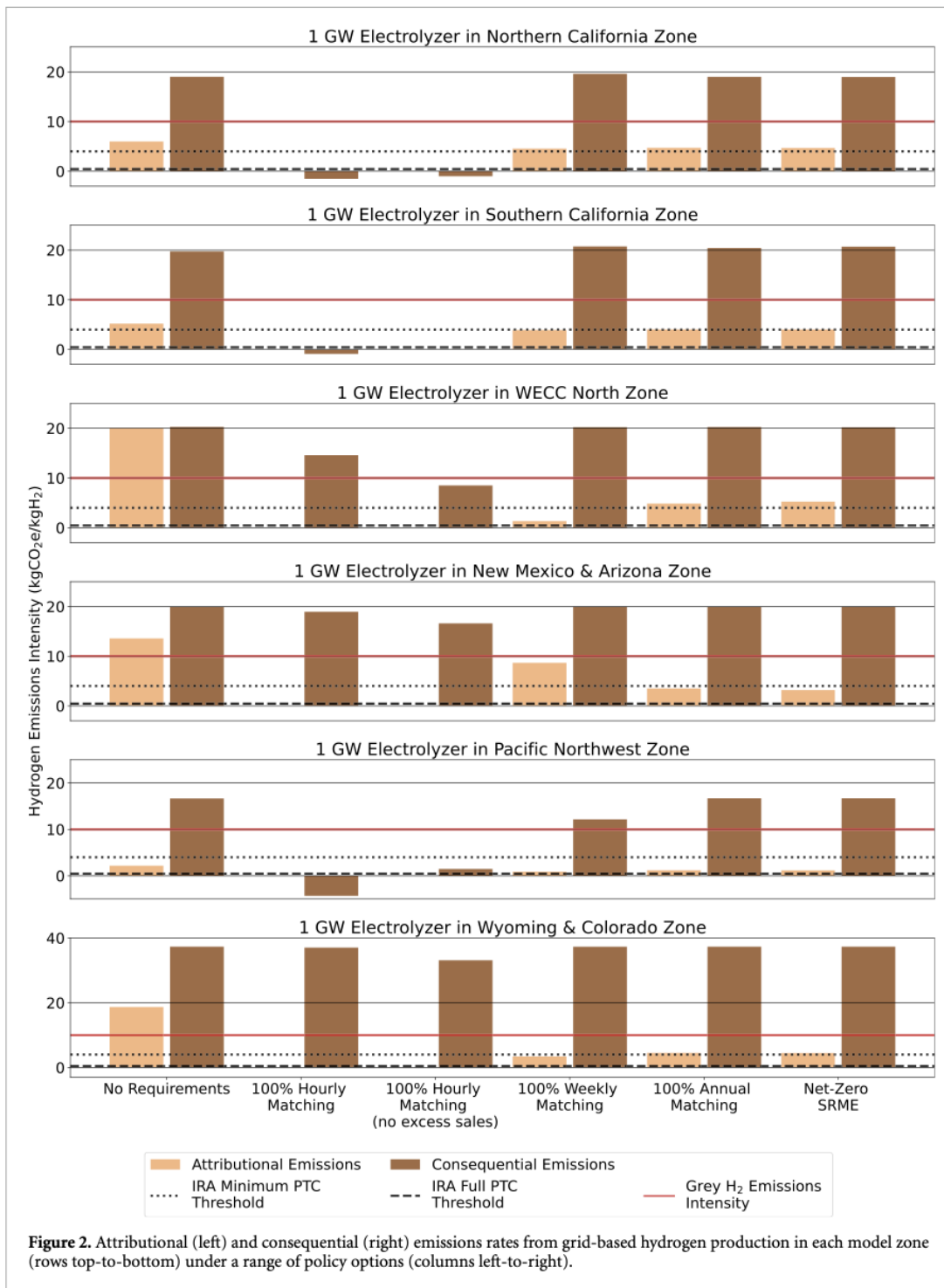
In the 100% Hourly matching scenario hydrogen carbon intensity meets the 45V requirements because electrolysers are forced to use only zero carbon electricity. Whilst the electrolyser, by definition, cannot consume fossil fuel-based grid electricity, it can lead to higher consequential emissions as a result of greater consumption of fossil fuel-based electricity by other consumers when renewable generation is scarce. Combining sales of excess renewable generation (i.e. not needed by the electrolyser) to the grid with hourly matching can reduce consequential emissions. However, the study found that sales of excess electricity to the grid were unpredictable and the increase in emissions due to greater use of fossil fuel-based generation by other users has the bigger effect. For example, the scarcity of renewable generation and hence its inability to meet electrolyser demand meant that less fossil fuel generation was retired than would otherwise have been the case. In the California and Pacific North West zones Consequential emissions were low or negative, but for the other grid consequential emissions were significant.

All the other scenarios had worse Attributional and Consequential emissions outcomes than the 100% hourly matching scenario. The difference with the 100% Hourly matching scenario depended on the grid concerned and its generational mix.

⁴⁷ Ricks, Xu, Jenkins (2023) 'Minimizing emissions from grid-based hydrogen production in the United States.' Environmental Research Letters. Wilson Ricks et al 2023 Environ. Res. Lett. 18 014025



Figure 13: Grid based hydrogen emissions under different scenarios in Western US



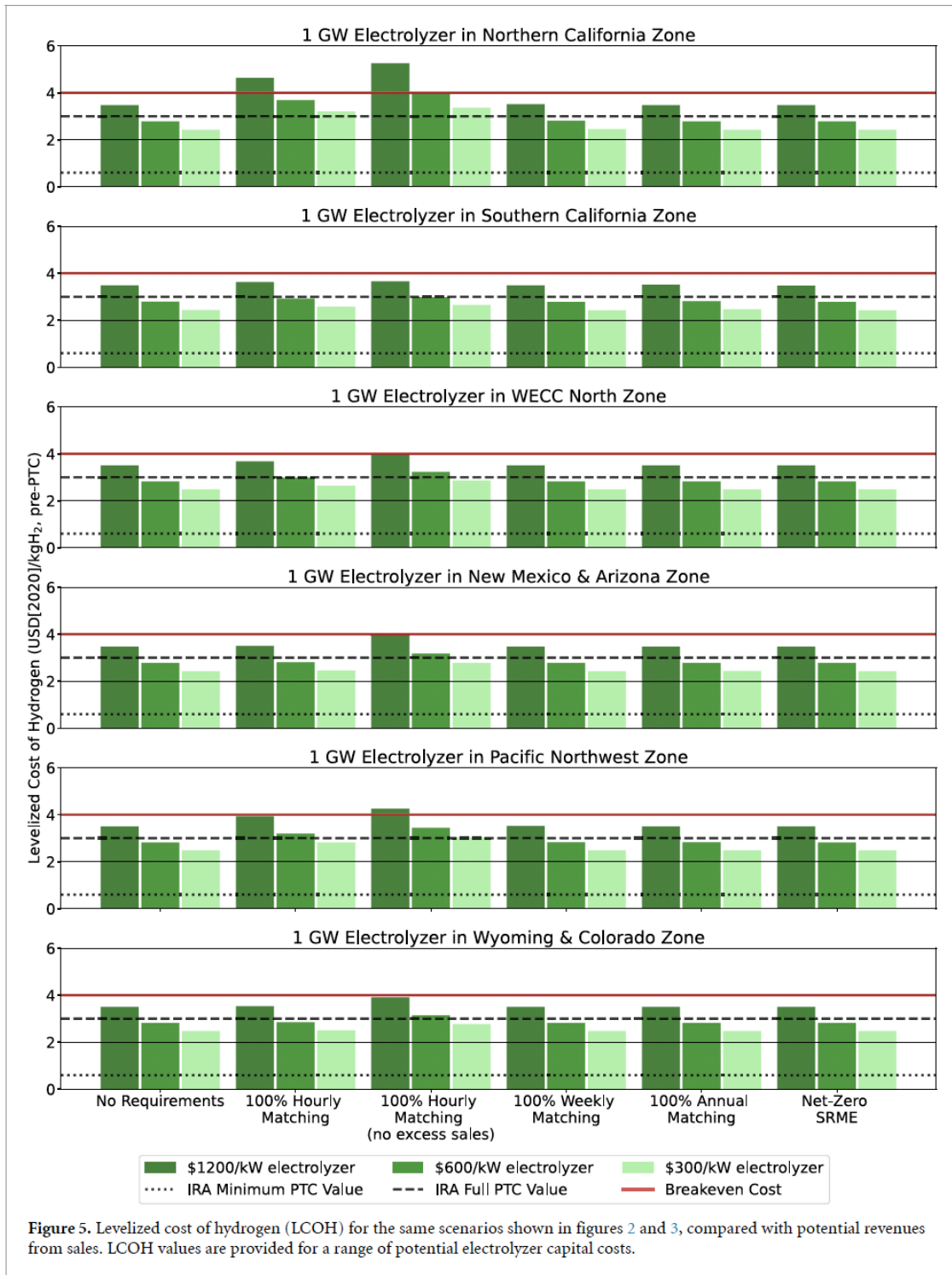
Source: Ricks, Xu, Jenkins (2023) [‘Minimizing emissions from grid-based hydrogen production in the United States.’](#) Environmental Research Letters. Wilson Ricks et al 2023 Environ. Res. Lett. 18 014025

The study also looked at deliverability (i.e. the impact of transmission constraints and hence the equivalent of a geographic correlation requirement) Transmission constraints were found to impact emissions by preventing clean electricity being delivered to the electrolyser, and to different marginal generating units being dispatched either side of a constraint. Persistent congestion also impacted generation capacity retirements and additions in the long run.



Significantly the study found that the stricter requirements did not lead to a much higher LCOH. Using the same scenarios, and comparing different electrolyser costs the study found that the stricter hourly matching requirements added between \$0 and \$1/kgH₂. Where there is plentiful renewable energy available, the additional cost is lower and can be near zero. The results are illustrated in Figure 14 below.

Figure 14: LCOH of grid based hydrogen under different scenarios in Western US



Source: Ricks, Xu, Jenkins (2023) [‘Minimizing emissions from grid-based hydrogen production in the United States.’](#) Environmental Research Letters. Wilson Ricks et al 2023 Environ. Res. Lett. 18 014025

The study concluded that ‘subsidized grid-connected hydrogen production has the potential to induce additional emissions at effective rates worse than those of conventional, fossil-based hydrogen production.’ Emissions can be minimised by ensuring hourly temporal correlation, additionality and physically deliverability (i.e. geographic correlation). Such measures ‘cannot eliminate indirect emissions caused by competition for limited clean resources’ but are better than alternative approaches with looser temporal correlation requirements.

The study does not specifically compare the additional cost of hydrogen as a result of the stricter conditions with the greater reduction in emissions compared to more relaxed requirements, but it is interesting to note that the differences in cost do not appear to be as great as the differences in emissions. A bigger driver in the increase in costs appears to be the prohibition on sales of excess electricity to the grid which indicates the value of allowing projects to trade with the grid. For example, the LCOH for an electrolyser in Wyoming in Colorado is similar in the 100% hourly matching, 100% weekly matching, 100% annual matching and Net Zero SRME cases, but the LCOH for 100% hourly matching without sales of excess power to the grid is noticeably higher. Even in zones where the LCOH for 100% hourly matching is higher than the other scenarios (e.g. Southern California) the LCOH for 100% hourly matching without excess sales is higher still.

5.7 Interaction with the grid

The importance of interaction with the grid is further illustrated by a study looking at the impact on hydrogen project design and economics, and power sector emissions using historic German electricity data.⁴⁸ The study modelled projects consisting of wind turbines, electrolyser and hydrogen storage, and compared how different regulatory requirements affected the projects design, LCOH and the impact on power sector emissions. It should be noted that the latter is not the same as the carbon intensity of the hydrogen itself – rather it is whether power sector emissions increase or decrease as a result of additional electricity demand on the power system due to the electrolyser. The study required that the electrolyser be supplied with electricity from additional generation, but then compared three scenarios:

- An island scenario where there was no connection to the grid so the electrolyser could only run when the wind turbine is generating. When wind generation was greater than electrolyser demand, generation was curtailed as the electricity could not be sold into the grid.
- Connection to the grid with hourly correlation so hydrogen production could only occur when there was sufficient wind generation on an hourly basis. However, in periods when the wind generation was greater than electrolyser demand the excess electricity was sold into the grid.
- Connection to the grid without hourly correlation. This allows the electrolyser to run when the wind generation is operating, and to buy low priced electricity from the grid when it is not. It also allows excess wind generation electricity to be sold to the grid.

The different scenarios led to different investment decisions in terms of sizing of the wind generation, electrolyser and hydrogen storage, different load factors for the electrolyser, and hence different LCOH. There were also differences in the amount of wind generation fed into the grid and hence the impact on the grid’s carbon intensity. Key results are summarised in Table 4 below.

⁴⁸ Ruhнау, Schiele (2023) ‘Flexible green hydrogen: The effect of relaxing simultaneity requirements on project design, economics, and power sector emissions.’ Energy Policy.

Table 4: LCOH and impact on power sector emissions under different scenarios in Germany

Year		Unit	Island System	Hourly correlation	Without hourly correlation
2017	LCOH	€/MWh _{H2}	187.40	137.47	99.81
	LCOH	€/kg _{H2}	6.18	4.54	3.29
	Power Sector Emissions	tCO ₂ /MWh _{H2}	0.00	-1.70	-0.03
2018	LCOH	€/MWh _{H2}	196.55	123.43	107.11
	LCOH	€/kg _{H2}	6.49	4.07	3.53
	Power Sector Emissions	tCO ₂ /MWh _{H2}	0.00	-2.43	-0.23
2019	LCOH	€/MWh _{H2}	205.68	129.34	98.38
	LCOH	€/kg _{H2}	6.79	4.27	3.25
	Power Sector Emissions	tCO ₂ /MWh _{H2}	0.00	-2.4	-0.13
2020	LCOH	€/MWh _{H2}	223.72	158.06	99.52
	LCOH	€/kg _{H2}	7.38	5.22	3.28
	Power Sector Emissions	tCO ₂ /MWh _{H2}	0.00	-1.9	0.01

Source: Ruhnau, Schiele (2023) 'Flexible green hydrogen: The effect of relaxing simultaneity requirements on project design, economics, and power sector emissions.' Energy Policy.

The results show that enabling trade with the grid reduces the LCOH and has a positive impact on the emissions of the grid. The latter is shown as the reduction in Power Sector emissions expressed as tCO₂ saved per MWh of hydrogen produced. This is driven by the injection of additional renewable electricity into the grid when the wind turbine output exceeds the electrolyser requirements. The authors conclude that a more flexible approach (i.e. without the hourly correlation) would both reduce the grid's carbon intensity and enable a lower LCOH. However, it is notable that, whilst the LCOH reduces in the scenario without hourly correlation, the CO₂ savings are minimal, and much less than in the scenario with hourly correlation. Using 2020 data the grid's carbon intensity actually increases. When one compares either the LCOH with the CO₂ saved, or the LCOH saving compared to the Island scenario with the CO₂ saved, the picture is much less favourable, as shown in Table 5 below.

Table 5: Comparison of LCOH and emissions reductions under different scenarios in Germany

Year	LCOH € per tCO ₂ saved		Reduction from island scenario LCOH € per tCO ₂ saved		Additional LCOH € per tCO ₂ saved
	Hourly correlation	Without hourly correlation	Hourly correlation	Without hourly correlation	
2017	80.9	3327.0	29.4	1255.3	22.55
2018	50.8	465.7	30.1	71.0	7.42
2019	53.9	756.8	31.8	238.2	13.64
2020	83.2	-	34.6	-	30.65

Source: Author's calculations based on data from Ruhnau, Schiele (2023) 'Flexible green hydrogen: The effect of relaxing simultaneity requirements on project design, economics, and power sector emissions.' Energy Policy.



LCOH € per tCO₂ saved takes the LCOH for each year and divides this by the saving (reduction) in power sector emissions. This gives an indication of the cost of hydrogen per tonne of CO₂ saved from allowing the hydrogen project to be connected to the grid, and therefore enabling surplus electricity to be sold into the grid. Note this does not take account of any CO₂ savings achieved by replacing fossil fuel with the hydrogen as the study does not provide the carbon intensity of the hydrogen produced. However, with hourly correlation with the wind generation the hydrogen will have a low carbon intensity which should enable further savings. Without hourly correlation the picture is less clear as the grid electricity which the electrolyser uses may have some fossil fuel generation, although the study notes that a lot of the time the electrolyser will be taking electricity from the grid when prices are low or negative, which indicates a high share of renewables, and hence a lower carbon intensity.

Reduction from island scenario LCOH € per tCO₂ saved is calculated by dividing the reduction in LCOH compared to the island scenario and dividing it by the CO₂ saved. Because the CO₂ saving in the scenario without hourly correlation is so small, the LCOH saving has a much higher cost in terms of CO₂ saved compared to the benefit of the LCOH reduction. To put it another way, consumers will be paying a higher price for the hydrogen in the hourly correlation scenario but the benefit in CO₂ savings is higher both in absolute terms (tCO₂ saved for each MWh of hydrogen produced) but also in monetary terms. An alternative way of gauging the impact of the stricter correlation rules in terms of CO₂ savings is to look at the additional LCOH of hourly correlation compared to without hourly correlation, divided by the additional CO₂ savings of the hourly correlation scenario. This is in effect a cost of carbon abated and is quite low compared to the EU ETS price.

Green Lab Skive (GLS) is an industrial park in Denmark which aims to become a test bed for converting renewable electricity to other forms e.g. hydrogen, heat and synthetic fuels using electrolysers connected to the renewable generation and the Danish grid. A 2023 study looks at how to optimise low carbon hydrogen production at GLS.⁴⁹ Unlike the German electricity study by Ruhnau and Schiele discussed above, the GLS study focuses on cost and carbon intensity of the hydrogen, not on the cost of hydrogen and the reduction of the carbon emissions by the grid. CO₂ intensity of hydrogen is based on hourly correlation in all scenarios i.e. the carbon intensity of the grid is measured on an hourly basis. In the GLS study the electrolyser is always connected to the grid, the variation between the scenarios depends on the sources of renewable electricity in addition to or instead of any grid supplied electricity, and the associate costs (i.e. investment in wind turbines or PV). The scenarios also include hydrogen storage. The model aims to optimise investment in electrolyser, electricity generation and storage to achieve the lowest LCOH and then compares the costs and carbon intensity. The study also compares the carbon intensity of the hydrogen to that produced by steam methane reforming (SMR), for which it quotes a value of 7kgCO₂/kgH₂.

The scenarios tested are:

- Electrolyser supplied only from the grid (Grid)
- Electrolyser supplied by PV and the grid (Grid + PV)
- Electrolyser supplied by wind turbine and the grid (Grid + WT)
- Electrolyser supplied by wind, turbine, PV and the grid (Grid + PV + WT).

The results are shown in Table 6 below.

Table 6: Comparing Hydrogen Carbon Intensity and LCOH scenarios for Green Lab Skive

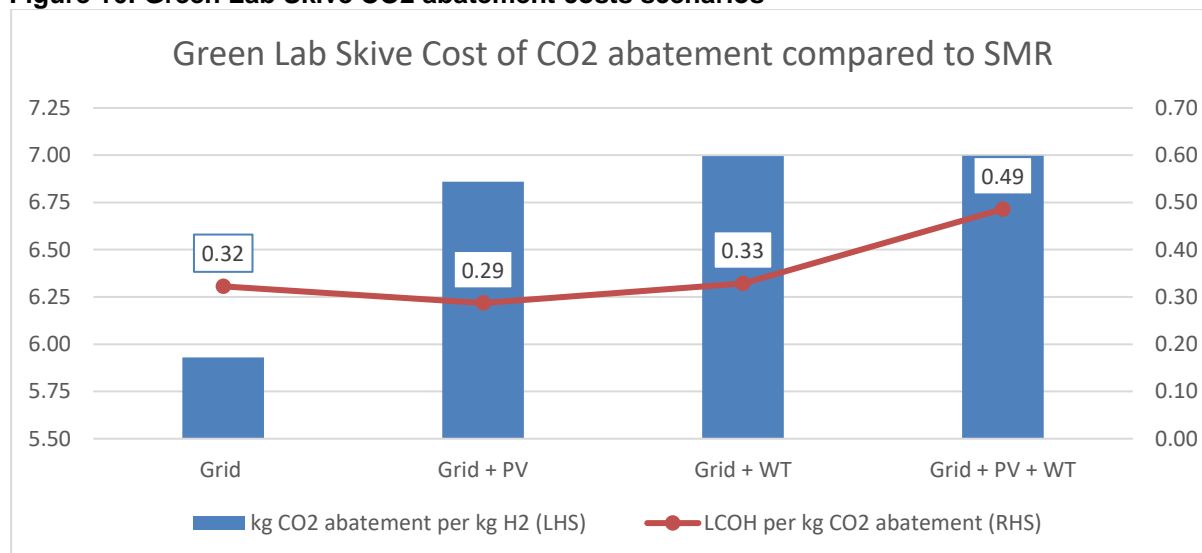
Green Lab Skive	Carbon Intensity kgCO ₂ /kgH ₂	LCOH €/kgH ₂
Grid	1.0700	1.91
Grid + PV	0.1400	1.97
Grid + WT	0.0043	2.30
Grid + PV + WT	0.0037	3.40

Source: Sorrenti, Zheng, Singlitico, You (2023) 'Low-carbon and cost-efficient hydrogen optimisation through a grid connected electrolyser: The case of Green Lab Skive.' Renewable and Sustainable Energy Reviews.

⁴⁹ Sorrenti, Zheng, Singlitico, You (2023) 'Low-carbon and cost-efficient hydrogen optimisation through a grid connected electrolyser: The case of Green Lab Skive.' Renewable and Sustainable Energy Reviews.

Using the LCOH results for the different scenarios, and comparing to the carbon intensity of SMR, Figure 16 can be derived.

Figure 16: Green Lab Skive CO2 abatement costs scenarios



Source: Author's calculations based on data from Sorrenti, Zheng, Singlitico, You (2023) 'Low-carbon and cost-efficient hydrogen optimisation through a grid connected electrolyser: The case of Green Lab Skive.' *Renewable and Sustainable Energy Reviews*.

The blue bars show the carbon saving for each scenario compared to the SMR value. The orange line then divides this value into the LCOH for each scenario to enable comparison of the CO2 abatement cost, as opposed to a simple comparison of the LCOH. Whilst the Grid scenario has a lower cost than the other scenarios, its carbon intensity is also much higher, resulting in a lower saving compared to SMR. (It should be noted however that the Danish grid has the fourth lowest overall carbon intensity in the EU27, and renewables have over 80% share of electricity demand. This means that the emissions saving would even less in most other EU countries). The Grid + PV scenario costs marginally more than the Grid scenario but has lower carbon intensity, resulting in a lower cost of hydrogen in terms of CO2 abatement. Grid + WT has higher LCOH than the Grid scenario but again has higher CO2 savings, so the cost of hydrogen in terms of CO2 abatement is only slightly higher. Whilst the CO2 savings of the Grid + PV + WT scenario are lower than the other scenarios, these additional CO2 savings are insufficient to outweigh the higher costs.

6. Reducing regulatory risk for low carbon hydrogen

Low carbon hydrogen faces regulatory uncertainty common with other energy sector businesses – government taxation, rules on market design, standards, general energy policy including climate change policies. It is much more vulnerable than most other sectors, however, because the business case is entirely dependent on large scale government intervention. Oil and gas are profitable without government support because they provide energy at low financial cost. Renewable electricity generation is becoming increasingly competitive with fossil fuel generation, can plug into an existing infrastructure and access existing markets and demand. None of these conditions apply to low carbon hydrogen which is much higher cost than fossil fuel alternatives (even where carbon pricing is in place) and faces considerable demand uncertainty. Existing infrastructure is also very limited or non-existent.

Without government subsidies, tax breaks or legally binding targets companies will not have the confidence to invest in low carbon hydrogen supply, infrastructure and demand. The only reason that governments are intervening to support low carbon hydrogen is the potential it offers to decarbonise parts of the economy. To look at it another way, if low carbon hydrogen made sense without government intervention, companies would be using it already. Therefore, to minimise regulatory uncertainty low carbon hydrogen needs to demonstrate to government that it is good value for money in terms of



reducing emissions. There are two aspects to this. Firstly, use of low carbon hydrogen must result in real reductions in emissions in the economy and not just shift emissions upstream from the end use point, for example to the hydrogen production process or the inputs to that process. Secondly low carbon hydrogen must be a lower cost solution than other approaches such as direct electrification of industry, or other forms of renewable energy storage. The two factors can be combined by comparing the cost of emissions avoided per kg of hydrogen. If low carbon hydrogen fails to do this, it may face the type of risks incurred by other low carbon businesses. Biomass has faced changing rules on its use and sustainability requirements because of concerns about competition with food crops. Use of wood based biomass in power generation and carbon offsets have been undermined by concerns about the robustness and reliability of their contribution to real emissions reductions. Nuclear power has faced stop-start support because of environmental (nuclear waste) and cost concerns.

The first step is to ensure that there is proper accounting of carbon intensity using hourly correlation of the inputs. As the examples above show this provides a more accurate picture of carbon intensity. Rules which deviate from this such as monthly or annual correlation, or system averaging, can give very different results simply because of the way the rules work, rather than the actual carbon intensity of the hydrogen. Consequently, the different rules also give a misleading picture of the true cost of emissions reduction, and hence can lead to a misallocation of resources. This can be both technology investment (electrolytic low carbon hydrogen vs. other low carbon hydrogen production pathways vs non hydrogen alternatives) and geographically. For example, if costs of hydrogen production in all EU countries are the same, it makes more sense for the EU to support investment in those European countries with lower carbon intensity grids as these will result in higher emissions reductions for a given subsidy. However, the looser monthly correlation or system averaging rules make it more difficult to distinguish between countries or local grids since, based on the rules rather than proper accounting, all countries appear to meet the same carbon intensity standard. The study of the US western grids illustrates the same problem. Loosening the rules also understates the investment needed in low carbon electricity to make low carbon hydrogen truly zero carbon as the analysis on the amount of electricity needed for DAC shows.

Whilst it is obvious that matching hydrogen production with low carbon electricity can lead to higher LCOH due to lower electrolyser utilisation, it is also clear that the impact of this can be very grid specific. For example, the US study shows a range of different LCOH when applying the stricter temporal correlation rules, and the scale of the difference between the strictest rules and the laxest also differs. The cost decrease by applying looser rules does not appear to be proportional to the increase in emissions. The Green Lab Skive case shows that additional investment in renewables can lead to LCOH per kg CO₂ saved which is very similar to that of the grid. Differences between grids and their generation mix mean that the impact of looser rules can differ hugely as the Bellona study shows. Modelling studies on the cost impacts, or the impacts of additional electrolyser demand on the carbon intensity of grids, are limited by their assumptions about costs and the rules underpinning the models. Whilst they are extremely helpful in showing how different correlation rules change outcomes of the models, they are not a forecast of what will happen. It is therefore better to have a proper accounting approach so that, whatever the evolution of the generation mix or the cost of electrolysers, stakeholders can make decisions based on the true costs, both in terms of hydrogen production (companies) and carbon reduction (governments).

Loosening the accounting rules to make it 'easier' for low carbon hydrogen to meet a given carbon intensity threshold is an inefficient way of compensating low carbon hydrogen projects for the higher LCOH caused by stricter rules. Not only does it not allow governments to distinguish properly between projects based on the real cost of reducing emissions, it is inflexible. Either producers meet the standard, or they do not. Moreover, at the point in time when the rules become stricter (2030 in the EU) companies face a 'cliff edge' – unless they can meet the new standard they face losing all or some of their support. If support is based on a carbon intensity basis with more support for hydrogen with a lower carbon intensity and less for that with higher, then producers no longer face the cliff edge, and they also potentially benefit from higher electrolyser utilisation rates if this leads to a lower LCOH than the reduction in support for higher carbon intensity hydrogen. The use of hourly correlation ensures that the hydrogen produced still leads to real reductions in emissions. The US 45V tax credit has a sliding scale based on different bands of carbon intensity.



Proper accounting of carbon intensity also enables the use of hydrogen which may be more carbon intensive itself, but still results in large emissions reductions if it is replacing high carbon hydrogen or reducing emissions in carbon intensive processes (e.g. steel making).. Governments can support projects which result in the largest overall reduction in emissions, rather than focus on the carbon intensity of hydrogen alone. This is more flexible as it may enable hydrogen projects which otherwise would not go ahead (e.g. retrofitting of CCS to existing SMR plants or use of electrolytic hydrogen to replace high carbon hydrogen) if solely judged on the hydrogen's carbon intensity. As it is the total emissions saved, and how quickly this can be done to remain within the carbon budget, governments should be basing decisions on hydrogen value chains which maximise emissions reductions in the shortest time period.

The UK's Low Carbon Hydrogen Standard combines strict temporal correlation (in this case 30 minutes) with the ability to average batches of hydrogen in terms of their carbon intensity. Irrespective of the production pathway the carbon intensity of the hydrogen is measured for each batch produced within a 30-minute period. If hydrogen is produced by the same method, then the carbon intensity of different 30-minute batches can be combined. So long as the weighted average carbon intensity of the combined batches meets the carbon intensity standard, then all the hydrogen qualifies for support. By maintaining proper measurement of carbon intensity, the weighted average and sliding scale approach enable governments to target support where it is most effective whilst providing companies with the clear framework they need to make efficient investment decisions. Moreover, the approaches do not hide the true cost of hydrogen in terms of emissions reduction unlike the looser rules approach. The argument that looser rules will speed up hydrogen deployment is probably true as it makes the cost of low carbon hydrogen in terms of emissions reduction appear lower than it really is. But it comes at the risk of misallocation of resources and potential adverse impacts in terms of emissions.

Stricter temporal correlation can also enable better integration between electrolyser and the grid, which can result in a lower LCOH and also benefits for the grid. The EU RFNBO rules are predicated on the assumption that renewable electricity has zero carbon intensity. However, there are a several complex rules which enable electricity to qualify as 'renewable' even if is not (for example the monthly temporal correlation rules). Alternatively, electrolysers have to demonstrate that they do not take electricity from the grid, which means their load factor is dependent on the load factor of their renewable electricity source. An approach based solely on the carbon intensity of the electricity, irrespective of the source of that electricity, ensures a real reduction in emissions, whilst enabling electrolysers to improve their load factor by accessing grid electricity when their renewable source is not generating, or taking advantage of cheap and low carbon grid electricity when prices are low. A connection to the grid also enables the hydrogen project to sell excess renewable electricity to the grid when it is not required by the electrolyser. Consequently, hydrogen projects can optimise their investments in renewable generation, electrolyser size and configuration, and hydrogen storage to achieve the best LCOH overall. The US study shows that allowing excess sales with hourly correlation results in a lower LCOH than hourly correlation without excess sales, and also an LCOH which is comparable to the LCOH with laxer temporal correlation rules in some cases. The Green Lab Skive case study shows that a combination of grid electricity and PV results in a lower LCOH per kg of CO₂ saved than using grid electricity alone. The German grid study shows that allowing grid connections results in lower grid emissions for each kg of hydrogen produced, with the biggest reduction being in the scenario where hourly correlation is applied.

Use of stricter temporal correlation could also lessen the need for additional requirements. The UK LCHS does not have an additional requirement, unlike the proposed US and EU rules. The US study authors concluded that additional requirements were still needed if hourly correlation rules were in place. However, there is a risk that additional rules applied to low carbon hydrogen production alone may tilt the playing field unfairly in other technologies favour. Whilst the risk of increased emissions without additional investment is real, it applies to any increased used of electricity, not just that of electrolysers. If additional consumers of electricity are not required to demonstrate the carbon intensity of their electricity, it means they can claim to have reduced emissions at the point of use whilst all they have done is potentially shift emissions upstream to the electricity grid. If such additional electricity consumers do not face additional requirements whilst low carbon hydrogen does, the costs of LCOH are increased relative to electrification. With only a carbon intensity target based on temporal correlation, electrolysers still have an incentive to make sure that they have sufficient low carbon intensity electricity



to supply the electrolyser as an increase in grid carbon intensity reduces the time the electrolyser will be able to use grid electricity. This may not avoid the ‘robbing Peter to pay Paul’ effect when electrolysers contract existing low carbon electricity and thereby other electricity consumers use more high carbon intensity electricity. In this case additional capacity may be required. However, allowing the use of grid electricity may enable electrolyser projects to invest in less of their own renewable generation if they believe the grid will continue to decarbonise enabling them to access sufficient low carbon grid electricity to top up their directly contracted low carbon electricity.

Lastly strict temporal correlation rules, particularly if combined with sliding scale support based on the carbon intensity of low carbon hydrogen, enable a simplification of the rules which reduces regulatory uncertainty for projects, both in terms of understanding the current rules, and the risk of future rule changes. The EU rules on what qualifies as renewable electricity for RFNBO production are very complex – so much so that the EU Commission has had to issue two sets of guidance in the twelve months since the rules introduction in 2023 to help companies understand them. Simplification of rules also enables companies to make better comparisons between jurisdictions and limits the potential for regulatory arbitrage based on rules’ complexity rather than on economic grounds.

Whilst much of the focus of this paper has been on the carbon intensity of electrolytic hydrogen, the same rigorous approach should be applied to other production pathways. Of particular focus should be the upstream emissions associated with the production and transport of oil, natural gas or coal used. For example, oil, natural gas and coal all have methane emissions associated with production and transport, and this is an area which is still evolving in terms of measurement and regulation. Proper accounting for GHG emissions associated with fossil fuel production and transport would be beneficial in comparing the carbon intensity of low carbon hydrogen but also fossil fuels while they continue to be used.

Proper comparison between low carbon hydrogen produced in different countries is essential to take advantage of the comparative advantage some countries could have in producing low carbon hydrogen, whether that is based on access to cheap renewable electricity or low-cost natural gas and CCS. This requires two necessary conditions – a common methodology for measuring emissions along the value chain, and a common nomenclature to avoid the confusion over terms (the ‘Humpty Dumpty problem’). The current colour-based approach is unsuitable, whilst the terms ‘low carbon’ or ‘clean’ or ‘renewable’ can mean different things in different jurisdictions. The IEA has already called for hydrogen definitions to be based on emissions intensity⁵⁰ whilst the COP 28 Declaration of Intent on Hydrogen calls for the ‘mutual recognition of certification schemes for renewable and low carbon hydrogen and hydrogen derivatives.’⁵¹ A common nomenclature could be based on emissions intensity in the same way that maritime fuel is graded according to sulphur content which the IMO has used to reduce SOx emissions from shipping.⁵² The IEA suggests a ‘set of nine distinct, technology-neutral levels, ranging from emissions intensities below zero (level “A”) to an upper value of 7 kg CO₂-eq/kg H₂ (level “I”).’⁵³

The common methodology could be based on the IPHE Methodology for Determining the Greenhouse Gas Emissions Associated with the Production of Hydrogen. The COP 28 declaration specifically references this. The IPHE methodology does not set carbon intensity thresholds, and notably does not set a temporal correlation time period. It simply notes that emissions should be based on the ‘shortest timeframe reports available in the region.’⁵⁴ However it does provide a foundation methodology for calculation of emissions along the value chain including upstream, production and downstream emissions. Use of a common methodology would still enable countries to set their own carbon intensity thresholds, the level of support to provide and how to provide it.

⁵⁰ IEA (2023), [Towards hydrogen definitions based on their emissions intensity](#), IEA, Paris Licence: CC BY 4.0

⁵¹ <https://www.cop28.com/en/cop28-uae-declaration-on-hydrogen-and-derivatives>

⁵² <https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx>

⁵³ IEA (2023), [Towards hydrogen definitions based on their emissions intensity](#), IEA, Paris Licence: CC BY 4.0. Box 3.1 page 68.

⁵⁴ Hydrogen Production Analysis Task Force (2023). ‘[Methodology for determining the greenhouse gas emissions associated with the production of hydrogen.](#)’ Version 3. International Partnership for Hydrogen and Fuel Cells in the Economy



7. Conclusions

The reason d'être for low carbon hydrogen is that it will assist governments in their efforts to decarbonise their economies. This in turn depends on the cost effectiveness of low carbon hydrogen in doing so. If low carbon hydrogen fails to demonstrate this it risks losing the government support it needs for companies to invest in the sector, a major source of regulatory risk. Markets are best placed at managing those risks that can easily be internalised – financial costs, project implementation – but are less able to deal with externalities such as GHG emissions. Governments can enable markets to bring down the cost of low carbon hydrogen by providing a stable and clear regulatory framework. Crucially this includes proper accounting of low carbon hydrogen's carbon intensity, alongside common accounting standards and nomenclature. To date efforts to provide this have been disjointed and confusing, made worse by a focus on production pathways in the EU. Industry lobbying to have looser carbon accounting standards could be counter-productive in the long term if it opens low carbon hydrogen open to accusations of 'greenwashing' as a result of understating the true carbon intensity. Only rigorous accounting standards, backed up by flexible government support based on carbon intensity, will enable investment in low carbon hydrogen supply, infrastructure and demand where it makes the most sense - both financially and environmentally.